Analysis of the Santee Cooper Rate Base for V.C. Summer Nuclear Units 2 & 3

Joint Resolution H.4287

South Carolina
Office of Regulatory Staff
September 16, 2019

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V.C. Summer Nuclear Units 2 & 3

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Executive Summary

On May 22, 2019, Governor McMaster signed into law Joint Resolution Act 95 (H.4287) which required the Department of Administration, among other tasks, to "[r]equire that the bidder's projected ratebase for all of Santee Cooper's retail customers exclude any portion of debt attributed to the V.C. Summer nuclear units 2 and 3 that is not considered to be used and useful as determined by the professional services experts and the Office of Regulatory Staff."[1]

To assist the Department of Administration, the South Carolina Office of Regulatory Staff (ORS) completed an analysis and determined the portion of ratebase attributed to the V.C. Summer Nuclear Units 2 and 3 that is not used and useful totals $4,235,100,000 as of December 31, 2018. Exclusion of the ratebase attributed to V.C. Summer Nuclear Units 2 and 3 will consequently exclude the corresponding debt.

ORS determined that $1,609,338,000 is the portion of ratebase attributed to V.C. Summer Nuclear Units 2 and 3 that is not used and useful and should be excluded from the bidder's projected ratebase for Santee Cooper's retail customers.

This Report and Attachments contain the ORS analysis, calculation, and supporting information.

[1] H.4287 Section 2(B) paragraph 5

Definitions

H.4287 does not define the term "ratebase." For the purposes of this analysis, ORS employed the definition commonly used in public utility ratemaking. Ratebase is defined as the plant facilities and other assets used in supplying utility service to the consumer.[2] Components of ratebase include, but are not limited to:

- plant in service
- accumulated depreciation
- construction work in progress (CWIP)
- contributions in aid of construction (CIAC)
- cash working capital
- regulatory liabilities
- fuel inventories
- materials & supplies
- prepayments
- customer advances
- regulatory assets

Likewise, H.4287 does not define the phrase "used and useful." For the purposes of this analysis, ORS employed the definition commonly used in public utility ratemaking and supported by seminal utility rate cases *Hope* and *Bluefield.* See, *Bluefield Waterworks & Imp. Co. v. Public Service Commission of W. Va*., 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923), *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1944). In *Bluefield*, the Court established that "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public…." 262 U.S. 679 at 692, 43 S.Ct. at 679, 67 L.Ed. at 1182-83. See also, 8 ENERGYLJ 303, 333 (1987) ("Regulators still determine whether utility investments are or are not used and useful in the public service and thereby establish whether or when certain investments are recoverable.")

Simply stated, used and useful is defined as plant facilities and assets owned by Santee Cooper that provide service to customers. If a utility plant is not in service to customers, it is not considered used and useful.

Analysis Approach

On June 25, 2019, ORS engaged in discovery with Santee Cooper. Santee Cooper's responses to the ORS discovery were used to perform ORS's analysis.[3] In addition, ORS reviewed publicly available information which included: 1) Annual Report 2018[4] and 2) August 22, 2018 and September 5, 2018 Presentations to the Public Service Authority Evaluation and Recommendation Committee.[5] The Annual Report 2018 contains audited financial statements for the year ending December 31, 2018.

[2] Deloitte. *Regulated utilities manual A service for regulated utilities,* 2012. p.45. http://ipu.msu.edu/wp-content/uploads/2017/09/Deloitte-Regulated-Utilities-Manual-2012-2.pdf

[3] Attachment B - Santee Cooper Responses to ORS Discovery Requests

[4] Attachment A - Annual Report 2018

[5] https://www.scstatehouse.gov/CommitteeInfo/PublicServiceAuthorityEvaluationandRecommendation/Main.php

V.C. Summer Nuclear Units 2 and 3 Ratebase

ORS determined, based on review and analysis of Santee Cooper's discovery responses and the Annual Report 2018, that the following ratebase components attributed to V.C. Summer Nuclear Units 2 and 3 are not used and useful to customers of Santee Cooper and should be excluded from the bidders projected ratebase.

Schedule 1:

Regulatory Asset - Nuclear Impairment	$ 4,198,000,000
Add: Regulatory Asset - Post Suspension Interest	$ 37,100,000
Total V.C. Summer Nuclear Units 2 & 3 Ratebase Components – Not Used and Useful	$ 4,235,100,000

Regulatory Asset – Nuclear Impairment

The Annual Report 2018 stated:

> On January 22, 2018, the Board approved the use of regulatory accounting for the $4.211 billion impairment write down. The majority of the Project was financed with borrowed funds. For rate-making purposes, the Authority includes the debt service on these borrowed funds in its rates. As such, the impairment will be recorded as a regulatory asset and amortized through November 2056 to align with the associated debt principal payments. In the event the principal maturities change materially the amortization will be adjusted to better align with the new maturities. In 2018, there was a decrease of $8.3 million charged to the nuclear impairment regulatory asset for adjustments after year end 2017, as well as amortization of $4.9 million.[6]

Regulatory Asset – Post Suspension Interest

The Annual Report 2018 stated:

> On December 11, 2017 the Board issued a resolution authorizing the use of regulatory accounting to defer a portion of the post suspension Project interest. With the cessation of capitalized interest and the timing of the suspension the Authority would be unable to collect a portion of the post suspension Project interest in rates. The regulatory asset for post suspension nuclear interest totaled $37.1 million and will be amortized through November 2056 to align with the principal payments on the debt used to pay the interest.[7]

[6] Attachment A - Annual Report 2018 p. 25
[7] Attachment A - Annual Report 2018 p. 26

Retail Customer Allocation

Santee Cooper classifies "retail" customers as customers that are directly served by Santee Cooper, and not indirectly through a wholesale provider, such as the electric cooperatives. Santee Cooper's retail customers include residential, commercial, industrial, and lighting customers.

To determine the allocation to retail customers as required by the Joint Resolution, ORS analyzed the data provided by Santee Cooper in response to ORS's discovery and information contained in the Annual Report 2018. Santee Cooper provided ORS with the 2015 Electric System Cost of Service and Rate Design Study (2015 Study) which provided a summary of the allocation for base rate increases for retail customers in 2016, 2017, and 2018. Santee Cooper has not updated the 2015 Cost of Service Study. According to information provided by Santee Cooper, the Board of Directors approved a series of two annual base rate increases for its retail customers on December 7, 2015. These two increases were effective as of April 1, 2016, and April 1, 2017, respectively.

Based on the 2015 Study, it appears that most Santee Cooper's electric services are devoted to meeting the needs of wholesale electric customers. Wholesale customers, which include Central Electric Power Cooperative, Inc., are served by Santee Cooper under individual electric service agreements. Unlike a regulated utility Cost of Service Study and Cost Allocation Manual, the 2015 Study does not include a detailed allocation of Santee Cooper's total ratebase to serve wholesale customers. The 2015 Study contains total revenues required to provide electric service to retail and wholesale customers, and segregates required revenues directly attributed to wholesale customers. It appears the remaining balance of required revenues were allocated to retail customers.

ORS determined the 2015 Study did not contain sufficient information to determine with precision the allocation of total expenses to Santee Cooper's retail customers. Therefore, ORS determined a proxy should be used to estimate the allocation of ratebase attributed to retail customers. The proxy allocation is based on percentage revenues collected for electric service for each customer class as reflected in the 2018 Annual Report.

Schedule 2 below identifies the revenues collected for the year ending December 31, 2018 for three (3) classes of customers. Santee Cooper reports revenues for the industrial customer class separate from the rest of the retail class. The lighting class of customer is included in the retail customer classification.

Schedule 2:

Customer Class	2018 Revenue ($000)[8]	Percentage of Revenue
Retail	$428,820	24%
Industrial	$245,117	14%
Wholesale	$1,106,826	62%
Total Revenue	**$1,780,763**	**100%**

Using a proxy for a Cost of Service Study, ORS determined an allocation percentage for retail customers of approximately 38% (24% for retail + 14% for Industrial). ORS applied the proxy allocation percentage to the ratebase determination in Schedule 1. ORS determined the ratebase that is not used and useful and should be excluded from the bidder's proposal is estimated to be $1,609,338,000 for retail customers.

Schedule 3:

Total V.C. Summer Nuclear Units 2 & 3 Ratebase Components - Not Used and Useful[9]	$4,235,100,000
Multiply: Retail Allocation of Ratebase[10]	38%
Retail Portion of V.C. Summer Nuclear Units 2 & 3 Ratebase Components - Not Used and Useful	**$1,609,338,000**

8 Attachment A – Annual Report 2018, p.17
9 Schedule 1
10 Schedule 2

Attachments

LIVING THE MISSION

Annual Report 2018

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Letter from the Chairman and CEO

Santee Cooper was built on the mission of improving the lives of all South Carolinians. Many things have changed in the past 84 years, but one thing has not – Santee Cooper's employees continue to live our mission each and every day. We accomplish that by providing low-cost, reliable power and water with excellent customer service, practicing environmental stewardship, driving economic development, and supporting our communities and local schools through volunteerism and educational campaigns.

Last year signaled a year of recovery, giving Santee Cooper employees the opportunity to rise to many challenges and succeed in our mission. We began 2018 faced with a massive ice and snow storm on Jan. 3. In addition to the precipitation, Winter Storm Grayson delivered a string of days with below-freezing temperatures that affected some generating equipment. Station employees worked through extreme conditions to make sure we met customers' power needs throughout the event.

In addition, teams at our Energy Control and Distribution Control centers faced various challenges to the transmission and distribution systems. They, along with bulk power marketing, worked around the clock to secure sufficient energy to meet Santee Cooper's demands as we repaired lines and equipment to make sure electricity continued to flow to customers.

September brought another natural disaster in the form of Hurricane Florence, which lumbered into South Carolina on Sept. 14 as a tropical storm and heavy rainmaker. Employees quickly returned service to our transmission and distribution customers, including 50,310 retail customers, but Hurricane Florence also brought historic flooding and threatened the stability of the ash ponds at the former Grainger Generation Station, adjacent to the Waccamaw River in Conway. We have been excavating Grainger's two ash ponds since 2014 and had only 13 percent of the ash left to remove.

We needed to protect the Waccamaw River as the floodwaters rose. More than 290 employees from several departments took part in securing the ash pond dikes, preventing ash migration into the Waccamaw, monitoring conditions through visual inspections and water sampling, and communicating with officials and the public.

Employees worked for more than a month as the waters rose and slowly receded. The effort involved collaboration with several other organizations, including the South Carolina Department of Health and Environmental Control, the National Guard, the Waccamaw Riverkeeper, and others. In the end, we succeeded in containing the ash and protecting the Waccamaw.

It was also a year of recovery for the utility after the cancelation of the V.C. Summer nuclear expansion. Santee Cooper's Board and management team have remained focused through 2018 on controlling costs and offsetting debt related to the nuclear project. Santee Cooper remains on solid financial footing, and we have a plan to gradually pay off that debt while maintaining competitive rates.

Part of that plan includes continuing to optimize and execute the use of the Toshiba Corp. settlement proceeds to reduce customers' cost by defeasing current debt outstanding and paying capital expenditures; thus, foregoing new debt issues. The deployment of the $898.7 million settlement is projected to provide approximately $1.4 billion aggregate savings to our customers. To date, we have utilized $521.3 million to defease debt outstanding, resulting in a debt service savings of approximately $693.8 million. We have also spent approximately $167.3 million for capital expenditures prolonging the need to enter the bond market for new proceeds.

In addition, we took steps to preserve the high-value equipment on the construction site after majority owner SCE&G abandoned it in order to maximize our ability to recover costs through sale of that equipment. Internally we have identified areas to cut costs, such as not replacing many of the 150 employees who retired in 2018.

Santee Cooper is committed to helping customers utilize solar and become more energy efficient, which helps reduce costs for the customer and the utility. In 2008, our Board of Directors set a goal that we help customers achieve annual energy savings of 209 gigawatt hours, which equates to more than $250 million, through energy-efficiency programs by the end of 2020. We're proud to say we realized that goal two years ahead of schedule.

Santee Cooper's Reduce The Use programs have helped more than 73,000 of our approximately 185,000 residential and commercial direct-service customers save energy and money. The energy-efficiency programs offer customers a variety of rebates on products ranging from smart thermostats for their homes to lighting controls for their businesses. We also provide the Smart Energy Loan program, a low-interest loan that allows customers to make energy-efficiency upgrades such as high-efficiency electric heat pumps, duct replacements and heat pump water heaters. Additional energy savings come through our solar programs, whether customers install solar panels on their roofs or subscribe to Solar Share, the first community solar program in the state. From the new solar programs' inception in April 2016 through the end of 2018, 618 customers have participated.

Last year Santee Cooper increased our own solar generation when we opened the Bell Bay Solar Farm, with approximately 2 MW of power output generated by 5,904 solar panels, in Bucksville. Bell Bay has been designed to maximize solar energy output in the afternoon to coincide with the Grand Strand's peak energy usage. We engineered the tilt of the solar panels to take full advantage of the afternoon summer sun, when customers use the most electricity. We'll study the results of this new approach for future solar farms.

In addition, we began the process of permitting and building Jamison Solar Farm near Orangeburg and Runway Solar Farm near the Myrtle Beach International Airport. All of our recent solar farms have been built with the help of Green Power funds.

Part of Santee Cooper's mission involves promoting economic development to create jobs and capital investment for South Carolina. Our largest industrial commerce park to date, Berkeley County's Camp Hall, moved forward with an official groundbreaking ceremony in June. In addition to anchor tenant Volvo Car USA, which is already manufacturing automobiles there, Camp Hall has already attracted a logistics developer planning two speculative buildings. Camp Hall electric needs are served by Berkeley Electric Cooperative, Edisto Electric Cooperative and Santee Cooper.

The Board of Directors took steps to increase economic development efforts by expanding several existing loan and grant programs available to local governments and electric cooperatives, and creating new initiatives that will help move economic development forward throughout the state.

Santee Cooper has maintained high marks in reliability and customer satisfaction. Transmission reliability for 2018 was 99.9973 percent, meaning the average delivery point was without power for only 14.22 minutes for the year. Distribution reliability was 99.9961 percent, equating to the average customer being without power for only 20.6 minutes for the year. Our residential, commercial and industrial customer service satisfaction rates were above 90 percent, with our industrial customer satisfaction coming in at 100 percent.

As 2018 ended, a legislative committee was working through an evaluation of Santee Cooper and consideration of opportunities for privatization, with recommendations to the full legislature expected in 2019. Santee Cooper has cooperated fully in that process, providing information and answering questions in a timely manner, to help legislators arrive at the best decision for South Carolina.

As we look back at 2018, one additional accomplishment stands out: our employees achieved the strongest safety record to date. This is especially remarkable given the many challenges associated with weather. In fact, the September effort caused by Hurricane Florence produced a successful response with zero safety incidents.

Santee Cooper achieved much in 2018 thanks to our 1,653 employees, who work tirelessly for our customers and continue to support the communities in which they work and live. As we begin 2019, we remain focused on living the mission and doing the best we can for customers and the state of South Carolina.

Charlie M. Condon
Interim Chairman

James E. Brogdon
Interim President and CEO

Corporate Statistics

System Data 2018

Miles of transmission system lines: ....**5,146**[1]

Miles of distribution system lines: **2,967**

Number of transmission substations: **106**

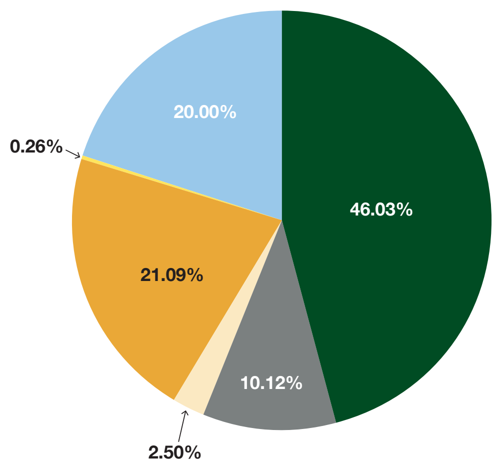
Number of distribution substations: **54**

Number of CEPCI Delivery Points (DPs): **465**

[1] Includes Central-owned transmission lines

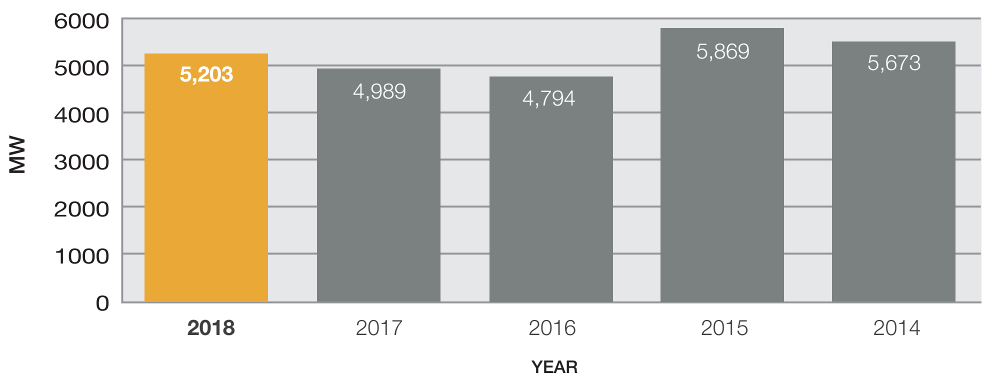
	2018	2017	2016	2015	2014
FINANCIAL (Thousands)					
Total Revenues & Income	**$1,963,805**	$1,732,327	$1,718,565	$1,842,541	$2,023,414
Total Expenses & Interest Charges	**$1,765,866**	$1,618,084	$1,604,119	1,781,591	1,894,217
Other	**($4,286)**	($5,561)	($6,708)	(6,435)	19,798
Reinvested Earnings	**$193,653**	$108,682	$107,738	54,515	148,995
OTHER FINANCIAL					
(Excluding CP and Other)					
Debt Service Coverage *(prior to Distribution to State)*	**1.54**	1.51	1.55	1.45	1.53
Debt / Equity Ratio	**75/25**	78/22	79/21	78/22	75/25
STATISTICAL					
Number of Customers (at Year-End)					
Retail Customers	**185,116**	180,658	176,748	174,023	171,567
Military and Large Industrial	**27**	26	27	27	28
Wholesale	**4**	4	4	4	4
Total Customers	**185,147**	180,688	176,779	174,054	171,599
Generation (GWh):					
Coal	**11,130**	9,589	12,347	12,832	16,607
Nuclear	**2,447**	2,296	2,886	2,366	2,297
Hydro	**603**	382	444	523	506
Natural Gas and Oil	**5,101**	5,783	4,834	6,212	3,821
Landfill Gas and Renewables	**62**	73	81	93	96
Total Generation (GWh)	**19,343**	18,123	20,592	22,026	23,327
Purchases, Net Interchanges, etc. (GWh)	**4,838**	4,980	3,433	4,987	4,738
Wheeling, Interdepartmental, and Losses	**(463)**	(324)	(325)	(515)	(712)
Total Energy Sales (GWh)	**23,717**	22,779	23,700	26,498	27,353
Summer Maximum Continuous Rating (MCR) Generating Capability (MW)	**5,112**	5,104	5,104	5,093	5,182
Territorial Peak Demand (MW)	**5,203**	4,989	4,794	5,869	5,673

2018 GENERATION BY FUEL MIX

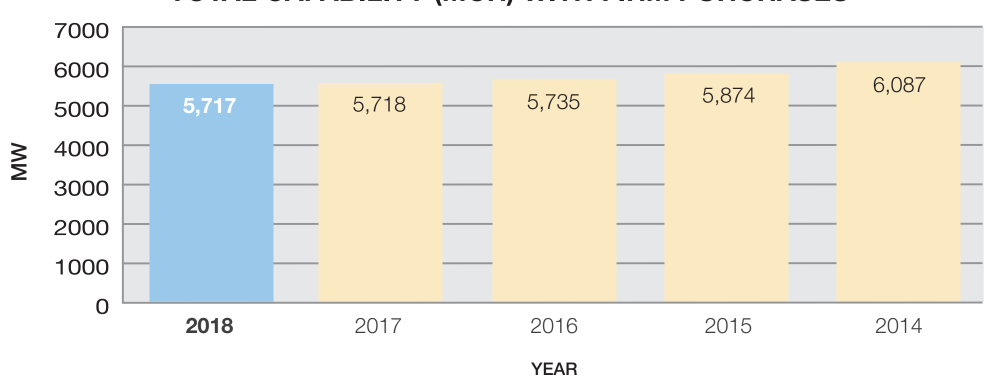


Source		GWh
Coal	46.03%	11,130
Nuclear	10.12%	2,447
Hydro	2.50%	603
Natural Gas & Oil	21.09%	5,101
Other Renewables	0.26%	62
Purchases (Net)	20.00%	4,838
	100.00%	24,181

PEAK DEMAND



TOTAL CAPABILITY (MCR) WITH FIRM PURCHASES



Audit Committee Chairwoman's Letter

The Audit Committee of the Board of Directors is comprised of independent directors Peggy H. Pinnell – Chairwoman, Charlie M. Condon – ex officio, William A. Finn, Merrell W. Floyd, Charles H. Leaird and Stephen H. Mudge.

The committee receives regular reports from members of management and Internal Audit regarding their activities and responsibilities.

The Audit Committee oversees Santee Cooper's financial reporting, internal controls and audit process on behalf of the Board of Directors.

Periodic financial statements and reports pertaining to operations and representations were received from management and the internal auditors. In fulfilling its responsibilities, the committee also reviewed the overall scope and specific plans for the respective audits by the internal auditors and the independent public accountants. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent public accountants and with the General Auditor to discuss the results of the audit, the evaluation of Santee Cooper's internal controls, and the overall quality of Santee Cooper's financial reporting.

Peggy H. Pinnell

Peggy H. Pinnell
Chairwoman
2018 Audit Committee

Notes:
Chairman Condon joined the Santee Cooper Board of Directors and the Audit Committee on July 23, 2018. The term of the Board Chair expires on May 19, 2025. However, Chairman Condon was appointed as an Interim Appointment. Subsequently, on Jan. 29, 2019, he was renominated by the Governor to serve as Board Chair. He will serve as Interim Chairman until either the appointment is approved or until the end of the regular 2019 legislative session, whichever occurs first.

Director Leaird joined the Santee Cooper Board of Directors and the Audit Committee on June 28, 2018.

Director Wolfe resigned from the Santee Cooper Board of Directors on June 27, 2018.

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Cherry Bekaert LLP
CPAs & Advisors

Report of Independent Auditor

The Advisory Board and Board of Directors
South Carolina Public Service Authority
Moncks Corner, South Carolina

Report on the Financial Statements

We have audited the accompanying financial statements of the business-type activities and fiduciary activities of the South Carolina Public Service Authority (the "Authority") (a component unit of the State of South Carolina), as of December 31, 2018 and 2017, and for the years then ended, and the related notes to the financial statements, which collectively comprise the Authority's basic financial statements as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express opinions on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Audit Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Authority's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinions.

Opinions

In our opinion, the financial statements referred to above present fairly, in all material respects, the respective financial position of the business-type activities and fiduciary activities of the Authority as of December 31, 2018 and 2017, and the respective changes in financial position and, where applicable, its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Other Matters

Emphasis of Matter

As discussed in Note 7 to the basic financial statements, significant events occurred in the prior year related to the Summer Nuclear Units 2 and 3 Project (the "Project"). The construction of the Project was suspended and the related capitalized assets were determined to be impaired and ultimately reclassified as a regulatory asset. In addition, a settlement was reached under a guarantee with the parent of the construction contractor, the amount of which has been classified under regulatory accounting as a deferred inflow. Also as result of the suspension of the Project, there is significant ongoing activity that is discussed in Notes 10 and 16 to the basic financial statements related to Legislative and Legal Matters. Our opinions are not modified with respect to these matters.

As discussed in Note 15 to the financial statements, the Authority adopted Governmental Accounting Standards Board Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefit Plans Other Than Pensions.* As a result, the Board approved the use of regulatory accounting to offset the initial net OPEB liability. Our opinions are not modified with respect to this matter.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis and the required supplemental financial data as listed in the table of contents ("RSI") be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the RSI in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audits of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audits were conducted for the purpose of forming opinions on the financial statements of the Authority's business-type activities and fiduciary activities. The Chairman and CEO Letter, Corporate Statistics, Audit Committee Chairwoman's Letter, Leadership, and Office Locations, as listed in the table of contents of the annual report, are presented for purposes of additional analysis and are not a required part of the financial statements. Such information has not been subjected to the auditing procedures applied in our audits of the financial statements and, accordingly, we do not express an opinion on them.

Other Reporting Required by *Government Auditing Standards*

In accordance with *Government Auditing Standards*, we have also issued our report dated February 28, 2019 on our consideration of the Authority's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, grant agreements, and other matters. The purpose of the report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Authority's internal control over financial reporting and compliance.

Cherry Bekaert LLP

Raleigh, North Carolina
February 28, 2019

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The South Carolina Public Service Authority ("the Authority" or "Santee Cooper") is a component unit of the State of South Carolina (the "State"), created by the State in 1934 for the purpose of providing and aiding interstate commerce, navigation, electric power and wholesale water to the people of South Carolina. The statute under which it was created provides that the Authority will establish rates and charges so as to produce revenues sufficient to provide for payment of all expenses, the conservation, maintenance and operation of its facilities and properties and the payment of the principal and interest on its notes, bonds, or other obligations; provided, however, that prior to putting into effect any increase in rates the Authority shall give at least a sixty-day notice of such increase to all customers who will be affected.

The Authority's assets include wholly owned and ownership interests in a variety of coal, natural gas, nuclear, hydro, biomass, landfill and solar generating units totaling 5,112 megawatts (MW) of summer power supply peak capability. This consists of 3,500 MW of coal-fired capacity, 1,117 MW of natural gas and oil capacity, 322 MW of nuclear capacity, 142 MW of hydro capacity, 29 MW of landfill methane gas capacity and 2 MW of solar capacity. The Authority implemented a plan in 2018 to un-idle Cross Unit 2 which was temporarily idled on March 1, 2017. In addition to its generation assets, the Authority may purchase from, sell to or exchange with other bulk electric suppliers additional capacity and energy in order to maximize the efficient use of generating resources, reduce operating costs and increase operating revenues. The Authority also operates an integrated transmission system which includes lines owned by the Authority as well as those owned by Central Electric Power Cooperative Inc. ("Central"), the Authority's largest wholesale customer.

OVERVIEW OF THE FINANCIAL STATEMENTS

This discussion serves as an introduction to the basic financial statements of the Authority to provide the reader with an overview of the Authority's financial position and operations. As discussed in the Notes to the Financial Statements (Note 1 - A "Reporting Entity"), the financial statements include the accounts of the Lake Moultrie and Lake Marion Regional Water Systems.

The Statements of Net Position – Business – Type Activities summarize information on the Authority's assets, deferred outflows of resources, liabilities, deferred inflows of resources and net position.

The operating results of the Authority are presented in the Statements of Revenues, Expenses and Changes in Net Position – Business – Type Activities. Revenues represent billings for electricity and wholesale water sales. Expenses primarily include operating costs and debt service related charges.

The Statements of Cash Flows – Business – Type Activities are presented using the direct method. This method provides broad categories of cash receipts and cash disbursements related to cash provided by or used in operations, non-capital related financing, capital related financing and investing activities.

The Notes are an integral part of the Authority's basic financial statements and provide additional information on certain components of the financial statements.

FINANCIAL CONDITION OVERVIEW

The Authority's Statements of Net Position as of December 31, 2018, 2017 and 2016 are summarized below:

		2018		2017		2016
				(Thousands)		
ASSETS & DEFERRED OUTFLOWS OF RESOURCES						
Capital assets	**$**	**5,056,884**	$	4,832,022	$	8,214,787
Current assets		**1,726,338**		2,618,394		2,779,166
Other noncurrent assets		**5,642,659**		5,510,276		1,244,276
Deferred outflows of resources		**239,411**		239,722		271,595
Total assets & deferred outflows of resources	**$**	**12,665,292**	$	13,200,414	$	12,509,824
LIABILITIES & DEFERRED INFLOWS OF RESOURCES						
Long-term debt - net	**$**	**7,355,557**	$	7,897,142	$	8,134,916
Current liabilities		**700,887**		863,865		916,567
Other noncurrent liabilities		**1,345,046**		1,182,967		1,185,935
Deferred inflows of resources		**966,279**		1,135,173		242,070
Total liabilities & deferred inflows of resources	**$**	**10,367,769**	$	11,079,147	$	10,479,488
NET POSITION						
Net investment in capital assets	**$**	**1,955,185**	$	1,523,505	$	1,168,907
Restricted for debt service		**7,322**		32,430		39,158
Restricted for capital projects		**280**		1,284		1,663
Unrestricted		**334,736**		564,048		820,608
Total net position	**$**	**2,297,523**	$	2,121,267	$	2,030,336
Total liabilities, deferred inflows of resources & net position	**$**	**12,665,292**	$	13,200,414	$	12,509,824

2018 COMPARED TO 2017

The primary changes in the Authority's financial condition as of December 31, 2018 and 2017 were as follows:

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

Total assets and deferred outflows of resources decreased $535.1 million during 2018 due to decreases of $892.1 million in current assets and $0.3 million in deferred outflows of resources. These decreases were offset by increases of $224.9 million in capital assets and $132.4 million in other noncurrent assets.

The increase in capital assets of $224.9 million was due to net construction work in progress additions of $253.6 million partially offset by a net decrease in utility plant of $26.9 million. The increase resulted from additions to solid waste landfills, the Rainey Generating Station's contract service agreement and the Pomeria-Orangeburg transmission line.

The decrease in current assets of $892.1 million was primarily due to decreases in unrestricted cash and investments as well as restricted cash and investments of $522.7 million and $162.4 million, respectively. These decreases were for debt service payments, funding the current year cash defeasances and capital expenditures. Also contributing were decreases of $183.4 million in fossil fuel inventory primarily due to lower coal purchases during 2018, $43.2 million in prepaid expenses and other current assets largely due to the current year amortization of a portion of the remaining balance of assets from a cancelled coal-fired generation project in Florence County, South Carolina. These decreases were offset by an increase in regulatory assets – nuclear of $14.4 million. The remaining $5.2 million was an increase resulting from the net change in receivables, materials inventory, nuclear fuel and interest receivable.

The increase in other noncurrent assets of $132.4 million was primarily due to an increase in the regulatory asset for OPEB of $138.6 million as a result of implementation of GASB 75.

LIABILITIES, DEFERRED INFLOWS OF RESOURCES & NET POSITION

Liabilities & deferred inflows of resources decreased $711.4 million due to decreases of $541.6 million in long-term debt, $163.0 million in current liabilities and $168.9 million in deferred inflows of resources. These increases were offset by increases of $162.1 million in other noncurrent liabilities.

Net long-term debt decreased $541.6 million primarily due to a cash defeasance of $357.7 million of bonds as well as $66.1 million for transfers to current portion of long-term debt. Unamortized debt discounts and premiums decreased $30.4 million for amortization of discounts and premiums and $13.9 million in removals from defeasance activity. Further decreases were provided by transfers of $76.2 million of long-term revolving credit agreements to short-term revolving credit agreements.

The decrease in current liabilities of $163.0 million was due to decreases in short-term revolving credit agreements of $132.8 million and accounts payable of $73.4 million. These decreases were offset by increases of $14.9 million in current portion of long-term debt and $29.4 million in commercial paper.

The increase in other noncurrent liabilities of $162.1 million was primarily due to the increase in the OPEB liability of $158.2 million recorded as a result of the implementation of GASB 75.

Deferred inflows of resources decreased $168.9 million largely due to amortization of $165.9 million of the Regulatory Inflows - Toshiba Settlement to align with utilizing settlement funds to fund the current year debt defeasances.

The increase in net position of $176.3 million was mainly due to increases in net investment in capital assets of $431.7 million. Offsets to these increases were decreases in unrestricted of $229.3 million as well as decreases in restricted for debt service of $25.1 million due to changes in accrued interest on long-term debt and reductions in the bond and debt service funds.

2017 COMPARED TO 2016

The primary changes in the Authority's financial condition as of December 31, 2017 and 2016 were as follows:

ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

Total assets and deferred outflows of resources increased $690.6 million during 2017 due to increases of $4.266 billion in other noncurrent assets. These increases were offset by decreases of $3.383 billion in capital assets, $160.8 million in current assets and $31.9 million in deferred outflows of resources.

The decrease in capital assets of $3.383 billion was primarily due to the reclassification of impaired nuclear assets from construction work in progress (CWIP) of $4.211 billion to a regulatory asset as a result of the suspension of construction of Summer Nuclear Units 2 and 3. These decreases were offset by increases in utility plant of $248.5 million and CWIP of $743.0 million.

The decrease in current assets of $160.8 million was due to a decrease of $112.1 million in fossil fuel inventory primarily due to lower coal purchases during 2017. Prepaid expenses and other current assets decreased $31.9 million primarily due to the current year amortization of a portion of the remaining balance of assets from a cancelled coal-fired generation project in Florence County, South Carolina. The remaining $16.8 million was a decrease resulting from the net change in receivables, materials inventory, nuclear fuel and interest receivable.

The increase in other noncurrent assets of $4.266 billion was primarily due to the reclassification of impaired nuclear CWIP to a regulatory asset as a result of the suspension of construction of Summer Nuclear Units 2 and 3.

The decrease in deferred outflows of resources of $31.9 million was largely due to the decrease of $21.7 million in unamortized loss on refunded and defeased debt, which resulted from amortization in 2017. Also contributing was pension related deferred outflows of $10.5 million from the Authority reporting its share of pension deferrals. Other changes resulted in a $300,000 increase.

LIABILITIES, DEFERRED INFLOWS OF RESOURCES & NET POSITION

Liabilities & deferred inflows of resources increased $599.7 million due to increases of $893.1 million in deferred inflows of resources. These increases were offset by decreases of $237.8 million in long-term debt-net; $52.7 million in current liabilities; and $3.0 million in other noncurrent liabilities.

Net long-term debt decreased $237.8 million due to a $157.1 million cash defeasance of bonds as well as $43.1 million for transfers to current portion of long-term debt. Unamortized debt discounts and premiums decreased $36.5 million for amortization of discounts and premiums and $5.7 million in removals from refunding activity. Somewhat offsetting this was a net increase of $1.5 million on the long-term revolving credit agreement due to current year draws and increase in accretion of $3.1 million on mini bonds.

The decrease in current liabilities of $52.7 million was due to decreases in commercial paper of $255.4 million and the current portion of long-term debt of $85.5 million. These decreases were offset by increases of $219.0 million in short-term revolving credit agreements and $70.7 million in accounts payable. Further reductions of $1.5 million were due to the residual changes in the other accounts in this category.

The decrease in other noncurrent liabilities of $3.0 million was due to a lower asset retirement obligation of $9.9 million. Partially offsetting this were increases in pension liabilities of $13.8 million. Net decreases of $6.9 million among the remaining accounts make up the residual variance.

Deferred inflows of resources increased $893.1 million due to recording of an $898.2 million regulatory deferred inflow for the Toshiba Settlement and increases of $8.3 million in nuclear decommissioning costs from market value adjustments, amortization and interest accruals associated with decommissioning funds. Partially offsetting these increases were $4.6 million lower accumulated increase in fair value of hedging derivatives and pension related deferred inflows of $8.8 million from the Authority's share of pension deferrals.

The increase in net position of $90.9 million was mainly due to increases in net investment in capital assets of $354.6 million. Partially offsetting these increases were decreases in unrestricted of $256.6 million as well as decreases in restricted for debt service of $6.7 million due to changes in accrued interest on long-term debt and reductions in the bond and debt service funds. Further reductions of $400,000 were due to the residual changes in the other accounts in this category.

RESULTS OF OPERATIONS

Santee Cooper's Statements of Revenues, Expenses and Changes in Net Position for the years ended December 31, 2018, 2017 and 2016 are summarized as follows:

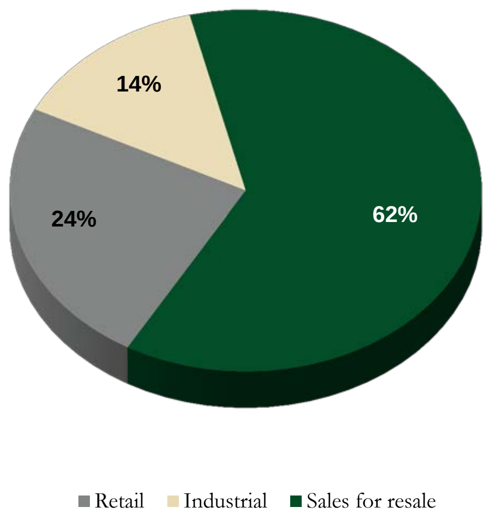
	2018	2017	2016
		(Thousands)	
Operating revenues	$ 1,806,620	$ 1,756,983	$ 1,745,657
Operating expenses	1,400,061	1,357,171	1,374,942
Operating income	406,559	399,812	370,715
Interest expense	(365,805)	(260,909)	(229,177)
Costs to be recovered from future revenue	(4,286)	(4,339)	(6,708)
Other income (expense)	157,185	(25,882)	(27,092)
Capital contributions & transfers	(17,397)	(17,751)	(19,192)
Change in net position	$ 176,256	$ 90,931	$ 88,546
Net position - beginning of period as previously reported	2,121,267	2,030,336	1,941,790
Ending net position	$ 2,297,523	$ 2,121,267	$ 2,030,336

2018 COMPARED TO 2017

OPERATING REVENUES

As compared to 2017, operating revenues increased $49.6 million (3%) primarily due to higher energy sales (4%) largely resulting from cold weather in January due to winter storm Grayson. Also contributing to the increase in operating revenues were higher wholesale demand and fuel rates. Somewhat offsetting these increases were lower rates from the Central Cost of Service largely due to higher usage and lower overall non-fuel operating and maintenance costs. Energy sales for 2018 totaled approximately 23.7 million megawatt hours (MWhs) as compared to approximately 22.8 million MWhs for 2017.

2018 Revenues from Sales of Electricity*
by Customer Class

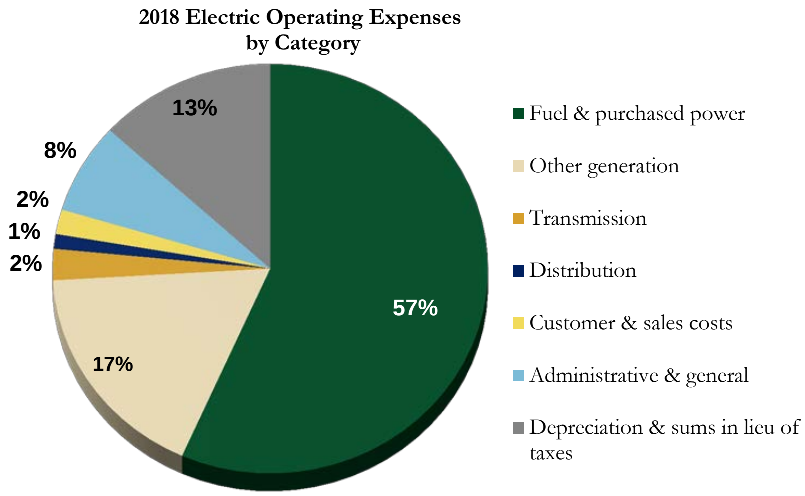


		2018		2017		2016
Revenues from Sales of Electricity*				(Thousands)		
Retail	**$**	**428,820**	$	407,752	$	406,246
Industrial		**245,117**		235,068		234,463
Sales for resale		**1,106,826**		1,089,472		1,080,399
Totals	**$**	**1,780,763**	$	1,732,292	$	1,721,108

*Excludes interdepartmental sales of $555 for 2018, $530 for 2017 and $524 for 2016.

OPERATING EXPENSES

Operating expenses for 2018 increased $42.3 million (3%) as compared to 2017. The main drivers were fuel cost and purchased power expense which increased by $32.8 million due to higher kWh sales, higher natural gas prices and a shift in generation mix. Also contributing to the increase in operating expenses were other generation costs of $14.4 million from: contract services primarily from Fluor charges to maintain Summer Nuclear Units 2 and 3 and a higher number of outages than prior year; and Summer nuclear expenses which resulted from higher labor costs due to the absorption of Summer Nuclear Units 2 and 3 employees, as well as a prior year Department of Energy reimbursement for spent fuel movement. Somewhat offsetting these increases were lower sales promotion of $6.7 million from higher accrual of Santee Cooper Economic Development Investment Fund and Site Readiness Funds in the prior year.



		2018		2017		2016
Electric Operating Expenses				(Thousands)		
Fuel & purchased power	**$**	**793,456**	$	760,696	$	775,737
Other generation		**239,155**		224,748		238,912
Transmission		**33,524**		32,762		33,767
Distribution		**18,275**		15,379		15,865
Customer & sales costs		**20,311**		28,112		26,636
Administrative & general		**99,324**		105,647		98,006
Depreciation & sums in lieu of taxes		**189,795**		184,203		180,725
Totals	**$**	**1,393,840**	$	1,351,547	$	1,369,648

NET BELOW THE LINE ITEMS

- Other income increased $183.1 million mainly from the amortization of the regulatory inflows – Toshiba Settlement to align with the use of the funds from the Toshiba Settlement Agreement to fund debt defeasance and capital expenditures.

- Interest expense for 2018 was $104.9 million higher primarily due to 2017 cessation of capitalized interest associated with the suspension of Summer Nuclear Units 2 and 3.

- Capital contributions and transfers represent dollars paid to the State. This payment, which is based on a percentage of total budgeted revenues was in-line with the prior year.

2017 COMPARED TO 2016

OPERATING REVENUES

As compared to 2016, operating revenues increased $11.3 million (1%) primarily due to higher wholesale demand, fuel and energy-related fixed cost rates as well as the retail base rate adjustments that went into effect April 1, 2017. Impacts between the 2016 and 2017 Central Cost of Service adjustments also added to this increase. Lower energy sales (4%) resulting from milder weather and the combined reduced load from industrial and wholesale customers somewhat offset these increases. Energy sales for 2017 totaled approximately 22.8 million megawatt hours (MWhs) as compared to approximately 23.7 million MWhs for 2016.

OPERATING EXPENSES

Operating expenses for 2017 decreased $17.8 million (1%) as compared to 2016. The main driver was fuel and purchased power expense which decreased by $15.0 million due to lower kWh sales, higher commodity prices in the prior year and a shift in economic dispatch due to lower prices in the energy markets. Also contributing were decreases in non-fuel generation of$14.2 million from contract services and materials primarily due to a planned spring outage at Winyah Generating Station not occurring in 2017. Somewhat offsetting these decreases were higher administrative and general costs of $7.6 million from labor and contract services. Other smaller variances $3.8 million netted an increase and were spread among the remaining cost categories.

NET BELOW THE LINE ITEMS

- Other income increased by $1.2 million primarily due to an increase in the fair value of investments and a decrease in the loss realized on sale of coal due to the remainder of the Jefferies Generating Station coal sale being finalized in 2016.

- Interest expense for 2017 was $31.7 million higher primarily due to a current year decrease in capitalized interest associated with Summer Nuclear Units 2 and 3.

- Cost to be recovered (“CTBR”) decreased $2.4 million.

- Capital contributions and transfers represent dollars paid to the State. This payment, which is based on a percentage of total budgeted revenues, decreased by $1.4 million due to lower revenues in the 2017 budget as compared to the 2016 budget.

ECONOMIC CONDITIONS

The Authority and the electric industry continue to face economic and industry challenges that impact the competitiveness and financial condition of the utility. As market conditions fluctuate, the Authority's mission continues to be to deliver low-cost and reliable electricity and water to its customers.

To address these challenges, the Authority has developed business growth initiatives that revolve around four strategic initiatives - marketing, product development, project management and competitive rates. The Authority is marketing industrial and commercial properties that are served directly by the Authority and its Electric Cooperative partners and municipal customers. Product development activities include the creation and/or improvement of industrial properties, the acquisition of property, expansion of infrastructure into funding for industrial properties, and/or constructing buildings for industrial use. Since June 2012, the Authority has invested over $93.5 million throughout South Carolina in product development activities through low-interest revolving loans to public entities. In addition, the Authority created two additional funds to further improve the readiness of industrial sites in the Electric Cooperatives' and municipal customers' territories, directly or indirectly served by Santee Cooper. Approvals through 2018 total more than $11.0 million from the municipal site readiness fund and over $23.0 million from the South Carolina Power Team Site Readiness Fund. Funding for these programs was extended through 2020 by the Authority's Board of Directors.

In May 2015, Swedish automaker Volvo announced that it would build its first U.S. factory in Berkeley County, S.C., spending up to $500.0 million on a plant with an initial capacity of 100,000 vehicles a year. The Authority worked with the State, Berkeley County and the Electric Cooperatives to recruit Volvo to this site. The manufacturing site is served by Edisto Electric Cooperative, a member of Central. In September 2017 Volvo announced a $500.0 million expansion of the plant that included an additional 1,900 jobs bringing the total capital investment to $1.0 billion and 3,900 jobs. Volvo began full production of their first American made car in 2018 and Volvo is on schedule to begin production from the announced expansion in 2021. The Authority owns approximately 3,900 acres adjacent to the Volvo site and is currently developing the property according to the master plan as an industrial park. The Volvo project, as well as the industrial park development, is proceeding as planned.

The Authority's commitment to economic development efforts along with the State and support of its Electric Cooperatives also brought additional announcements of business growth projects during 2018, including JW Aluminum's expansion of its current operations and Evanesce Packaging Solutions, Inc. plans to locate its first large-scale projection operations in the United States in Colleton County, South Carolina.

The Authority's largest customer, Central, accounted for 58.6 percent of sales revenues in 2018. Central provides wholesale electric service to each of the 20 distribution cooperatives which are members of Central pursuant to long-term all requirements power supply agreements. In September 2009, Central and the Authority entered into an agreement ("September 2009 Agreement") that, among other things, allowed Central to transition the portion of power and energy requirements of the five former Saluda members, the ("Upstate Load"), directly connected to the transmission system of Duke Energy Carolinas, LLC to another supplier. In January 2013, Central began transitioning the Upstate Load to Duke Energy Carolinas, a subsidiary of Duke Energy Corporation, ("Duke"). The load transition was complete on January 1, 2019 and amounted to approximately 900 MW. Nothing precludes the Authority from serving this load when the Duke agreement ends on December 31, 2030.

In May 2013, the Authority and Central agreed to extend their termination rights as noted in the September 2009 Agreement until December 31, 2058, ("Coordination Agreement"). Under the Coordination Agreement 10-year rolling notice provision, for a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. Central has entered into requirement agreements with all 20 of its member cooperatives that extend through December 31, 2058 and obligate those members to pay their share of Central's costs, including costs paid under the Coordination Agreement. Certain matters between the Authority and Central relating to the nuclear project are the subject of litigation, however, the parties continue to conduct business pursuant to the terms of the Coordination Agreement.[1]

[1] See Footnote 10 – Legal Matters for a description of a litigation under the subheading *"Jessica S. Cook et al. v. Santee Cooper, Santee Cooper's Board of Directors (certain former and current Directors named), SCE&G, Palmetto Elec. Coop., & Central Elec. Pwr. Coop"* for a description of Central's cross-claim against the Authority seeking, among other things, (i) a declaratory judgment that Santee Cooper breached the Coordination Agreement and (ii) an award of 70% of the lump sum payment Santee Cooper received from Citibank, N.A. under the Assignment and Purchase Agreement described under Footnote 7 – Summer Nuclear Station – Summer Nuclear Units 2 and 3.

LEGISLATIVE MATTERS

On June 29, 2018, the South Carolina General Assembly ("General Assembly") ratified a State budget for FY 2018-2019, which runs from July 1 to June 30. The State budget included a proviso addressing Santee Cooper, also known as the South Carolina Public Service Authority. Part 1B Proviso 117.162 established a Public Service Authority Evaluation and Recommendation Committee ("Evaluation Committee") comprised of the Governor, four SC Senators and four SC House Members.

An objective of the Evaluation Committee is to determine a manner in which the General Assembly may best protect ratepayers and taxpayers in regard to Santee Cooper. This includes analyzing whether selling Santee Cooper is in the best interest of the State and Santee Cooper's customers or whether Santee Cooper should be retained by the State.

From August 7, 2018 to February 6, 2019, the Evaluation Committee held six meetings. The Evaluation Committee hired ICF International, Inc. ("ICF") to assist the Evaluation Committee with its review and to facilitate a process to receive and evaluate non-binding indicative bid proposals for the full purchase of Santee Cooper, to receive alternative proposals, and to conduct a valuation of Santee Cooper. On February 1, 2019, ICF issued its report to the Evaluation Committee. The SC General Assembly is now expected to continue its review of Santee Cooper which includes, among other things, the consideration of various alternatives for Santee Cooper such as managing or restructuring Santee Cooper or selling portions of its assets.

On February 21, 2019, the South Carolina Senate announced the creation of the Select Committee on Santee Cooper. The Senate has not yet set a date for the first meeting of the Select Committee.

The General Assembly is scheduled to meet from January 8, 2019 to May 9, 2019. Legislation may be introduced that impacts Santee Cooper's operations. Santee Cooper will be educating and informing the General Assembly of the impact of any relevant legislation that may impact its customers and operations.

CAPITAL IMPROVEMENT PROGRAM

The purpose of the capital improvement program is to continue to meet the energy and water needs of the Authority's customers with economical and reliable service. The Authority's three-year budget for the capital improvement program approved in 2018, 2017 and 2016 was as follows:

Approved in:	**2018**	2017	2016
	Budget 2019-21	Budget 2018-20	Budget 2017-19
Capital Improvement Expenditures		(Thousands)	
Environmental compliance [1]	**$ 188,699**	$ 333,534	$ 582,922
General improvements and Other [2]	**559,519**	533,021	1,048,474
Summer Nuclear Units 2 and 3 [3]	**0**	6,994	2,222,554
Totals	**$ 748,218**	$ 873,549	$ 3,853,950

(1) The Coal Combustion Residual and Steam Electric Effluent Limitation regulations are undergoing agency review and court challenges.
Given the significant uncertainty about the outcome and eventual requirements, Budget 2019-21 does not reflect all potential costs at this time.

(2) Other includes Camp Hall and renewables.

(3) Construction suspended in July 2017. Budget, 2018-20 reflects ramp down cost estimates in year 2018.

As determined by the Authority, the capital improvement program will be funded from revenues, additional revenue obligations, commercial paper, internal funding sources and other short-term obligations.

Summer Nuclear Units 2 and 3

Engineering, Procurement and Construction Agreement and Project History. On May 23, 2008, SCE&G, acting for itself and as agent for the Authority (together, the "Owners"), entered into an Engineering, Procurement, and Construction Agreement (the "EPC Agreement"), with a consortium consisting of Westinghouse and Stone & Webster, Inc. (the "Consortium"). Pursuant to the EPC Agreement, the Consortium would supply, construct, test, and startup two 1,117 MW nuclear generating units utilizing Westinghouse's AP 1000 standard plant design. The EPC Agreement included substantial completion dates of April 2016 and January 2019 for Summer Nuclear Units 2 and 3 (the "Project" or "Summer Nuclear Units 2 and 3"), respectively.

On October 20, 2011, the Owners entered into a Design and Construction Agreement specifying an Authority ownership interest of 45% in each of Summer Nuclear Unit 2 and Summer Nuclear Unit 3. Among other things, the Design and Construction Agreement allowed either or both parties to withdraw from the project under certain circumstances. The Authority and SCE&G also entered into an Operating and Decommissioning Agreement on October 20, 2011 with respect to the two units. Both the Design and Construction Agreement and the Operating and Decommissioning Agreement defined the conditions under which the Authority or SCE&G could convey an undivided ownership interest in the units to a third party.

On December 30, 2011 the Nuclear Regulatory Commission ("NRC") approved the AP 1000 standard plant design (DCD Revision 19) for Summer Nuclear Units 2 and 3. On March 30, 2012, the NRC issued the Combined Construction and Operating Licenses (the "COLs") with certain conditions for Summer Nuclear Units 2 and 3.

On October 27, 2015, the Owners executed a Limited Agency Agreement that appointed SCE&G to act as the Authority's agent in connection with an amendment to the EPC Agreement. The amended EPC Agreement, which became effective on December 31, 2015, included, among other things, an irrevocable option (the "Fixed Price Option") which SCE&G executed on behalf of the Owners on July 1, 2016, to further amend the EPC Agreement to fix the total amount to be paid to the Consortium for its entire scope of work on the Project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (Authority's 45% portion being $2.737 billion), subject to adjustment for amounts paid since June 30, 2015. The amended EPC Agreement also provided for Toshiba Corporation, Westinghouse's parent company, to reaffirm its guaranty of Westinghouse's payment obligations (the "Guaranty") and revised the substantial completion dates of Units 2 and 3 to August 31, 2019 and August 31, 2020, respectively.

Toshiba Financial Difficulties/Westinghouse Bankruptcy. In late 2015, following disclosures regarding its operating and financial performance and near-term liquidity, Toshiba Corporation's ("Toshiba") credit ratings declined to below investment grade. Pursuant to the terms of the EPC Agreement, the Owners obtained payment and performance bonds from Westinghouse in the form of standby letters of credit totaling $45.0 million (the Authority's 45% share is $20.3 million).

On December 27, 2016, Toshiba announced financial difficulties related to the goodwill associated with the Westinghouse acquisition of Stone & Webster. Following several announcements and related media reports, on February 14, 2017, Toshiba, the parent company of Westinghouse and the guarantor of its financial and performance obligations with respect to the EPC Agreement, announced that it preliminarily recorded a multi-billion dollar impairment loss associated with the construction of Summer Nuclear Units 2 and 3 and the two additional AP1000 units being constructed by Westinghouse for another company in the United States (Plant Vogtle). The impaired goodwill resulted from Westinghouse's analysis that the cost to complete the four Westinghouse AP1000 new nuclear plants in the United States would far surpass the original estimates for construction. Toshiba attributed the cost overruns to, among other things, higher labor costs arising from lower than anticipated work efficiency and the inability to improve such work efficiency over time. On April 11, 2017 Toshiba released their unaudited quarterly securities report for the period covering April 1, 2016 to December 31, 2016 showing a loss of 532 billion Yen (US $4.800 billion).

On March 29, 2017, Westinghouse and 29 affiliated companies filed a Petition pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court for the Southern District of New York. This Petition allowed for a transition and evaluation period during which the Owners would assess information provided by Westinghouse and determine the most prudent path forward for the project. After the filing of the bankruptcy proceeding, the Owners entered into negotiations with Toshiba Corporation for the purpose of acknowledging and defining Toshiba's obligation under Toshiba's May 23, 2008 Guaranty and establishing a schedule for the full payment of that obligation to the Owners.

Toshiba Settlement Agreement (the "Settlement Agreement" or "Toshiba Settlement Agreement"). On July 27, 2017 the Owners and Toshiba entered into a Settlement Agreement that provided, among other things: A) Toshiba's agreement that it would pay the Guaranty obligation in the amount of $2.168 billion (Authority's 45% share was $975.6 million) , in accordance with a schedule set forth in the Settlement Agreement; B) Toshiba's agreement that payment of the Guaranty obligation and related payment schedule would not be dependent on whether one or both of the two units are completed; C) Toshiba's agreement that the Owners' were not releasing any claims or rights against Westinghouse; D) Toshiba's agreement not to subordinate the Guaranty obligations except to working capital lenders and other relationships necessary to continue and enhance its financial condition; E) Toshiba, Westinghouse, and the owners of the Vogtle and Summer Nuclear AP1000 Project's agreement to become parties to a consent order in the Bankruptcy Court that approves assignment by Toshiba to the Summer Nuclear and Vogtle owners of all rights to the non-U.S. assets in the Westinghouse family of companies owned by Toshiba, any of Toshiba's rights against Westinghouse relating to loans, and similar receivables; F) agreement by the parties to the Settlement Agreement to work towards an expeditious sale of Westinghouse; G) the Owners' agreement that the distribution proceeds received from the Westinghouse bankruptcy would be a credit against the Guaranty; and H) the Owners' agreement not to exercise remedies of the Guaranty, absent a default, until September 2022.

On September 1, 2017, the Owners filed two proofs of claim in unliquidated amounts in the Westinghouse Bankruptcy Proceeding.

On September 27, 2017, the Owners entered into an Assignment and Purchase Agreement under which they sold and assigned rights to receive payment under the Settlement Agreement and rights, duties and obligations arising under two proofs of claim filed in the Westinghouse Bankruptcy Proceeding to Citibank, N.A., in exchange for a purchase price in the amount of $1,847,075,400. The Authority's share of the purchase price was $831,183,930. Excluded from the sale was the first $150.0 million (Authority's 45% share was $67.5 million) payment under the Toshiba Settlement Agreement, which was received by the Owners.

On January 2, 2018, the Owners entered into Amendment No. 1 of the Settlement Agreement and Amendment No. 1 of the Assignment and Purchase Agreement, which amendments had the effect of capping at $60.0 million the Owners' current obligation to reimburse Citibank, N.A. for payments from the Westinghouse Estate that had the effect of reducing mechanics liens at the site (Authority's 45% share is $27.0 million).

Developments in the Westinghouse Bankruptcy Proceeding. On March 28, 2018, the United States Bankruptcy Court for the Southern District of New York issued its order confirming Westinghouse Electric Company's Modified Second Amended Joint Chapter 11 Plan of Reorganization. The plan provides for, among other things, the sale of Westinghouse to Brookfield Business Partners, L.P. for $4.6 billion, a sale that closed on August 1, 2018.

The plan also provides for payment to allowed general unsecured creditors in an amount equal to the lesser of (i) its pro rata share of certain funds; or (ii) 100% of the amount of the allowed claim. Claims by those providing materials and services at the site have been classified under the plan as general unsecured creditors. Payments from the Westinghouse Estate that have the effect of reducing mechanics liens at the site have the potential to increase amounts that must be paid by the Authority to reimburse CITIBANK.

On December 15, 2018, an initial distribution was made to general unsecured creditors equaling about 25% of the allowed amount of each claim. The total amount of the allowed general unsecured claim pool is not currently known, but the size of that pool plays a significant factor in determining the amount each allowed general unsecured creditor will be paid. It is currently anticipated that allowed general unsecured creditors will receive full or substantially full payment; however, that cannot yet be confirmed as payment of allowed general unsecured claims will not be completed until the later part of 2019.

Cost to Complete and Construction Suspension. Beginning in late March 2017, the Owners formed an independent team led by the SCE&G construction manager to undertake a rigorous Estimate-to-Complete ("ETC") validation process, including the costing/scheduling expertise of High Bridge Associates and the expertise of AECOM Energy & Construction Inc. in the area of salvage, site restoration and preservation. The process began with gathering and validating information and data received from Westinghouse and Fluor, and creating a new schedule model using Owner, Fluor and Westinghouse schedules. On a parallel track and during the same time frame, the Authority retained nFront Consulting LLC to undertake an assessment of the projected cost of power from Summer Nuclear Units 2 and 3 if completed, compared to other alternatives in meeting future energy needs of the Authority.

Based upon the ETC validation process, management of the Authority found the results of the ETC validation process adequate to determine the viability of the Project; those results estimating the schedule to complete Unit 2 would be delayed at least 40 months beyond the August 2019 contract completion date, and the estimated schedule to complete Unit 3 would be delayed at least 43 months beyond the August 2020 contract completion date. Based on both studies, the estimated cost to the Authority to complete both units, including construction period interest, increased from $8.100 billion to $11.400 billion, and the cumulative average system cost of power would be substantially higher if one or both units were completed as compared to suspending construction.

On July 31, 2017, the Board of Directors of the Authority, by Resolution authorized the President and CEO, among other things, to immediately begin taking those actions necessary to wind-down and suspend construction on the two 1,100 MW nuclear units at the Summer Nuclear site in Fairfield County, and protect and preserve both the site and related plant components and equipment. That resolution contemplated the establishment of a Project construction cessation plan and process of seeking additional support for the Project to remain in place for up to a period of one year from the date of the Resolution. There are currently no legal or regulatory requirements for the site to be maintained or restored to its original condition. As such, no removal or restoration costs have been accrued.

Upon suspending the Project, and in accordance with GASB 62, the Authority ceased capitalizing interest expense on the debt incurred to fund the Project as of July 31, 2017.

As of December 31, 2017 the Owners identified assets that could be utilized at Summer Nuclear Unit 1, consisting of various buildings and structures totaling $44.8 million (Authority's 45% share). These assets were transferred to Summer Nuclear Unit 1, and as a result in the difference of ownership percentage, the assets were recorded on Unit 1 at $32.8 million (Authority's 33.33% share) and a receivable in the amount of $12.0 million was recorded on the Authority's books. In April 2018, the Authority received payment of $11.4 million to complete the transaction for the assets transferred to Summer Nuclear Unit 1. As of December 31, 2018, the Owners agreed to a reduction in the Authority's ownership of the switchyard at the Summer Nuclear site from 32.19% to 27.08%. As a result, a receivable in the amount of $2.7 million was recorded on the Authority's books. In addition, the Authority constructed transmission assets concurrently with the Project. These assets, which include switchyard costs, total $212.8 million at December 31, 2018, and will be utilized to enhance the Authority's transmission system.

Impairment of Project Assets. With suspension of the Project construction, the Authority sought additional project partners and financial support. South Carolina's Governor indicated that he contacted a number of companies inquiring about their interest in purchasing or partnering in the Project. As of December 31, 2017 the Authority had not received or been informed of any proposal to purchase the Project or partner in the Project. As such an evaluation was conducted to determine whether the assets were impaired. In accordance with GASB 42, the assets are impaired based on A) the decline in service utility of the capital asset is large in magnitude and B) the event or change in circumstance is outside the normal life cycle of the capital asset. While the Project could be completed at some point in the future, the Authority had no near-term plans to complete the Project. Except for the assets described above that will be utilized at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the remaining Project assets, including the nuclear fuel, were determined to be impaired.

In addition to the lack of proposals by a third party to purchase or partner in the Project, the Authority also considered several other items in order to determine the fair value of the impaired assets.

The AP1000 is a new technology. There are no completed AP1000s in the United States and only two other units under construction in the United States. There was not an active liquid market for the purchase of these partially completed units.

SCE&G obtained several estimates of the salvage value of the remaining Project assets. The highest estimate was for approximately $150.0 million (Authority's share of this would be 45%). Westinghouse cited contractual provisions that it believes indicate that the Owners may not have unencumbered title to the proceeds of the sale of the assets. Should the sale of the assets move forward, a final determination regarding ownership of the sale proceeds might be delayed.

On December 27, 2017 SCE&G, based on the decision to abandon the Project, submitted a letter request to the NRC for approval to withdraw the COLs for Summer Nuclear Units 2 and 3. On January 8, 2018, the Authority submitted a letter in response to this request in which the Authority requested, among other things, that the NRC not take action for 180 days or until such time that the Authority could evaluate any risks it could incur by taking on the nuclear licenses.

Based on these considerations the Authority determined a fair value of zero as of December 31, 2018 for the non-fuel impaired Project assets.

With the suspension of construction of Summer Nuclear Units 2 and 3 the nuclear fuel material for the first core load of the units will no longer be needed or used in Units 2 and 3. Due to the nature of the Unit 2 and 3 fuel, it cannot be used as is at Summer Nuclear Unit 1. SCE&G performed an analysis to determine how this fuel might be disposed and the fair value of the fuel. The analysis considered both selling the fuel into the market and exchanging the fuel for material that can be used in Unit 1. SCE&G used estimated market prices as of December 31, 2017 obtained from nuclear fuel suppliers when estimating the value of the fuel. Using SCE&G's analysis the Authority had determined that the fair value of this fuel was 33.52% of the book value of the fuel, or $34.6 million (Authority's share), as of December 31, 2017. The remaining $68.5 million was written off as impaired.

Based on the results in determining the fair value, the write-off of Summer Nuclear Units 2 and 3 construction costs and nuclear fuel for the year ended December 31, 2017 totaled $4.211 billion.

During 2018 additional invoices related to Units 2 and 3 were received and other correcting entries were made to the Unit 2 and 3 costs. These amounts were part of the impaired assets and were charged to the Nuclear Regulatory Asset (See Footnote 1 – K - Other Regulatory Items). Market prices for Unit 2 and 3 fuel were estimated as of December 31, 2018 and based on these prices, no additional adjustments to the book value of the fuel were made.

2018 Developments Status of COLs. On January 28, 2019 the Authority Board approved a resolution authorizing the Interim President and CEO to consent to SCE&G's request to terminate the Summer Nuclear Units 2 and 3 COLs. That consent was conveyed to the Nuclear Regulatory Commission in a letter dated January 29, 2019. (See Footnote 15 - Subsequent Events.)

Reactor Coolant Pump Transfer to China. In February 2018, SCE&G and the Authority sold one reactor coolant pump planned for use in Summer Nuclear Unit 2 to Westinghouse for use in the China Project, Haiyang Unit 2. The Authority's 45% share of the proceeds was approximately $6.5 million and the resulting gain was recorded as a regulatory liability (See Footnote 1- K Other Regulatory Items.).

Sales Tax Audit and Proposed Assessment. On January 26, 2018 the SC DOR notified SCE&G that the sales and use tax returns for the Summer Nuclear 2&3 project have been assigned for a sales and use tax audit. During a meeting on February 8th, the DOR clarified its position that, because the VC Summer 2&3 project had been abandoned and the manufacturing facility was not completed and would not produce electricity, the materials for the Project were not tax-exempt and sales taxes were due on previously tax exempt purchases. On May 31, 2018, the SC DOR notified SCE&G that, since all of the information requested of SCE&G was not provided; a Proposed Notice of Assessment was generated. The full assessment, which was based on information obtained by the department, was for $421 million. On October 1, 2018 Santee Cooper's outside counsel submitted on Santee Cooper's behalf a Protest to Notice of Proposed Assessment Department File No. 020800475. As of December 31, 2018, Santee Cooper continues to dispute the position that sales taxes are due and owing.

Right of Entry; Maintenance, Preservation and Documentation Plan; and Warehoused Equipment Moved. On June 25, 2018, SCE&G and the Authority signed a Right of Entry Agreement allowing the Authority to begin implementation of a Maintenance, Preservation, and Documentation Plan (MPD) to preserve the equipment for the Project. The Authority contracted with Fluor Inc. to perform this scope of work to assess the equipment condition and to maintain the high value equipment. Fluor Inc. began this scope of work at the Project on July 2, 2018. Additionally, all assets stored in two large offsite warehouses were relocated to the Project site in 2018.

Switchyard True-Up. Included in the Summer Nuclear Units 2 and 3 transmission related assets that were not impaired were certain switchyard assets. During 2018 the parties determined that the ownership interest in these assets needed to be adjusted and began negotiating an agreement to adjust the percentages and true-up the charges. As of December 31, 2018 that adjustment was reasonably estimated and a receivable from SCE&G to the Authority in the amount of $2.7 million was recorded. The Authority expects to complete this effort in the second quarter of 2019.

Forbearance Agreement and Next Steps. On December 13, 2018, SCE&G and the Authority executed an agreement styled a "Forbearance Agreement" whereby SCE&G reaffirmed its irrevocable waiver of any and all rights in the Forbearance Assets, defined generally as Summer Nuclear Units 2 and 3; ancillary facilities; intellectual property; equipment and materials on-site and off-site including, without limitation assets, materials and equipment that are affixed to the real property at the site but are capable of being removed. Excluded from the definition of Forbearance Assets is the underlying real property; certain specifically identified assets excluded from the abandonment prior to December 31, 2017; substation and switchyard assets; the old NND Building and nuclear fuel. The Forbearance Agreement requires SCE&G seek, within 30 days of the execution of the agreement, approval of the Public Service Commission of South Carolina of the agreement and, during the same 30 day period, take reasonable efforts to obtain the release of any security interest or mortgage attached to the Forbearance Asset.

The execution of the Forbearance Agreement and its successful approval and implementation will set the foundation for possible domestic and international sales of equipment, commodities and plant components covered by the agreement.

Regulatory Accounting Treatment

Nuclear Asset Impairment. On January 22, 2018, the Board approved the use of regulatory accounting for the $4.211 billion impairment write down. The majority of the Project was financed with borrowed funds. For rate-making purposes, the Authority includes the debt service on these borrowed funds in its rates. As such, the impairment will be recorded as a regulatory asset and amortized through November 2056 to align with the associated debt principal payments. In the event the principal maturities change materially the amortization will be adjusted to better align with the new maturities. In 2018, there was a decrease of $8.3 million charged to the nuclear impairment regulatory asset for adjustments after year end 2017, as well as amortization of $4.9 million.

Post Project Suspension Interest Expense. On December 11, 2017 the Board issued a resolution authorizing the use of regulatory accounting to defer a portion of the post suspension Project interest. With the cessation of capitalized interest and the timing of the suspension the Authority would be unable to collect a portion of the post suspension Project interest in rates. The regulatory asset for post suspension nuclear interest totaled $37.1 million and will be amortized through November 2056 to align with the principal payments on the debt used to pay the interest.

Toshiba Settlement Agreement. The Board of Directors also approved a resolution dated December 11, 2017, authorizing using regulatory accounting to defer recognition of income from the Settlement Agreement. The Authority recorded a regulatory deferred inflow of $898.2 million. The deferred inflow will be amortized to align with the manner in which debt service is reduced as a result of using the proceeds.

The following table summarizes nuclear related regulatory items:

Regulatory Item	Classification	Original Amount	2018 Amortization	2018 Changes	2018 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($ 4.9 million)	($ 8.1 million)	$ 4.198 billion
Nuclear post-suspension interest	Asset	$ 37.1 million			$ 37.1 million
Toshiba Settlement Agreement	Deferred Inflow	$ 898.2 million	($ 176.6 million)	$ 10.7 million	$ 732.3 million

Financing Activities

Although there were no major financial transactions during 2018, the Authority entered into two cash defeasances whereby proceeds from the Toshiba Settlement Agreement were deposited into an Escrow Account to provide for the payment of principal of and interest on certain bonds maturing December 1, 2019 through December 1, 2043, respectively. The resulting transactions included the reduction of approximately $357.7 million in debt outstanding. The net debt service savings for the years impacted by the defeasance transactions are approximately $536.9 million.

Liquidity and Capital Resources

The Authority has significant cash flow from operating activities, access to capital markets, bank facilities and special funds deposit balances.

At December 31, 2018, the Authority had $1.200 billion of cash and investments, of which $949.9 million was available for liquidity purposes to fund various operating, construction, debt service and contingency requirements. Balances in the decommissioning funds totaled $214.3 million.

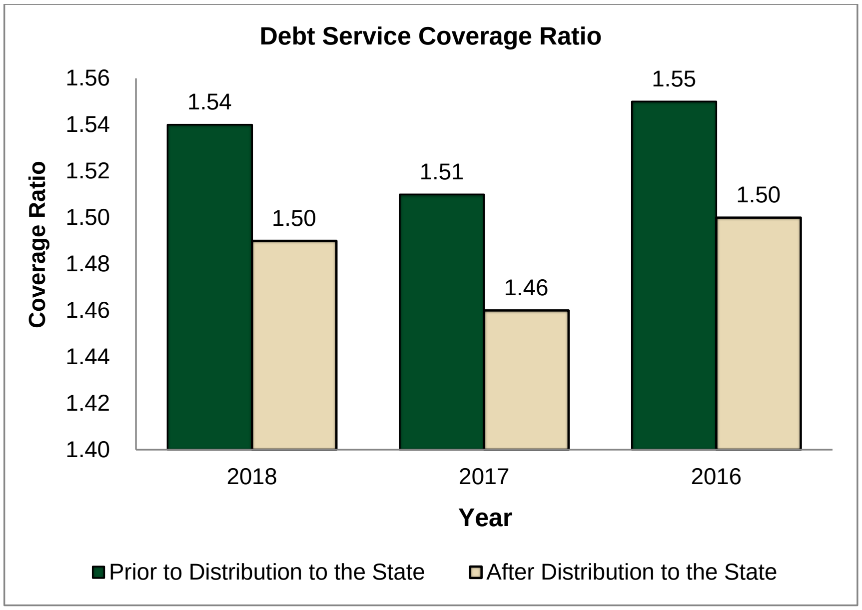
The Authority has entered into Reimbursement Agreements and secured irrevocable direct-pay letters of credit with two banks to support the issuance of commercial paper notes totaling $250.0 million as of December 31, 2018. As of December 31, 2018, the Authority had $173.9 million of commercial paper notes outstanding.

To obtain other funds if needed, the Authority has entered into Revolving Credit Agreements with each of Barclays Bank PLC, TD Bank, N.A., JP Morgan Chase Bank, N.A., and Wells Fargo Bank, N.A, respectively. These agreements allow the Authority to borrow up to a total of $850.0 million and expire at various dates in 2020 and 2021. At December 31, 2018, the Authority had borrowings totaling $111.5 million outstanding under the Revolving Credit Agreements.

Net cash used by the Authority during 2018 was $268.7 million. This decrease in cash was due to net cash used by non-capital and capital related financing activities of $536.7 million and $978.5 million, respectively. These decreases were partially offset by cash provided by operating and investing activities of $813.4 million and $433.1 million, respectively.

DEBT SERVICE COVERAGE

The Authority's debt service coverage (excluding commercial paper and other) for the years ended December 31, 2018, 2017 and 2016 is shown below:



BOND RATINGS

Bond ratings assigned by various agencies as of December 31, 2018, 2017 and 2016 were as follows:

Agency / Lien Level	**2018**	2017	2016
Fitch Ratings			
Revenue Obligations	**A-**	A+	A+
Commercial Paper[1]	**F1+**	F1/F1+	F1
Outlook	**Negative**	Stable	Stable
Moody's Investors Service, Inc.			
Revenue Obligations	**A2**	A1	A1
Commercial Paper[1]	**P-1**	P-1	P-1
Outlook	**Negative**	Stable	Stable
Standard & Poor's Rating Services			
Revenue Obligations	**A+**	A+	AA-
Commercial Paper[1]	**A-1**	A-1/A-1+	A-1
Outlook	**Negative**	Stable	Stable

[1] In 2017, the Authority entered into Direct Pay Letters of Credit issued by various banks supporting the commercial paper program. The banks issuing the Letters of Credit have various ratings assigned by the rating agencies.

BOND MARKET TRANSACTIONS FOR YEARS 2018, 2017 AND 2016

YEAR 2018

No Bond Market Transactions - South Carolina Public Service Authority did not issue any Revenue Bond Obligations in 2018.

YEAR 2017

No Bond Market Transactions - South Carolina Public Service Authority did not issue any Revenue Bond Obligations in 2017.

YEAR 2016

Revenue Obligations:	2016 Tax-exempt Refunding Series A	Par Amount:	$ 543,745,000
Purpose:	Refund a portion of the following: 2007 Series A, 2008 Series A, 2009 Refunding Series A, 2009 Series B, and 2014 Series A	Date Closed:	February 10, 2016
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.66 percent		
Revenue Obligations:	2016 Series M1 - Current Interest Bearing Bonds (CIBS)	Par Amount:	$ 33,282,500
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 19, 2016
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2016 Series M1 – Capital Appreciation Bonds (CABS)	Par Amount:	$ 8,860,200
Purpose:	To finance a portion of the Authority's ongoing capital program	Date Closed:	May 19, 2016
Comments:	Tax-exempt minibonds		
Revenue Obligations:	2016 Tax-exempt Refunding and Improvement Series B	Par Amount:	$ 508,705,000
Purpose:	To finance a portion of the Authority's ongoing capital program and refund a portion of the following: 2009 Series E	Date Closed:	July 20, 2016
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.75 percent		
Revenue Obligations:	2016 Taxable Series D	Par Amount:	$ 322,650,000
Purpose:	To retire certain Commercial Paper Notes and to finance a portion of the Authority's ongoing capital program	Date Closed:	July 20, 2016
Comments:	Taxable bonds with an all-in true interest cost of 2.45 percent		
Revenue Obligations:	2016 Tax-exempt Refunding Series C	Par Amount:	$ 52,400,000
Purpose:	Refund a portion of the following: 2006 Series C	Date Closed:	October 13, 2016
Comments:	Tax-exempt bonds with an all-in true interest cost of 3.11 percent		

REQUESTS FOR INFORMATION

This financial report is designed to provide a general overview of the South Carolina Public Service Authority's finances for all those with an interest in the South Carolina Public Service Authority's finances. Questions concerning any of the information provided in this report or requests for additional information should be addressed to Suzanne H. Ritter, Vice President and Controller, South Carolina Public Service Authority, P.O. Box 2946101, Moncks Corner, SC 29461-6106.

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Statements of Net Position - Business - Type Activities

South Carolina Public Service Authority
As of December 31, 2018 and 2017

		2018		2017
		(Thousands)		
ASSETS				
Current assets				
Unrestricted cash and cash equivalents	$	**475,601**	$	731,758
Unrestricted investments		**474,269**		740,777
Restricted cash and cash equivalents		**53,600**		71,338
Restricted investments		**18,666**		163,360
Receivables, net of allowance for doubtful accounts of $2,073 and $2,177 at December 31, 2018 and 2017, respectively		**225,636**		228,575
Materials inventory		**138,447**		132,859
Fuel inventory				
Fossil fuels		**123,859**		307,279
Nuclear fuel - net		**110,250**		107,420
Interest receivable		**2,308**		2,522
Regulatory Assets - nuclear		**14,419**		0
Prepaid expenses and other current assets		**89,283**		132,506
Total current assets		**1,726,338**		2,618,394
Noncurrent assets				
Restricted cash and cash equivalents		**5,247**		27
Restricted investments		**130,714**		135,654
Capital assets				
Utility plant		**7,678,064**		7,545,203
Long lived assets - asset retirement cost		**265,116**		265,116
Accumulated depreciation		**(3,933,151)**		(3,773,415)
Total utility plant - net		**4,010,029**		4,036,904
Construction work in progress		**1,017,170**		763,490
Other physical property - net		**29,685**		31,628
Investment in associated companies		**7,162**		6,587
Costs to be recovered from future revenue		**225,590**		229,876
Regulatory asset-asset retirement obligation		**710,326**		694,036
Regulatory asset - OPEB		**153,235**		0
Regulatory assets - nuclear		**4,220,920**		4,248,478
Other noncurrent and regulatory assets		**189,465**		195,618
Total noncurrent assets		**10,699,543**		10,342,298
Total assets	**$**	**12,425,881**	$	12,960,692
DEFERRED OUTFLOWS OF RESOURCES				
Deferred outflows – pension	**$**	**41,859**	$	41,181
Deferred outflow - OPEB		**23,175**		0
Accumulated decrease in fair value of hedging derivatives		**39,440**		39,916
Unamortized loss on refunded and defeased debt		**134,937**		158,625
Total deferred outflows of resources	**$**	**239,411**	$	239,722
Total assets & deferred outflows of resources	**$**	**12,665,292**	$	13,200,414

The accompanying notes are an integral part of these financial statements.

Statements of Net Position - Business - Type Activities (continued)

South Carolina Public Service Authority
As of December 31, 2018 and 2017

		2018		2017
		(Thousands)		
LIABILITIES				
Current liabilities				
Current portion of long - term debt	$	**63,450**	$	48,546
Accrued interest on long - term debt		**46,383**		50,383
Revolving credit agreement		**86,234**		219,000
Commercial paper		**173,898**		144,484
Accounts payable		**230,970**		304,377
Other current liabilities		**99,952**		97,075
Total current liabilities		**700,887**		863,865
Noncurrent liabilities				
Construction liabilities		**21,504**		17,130
Net OPEB liability		**172,774**		0
Net pension liability		**338,128**		338,783
Asset retirement obligation liability		**716,666**		729,969
Total long-term debt (net of current portion)		**6,968,680**		7,465,968
Unamortized debt discounts and premiums		**386,877**		431,174
Long-term debt-net		**7,355,557**		7,897,142
Other credits and noncurrent liabilities		**95,974**		97,085
Total noncurrent liabilities		**8,700,603**		9,080,109
Total liabilities	$	**9,401,490**	$	9,943,974
DEFERRED INFLOWS OF RESOURCES				
Deferred inflows - pension	$	**16,740**	$	4,817
Deferred inflow - OPEB		**249**		0
Accumulated increase in fair value of hedging derivatives		**1,414**		5,374
Nuclear decommissioning costs		**215,551**		226,767
Regulatory inflows – Toshiba settlement		**732,325**		898,215
Total deferred inflows of resources	$	**966,279**	$	1,135,173
NET POSITION				
Net investment in capital assets	$	**1,955,185**	$	1,523,505
Restricted for debt service		**7,322**		32,430
Restricted for capital projects		**280**		1,284
Unrestricted		**334,736**		564,048
Total net position	$	**2,297,523**	$	2,121,267
Total liabilities, deferred inflows of resources & net position	$	**12,665,292**	$	13,200,414

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Statements of Revenues, Expenses and Changes in Net Position - Business - Type Activities
South Carolina Public Service Authority
Years Ended December 31, 2018 and 2017

	2018	2017
	(Thousands)	
Operating revenues		
Sale of electricity	$ 1,780,763	$ 1,732,292
Sale of water	9,507	8,575
Other operating revenue	16,350	16,116
Total operating revenues	1,806,620	1,756,983
Operating expenses		
Electric operating expenses		
Production	147,353	131,951
Fuel	603,361	562,539
Purchased and interchanged power	190,095	198,157
Transmission	25,623	23,663
Distribution	13,426	11,771
Customer accounts	15,015	16,094
Sales	5,296	12,018
Administrative and general	90,326	100,779
Electric maintenance expenses	113,550	110,368
Water operating expenses	3,320	3,061
Water maintenance expenses	1,116	1,090
Total operating and maintenance expenses	1,208,481	1,171,491
Depreciation	186,950	181,094
Sums in lieu of taxes	4,630	4,586
Total operating expenses	1,400,061	1,357,171
Operating income	406,559	399,812
Nonoperating revenues (expenses)		
Interest and investment revenue	11,103	12,403
Net increase (decrease) in the fair value of investments	5,213	(438)
Interest expense on long-term debt	(356,259)	(267,847)
Interest expense on commercial paper and other	(5,581)	(5,013)
Amortization income (expense)	(3,965)	11,951
Costs to be recovered from future revenue	(4,286)	(4,339)
U.S. Treasury subsidy on Build America Bonds	7,612	7,583
Other - net	133,257	(45,430)
Total nonoperating revenues (expenses)	(212,906)	(291,130)
Income before transfers	193,653	108,682
Capital contributions & transfers		
Distribution to the State	(17,397)	(17,751)
Total capital contributions & transfers	(17,397)	(17,751)
Change in net position	$ 176,256	$ 90,931
Net position - beginning	2,121,267	2,030,336
Total net position - ending	$ 2,297,523	$ 2,121,267

The accompanying notes are an integral part of these financial statements.

Statements of Cash Flows - Business - Type Activities

South Carolina Public Service Authority

Years Ended December 31, 2018 and 2017

	2018	2017
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	$ **1,809,663**	$ 1,726,942
Payments to non - fuel suppliers	**(301,920)**	(308,098)
Payments for fuel	**(600,371)**	(557,944)
Purchased power	**(190,095)**	(198,157)
Payments to employees	**(196,727)**	(190,707)
Other receipts-net	**292,866**	219,440
Net cash provided by operating activities	**813,416**	691,476
Cash flows from non-capital related financing activities		
Distribution to the State	**(17,397)**	(17,751)
Proceeds from long - term revolving credit agreement draw	**0**	190,000
Repayment of revolving credit agreement draw	**(120,000)**	(70,000)
Proceeds from issuance of commercial paper notes	**15,350**	30,450
Repayment of commercial paper notes	**(19,055)**	(268,888)
Refunding/defeasance of long-term debt	**(104,648)**	(120)
Repayment of long - term debt	**(17,292)**	(746)
Interest paid on long - term debt	**(213,840)**	(11,051)
Interest paid on commercial paper and other	**(4,720)**	(4,904)
Bond issuance and other related costs	**(55,131)**	(185)
Net cash used in non-capital related financing activities	**(536,733)**	(153,195)
Cash flows from capital-related financing activities		
Proceeds from revolving credit agreement draw	**54,000**	126,500
Repayment of revolving credit agreement draw	**(143,000)**	(26,000)
Proceeds from issuance of commercial paper notes	**93,168**	23,284
Repayment of commercial paper notes	**(60,049)**	(40,261)
Refunding/defeasance of long-term debt	**(253,017)**	(157,488)
Repayment of long-term debt	**(33,909)**	(127,308)
Interest paid on long-term debt	**(143,861)**	(364,062)
Interest paid on commercial paper and other	**(2,305)**	(2,415)
Construction and betterments of utility plant	**(520,810)**	(824,255)
Bond issuance and other related costs	**29,706**	(8,715)
Toshiba settlement proceeds	**0**	898,215
Other-net	**1,609**	(33,661)
Net cash used in capital related financing activities	**(978,468)**	(536,166)
Cash flows from investing activities		
Net decrease in investments	**421,355**	609,051
Interest on investments	**11,755**	13,309
Net cash provided by investing activities	**433,110**	622,360
Net increase (decrease) in cash and cash equivalents	**(268,675)**	624,475
Cash and cash equivalents - beginning	**803,123**	178,648
Cash and cash equivalents - ending	$ **534,448**	$ 803,123

The accompanying notes are an integral part of these financial statements.

Statements of Cash Flows - Business - Type Activities (continued)

South Carolina Public Service Authority
Years Ended December 31, 2018 and 2017

		2018		2017
		(Thousands)		
Reconciliation of operating income to net cash provided by operating activities				
Operating income	$	**406,559**	$	399,812
Adjustments to reconcile operating income to net cash provided by operating activities				
Depreciation		**186,950**		181,094
Amortization of nuclear fuel		**23,222**		24,792
Net power gains involving associated companies		**(50,446)**		(50,542)
Distributions from associated companies		**45,522**		46,122
Advances to associated companies		**(20)**		(27)
Other income and expenses		**150,065**		(29,488)
Changes in assets and liabilities				
Accounts receivable - net		**2,939**		(30,043)
Inventories		**177,832**		110,872
Prepaid expenses		**48,866**		25,208
Other deferred debits		**(169,483)**		(14,092)
Accounts payable		**21,096**		21,011
Other current liabilities		**(271,918)**		394
Other noncurrent liabilities		**242,232**		6,363
Net cash provided by operating activities	**$**	**813,416**	**$**	691,476
Composition of cash and cash equivalents				
Current				
Unrestricted cash and cash equivalents	$	**475,601**	$	731,758
Restricted cash and cash equivalents		**53,600**		71,338
Noncurrent				
Restricted cash and cash equivalents		**5,247**		27
Cash and cash equivalents at the end of the year	$	**534,448**	$	803,123
Noncash capital activities	$	**45,032**	$	139,536

Statements of Fiduciary Net Position - OPEB Trust Fund

South Carolina Public Service Authority
As of December 31, 2018 and 2017

		2018		2017
		(Thousands)		
ASSETS				
Cash and cash equivalents	$	**2,244**	$	2,326
Investments		**74,849**		54,583
Total current assets		**77,093**		56,909
Total assets	$	**77,093**	$	56,909
LIABILITIES				
Total liabilities	$	**0**	$	0
NET POSITION				
Restricted for other postemployment benefits (OPEB)	$	**77,093**	$	56,909
Total net position	$	**77,093**	$	56,909
Total liabilities & net position	$	**77,093**	$	56,909

The accompanying notes are an integral part of these financial statements.

Statements of Changes in Fiduciary Net Position - OPEB Trust Fund

South Carolina Public Service Authority

Years Ended December 31, 2018 and 2017

		2018		2017
		(Thousands)		
ADDITIONS				
Employer contributions	$	**20,012**	$	5,948
Total employer contributions		**20,012**		5,948
Investment income				
Appreciation (depreciation) in fair value of investments		**(1,421)**		762
Interest		**1,593**		1,308
Net investment income		**172**		2,070
Total additions		**20,184**		8,018
DEDUCTIONS				
Total deductions		**0**		0
Change in net position		**20,184**		8,018
Net position - beginning of period		**56,909**		48,891
Total net position - ending	$	**77,093**	$	56,909

The accompanying notes are an integral part of these financial statements.

NOTES

Note 1 – Summary of Significant Accounting Policies

A - Reporting Entity - The South Carolina Public Service Authority (the "Authority" or "Santee Cooper"), a component unit of the State of South Carolina ("the State"), was created in 1934 by the State legislature. The Santee Cooper Board of Directors ("Board") is appointed by the Governor of South Carolina with the advice and consent of the Senate. The purpose of the Authority is to provide electric power and wholesale water to the people of South Carolina. Capital projects are funded by bonds, commercial paper and internally generated funds. As authorized by State law, the Board sets rates charged to customers to pay debt service and operating expenses and to provide funds required under bond covenants. The Authority's financial statements include the accounts of the electric system and the Lake Moultrie and Lake Marion Regional Water Systems after elimination of inter-company accounts and transactions.

B - System of Accounts - The accounting records of the Authority are maintained on an accrual basis in accordance with accounting principles generally accepted in the United States ("GAAP") issued by the Governmental Accounting Standards Board ("GASB") applicable to governmental entities that use proprietary fund accounting.

The accounts are maintained substantially in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") for the electric system and the National Association of Regulatory Utility Commissioners ("NARUC") for the water systems.

The Authority also complies with policies and practices prescribed by its Board and practices common in both industries. As the Board is authorized to set rates, the Authority follows GASB 62. This standard provides for the reporting of assets and liabilities consistent with the economic effect of the rate structure.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions in the Authority's reporting. This practice affects the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

C - Current and Noncurrent - The Authority presents assets and liabilities in order of relative liquidity. The liquidity of an asset is determined by how readily it is expected to be converted to cash and whether restrictions limit the use of the resources. The liquidity of a liability is based on its maturity, or when cash is expected to be used to liquidate the liability.

D - Restricted Assets - For purposes of the Statements of Net Position and Statements of Cash Flows, assets are restricted when constraints are placed on their use by either:

(1) External creditors, grantors, contributors, or laws or regulations of other governments; or
(2) Law through constitutional provisions or enabling legislation.

Assets not meeting the requirements of restricted or invested in capital assets, net of related debt, are classified as unrestricted.

E - Cash and Cash Equivalents - For purposes of the Statements of Net Position and Statements of Cash Flows, the Authority considers highly liquid investments with original maturities of ninety days or less, and cash on deposit with financial institutions, as unrestricted and restricted cash and cash equivalents.

F - Inventory - Material and fuel inventories are carried at weighted average costs. At the time of issuance or consumption, an expense is recorded at the weighted average cost.

G - Utility Plant - Utility plant is recorded at cost, which includes materials, labor, overhead and interest capitalized during construction. Interest is capitalized only when interest payments are funded through borrowings. The Authority capitalized $0 and $67.9 million of interest in 2018 and 2017, respectively. Other interest expense is recovered currently through rates. The costs of maintenance, repairs and minor replacements are charged to appropriate operation and maintenance expense accounts. The costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

H - Depreciation - Depreciation is computed using composite rates on a straight-line basis over the estimated useful lives of the various classes of the plant. Composite rates are applied to the gross plant balance of various classes of assets which includes appropriate adjustments for cost of removal and salvage. The Authority periodically has depreciation studies performed by independent parties to assist management in establishing appropriate composite depreciation rates. For assets not grouped in a plant class, straight-line depreciation is used over the estimated useful life of the asset.

Annual depreciation provisions, expressed as a percentage of average depreciable utility plant in service, were as follows:

Years Ended December 31,	**2018**	2017
Annual average depreciation percentages	**2.5%**	2.5%

I - Retirement of Long Lived Assets - The Authority follows the guidance of FASB ASC 410 in regard to the decommissioning of V.C. Summer Nuclear Station ("Summer Nuclear Unit 1") and closing coal-fired generation ash ponds. The requirements for both were recorded within capital assets on the accompanying Statements of Net Position.

The asset retirement obligation ("ARO") is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The following table summarizes the Authority's transactions:

Years Ended December 31,		**2018**				2017	
	Nuclear	**Ash Ponds**	**Total**	Nuclear	Ash Ponds	Total
			(Millions)			
Reconciliation of ARO Liability:						
Balance as of January 1,	**$ 414.8**	**$ 315.2**	**$ 730.0**	$ 403.9	$ 336.0	$ 739.9
Accretion expense	**11.2**	**(24.6)**	**(13.4)**	10.9	(20.8)	(9.9)
Balance as of December 31,	**$ 426.0**	**$ 290.6**	**$ 716.6**	$ 414.8	$ 315.2	$ 730.0
Asset Retirement Cost (ARC):	**$ 92.0**	**$ 173.1**	**$ 265.1**	$ 92.0	$ 173.1	$ 265.1
Regulatory Asset - ARO	**$ 421.9**	**$ 288.4**	**$ 710.3**	$ 406.1	$ 287.9	$ 694.0

J - Reporting Impairment Losses - The Authority follows the guidance of GASB 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*, in determining if a capital asset has been impaired and the accounting treatment of such impairment. An impairment is a significant, unexpected decline in the service utility of a capital asset. Events or changes in circumstances that may be indicative of impairment include evidence of physical damage, enactment or approval of laws or regulations or other changes in environmental factors, technological changes or evidence of obsolescence, changes in the manner or duration of use of a capital asset, and construction stoppage. A capital asset generally should be considered impaired if both (a) the decline in service utility of the capital asset is large in magnitude and (b) the event or change in circumstance is outside the normal life cycle of the capital asset. Impaired capital assets that will no longer be used should be reclassified from plant balances and CWIP to another asset category and reported at the lower of carrying value or fair value.

On July 31, 2017, the Board made a decision to suspend construction on Summer Nuclear Units 2 and 3. As a result of the suspension and evaluation of circumstances, Summer Nuclear Units 2 and 3 were determined to be impaired and were written down to fair value. The resulting write-off of Summer Nuclear Units 2 and 3 construction costs, which include capitalized interest, for the year ended December 31, 2017 totaled $4.211 billion. (See Note 7 - Summer Nuclear Station- Summer Nuclear Units 2 and 3).

There were no new impairment losses for 2018, although there was a decrease of $8.3 million charged to the nuclear impairment regulatory asset for adjustments after year end 2017.

K - Other Regulatory Items - In accordance with GASB 62's guidance on regulated operations, regulated accounting rules may be applied to business type activities that have regulated operations if certain criteria are met. GASB 65, paragraph 29, further clarified regulatory accounting rules under GASB 62. Under regulatory accounting a regulated utility may defer recognition of expenses or revenues if certain criteria are met and the revenues and expenses will be included in future rates. Significant regulatory items are presented as follows:

Pee Dee
The Authority made the decision in 2007 to build a coal-fired generation plant in Florence County, South Carolina. In 2009 the Authority chose not to proceed with this plant. Assets related to this project are classified as other current and noncurrent regulatory assets. The Board gave approval to write off the total asset balance of $261.3 million over a seven-year period ending December 2020. Accordingly, $41.6 million and $42.2 million were written off in 2018 and 2017, respectively. The remaining balance outstanding at December 31, 2018 was $83.2 million.

Summer Nuclear Units 2 and 3
On December 11, 2017, the Board approved the use of regulatory accounting for a portion of the nuclear post-suspension interest balance of $37.1 million. As of December 31, 2018, the balance remains the same and the write-off of the regulatory asset will not begin until 2022.

Based on a Board resolution dated January 22, 2018, the use of regulatory accounting was approved for the Summer Nuclear Units 2 and 3. The Board gave approval to write-off the total asset balance of $4.203 billion aligned with the debt service collected in rates. Accordingly, $4.9 million was written off in 2018. The remaining balance outstanding at December 31, 2018 was $4.198 billion.

Regulatory Liability – Toshiba Settlement Agreement.
The Board of Directors approved a resolution dated December 11, 2017, authorizing use of regulatory accounting to defer recognition of income from the Toshiba Settlement Agreement. The Authority recorded a regulatory deferred inflow of $898.2 million. The deferred inflow will be amortized to align with the manner in which debt service is reduced as a result of using the proceeds. During 2018, $176.6 million was amortized, leaving a balance of $732.3 million in the regulatory liability.

Unfunded OPEB Liability
On October 13, 2017, the Board approved the use of regulatory accounting to offset the initial unfunded OPEB liability resulting from implementation of GASB 75. As a result, the Authority recorded a regulatory asset of $165.2 million. The regulatory asset will be amortized to expense in accordance with a Level Dollar, 30-year closed amortization period funding schedule provided by the Actuary. During 2018, $12.0 million was amortized to coincide with a deposit to the trust of the same amount. The remaining balance outstanding at December 31, 2018 was $153.2 million.

L - Investment in Associated Companies - The Authority is a member of The Energy Authority ("TEA"). Approximate ownership interests in TEA as of December 31, 2018 and 2017 were as follows:

Years Ended December 31,	**2018**	2017
Owners	Ownership (%)	
City Utilities of Springfield (Missouri)	**5.55**	5.55
Cowlitz Public Utility District (Washington)	**5.55**	5.55
Gainesville Regional Utilities (Florida)	**5.55**	5.55
American Municipal Power (Ohio)	**16.67**	16.67
JEA (Florida)	**16.67**	16.67
MEAG Power (Georgia)	**16.67**	16.67
Nebraska Public Power District (Nebraska)	**16.67**	16.67
Santee Cooper (South Carolina)	**16.67**	16.67
Total	**100.00**	100.00

TEA markets wholesale power and coordinates the operation of the generation assets of its members to maximize the efficient use of electrical energy resources, reduce operating costs and increase operating revenues of the members. It is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. TEA does not engage in the construction or ownership of generation or transmission assets. In addition, it assists members with fuel hedging activities and acts as an agent in the execution of forward transactions. The Authority accounts for its investment in TEA under the equity method of accounting.

All of TEA's revenues and costs are allocated to the members. The following table summarizes the transactions applicable to the Authority:

Years Ended December 31,		2018		2017
		(Thousands)		
TEA Investment:				
Balance as of January 1,	**$**	**6,382**	$	6,391
Reduction to power costs and increases in electric revenues		**46,190**		46,237
Less: Distributions from TEA		**45,522**		46,122
Less: Other (includes equity losses)		**105**		124
Balance as of December 31,	**$**	**6,945**	$	6,382
Due To/Due From TEA:				
Payable to	**$**	**21,526**	$	26,871
Receivable from	**$**	**1,785**	$	3,346

The Authority's exposure relating to TEA is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. These guarantees are within the scope of FASB ASC 952. Upon the Authority making any payments under its electric guarantee, it has certain contribution rights with the other members in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's equity ownership interest. After such contributions have been affected, the Authority would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the Authority has the ability to terminate its guarantee obligations by providing advance notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The Authority's support of TEA's trading activities is limited based on the formula derived from the forward value of TEA's trading positions at a point in time. The formula was approved by the Authority's Board**.** At December 31, 2018, the trade guarantees are an amount not to exceed approximately $84.6 million.

The Authority is also a member of TEA Solutions. TEA Solutions is a publicly supported non-profit corporation. Members and ownership interests in TEA Solutions as of December 31, 2018 and 2017were as follows:

Years Ended December 31,	2018	2017
Owners	Ownership (%)	
Cowlitz Public Service District (Washington)	**0.0**	8.0
American Municipal Power (Ohio)	**25.0**	23.0
JEA (Florida)	**25.0**	23.0
MEAG Power (Georgia)	**25.0**	23.0
Santee Cooper (South Carolina)	**25.0**	23.0
Total	**100.0**	100.0

TEA Solutions was formed mainly to (1) coordinate the operation of electric generation resources and the purchase and sale of electric power on behalf of the corporation's clients; (2) coordinate the purchase and sale of natural gas relating to fuel for clients' generation of electric energy or relating to clients' operation of a retail gas distribution system; and (3) provide consulting and software services to clients.

The Authority funded its initial share of TEA Solutions with a $150,000 contribution in 2013. This contribution was to cover legal, consulting and other start-up costs pertaining to TEA Solutions. The Authority's exposure relating to TEA Solutions is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. The balance in its member equity account at December 31, 2018 and 2017 was approximately $229,564 and $206,000, respectively.

M - Deferred Outflows / Deferred Inflows of Resources **-** In addition to assets, the Statements of Net Position reports a separate section for Deferred Outflows of Resources. These items represent a consumption of net position that applies to a future period and until that time will not be recognized as an expense or expenditure. The Authority has four items meeting this criterion: (1) deferred outflows – pension; (2) accumulated decrease in fair value of hedging derivatives; (3) unamortized loss on refunded and defeased debt; and (4) deferred outflows – OPEB.

In addition to liabilities, the Statements of Net Position also reports a separate section for Deferred Inflows of resources. These items represent an acquisition of net position that applies to a future period and until that time will not be recognized as revenue. The Authority has five items meeting this criterion: (1) deferred inflows – pension; (2) accumulated increase in fair value of hedging derivatives; (3) nuclear decommissioning costs; (4) Toshiba settlement; and (5) deferred inflows – OPEB.

The following table summarizes the Authority's total deferred items:

Years Ended December 31,		**2018**		2017
		(Thousands)		
Deferred outflows of resources	**$**	**239,411**	$	239,722
Deferred inflows of resources	**$**	**966,279**	$	1,135,173

N - Accounting for Derivative Instruments - In compliance with GASB 53 and 64, the annual changes in the fair value of effective hedging derivative instruments are required to be deferred (reported as deferred outflows of resources and deferred inflows of resources on the Statements of Net Position). Deferral of changes in fair value generally lasts until the transaction involving the hedged item ends.

Natural gas and heating oil, core business commodity inputs for the Authority, have historically been hedged in an effort to mitigate gas and oil cost risk by reducing cost volatility and improving cost effectiveness. Unrealized gains and losses related to such activity are deferred in a regulatory account and recognized in earnings as fuel costs are incurred in the production cycle.

A summary of the Authority's derivative activity for years ended December 31, 2018 and 2017 is below:

Cash Flow Hedges and Summary of Activity

Years Ended December 31,			**2018**		2017
	Account Classification		(Millions)		
Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**(37.4)**	$	(37.4)
Heating oil	Regulatory assets/liabilities		**(0.6)**		2.9
Changes in Fair Value					
Natural gas	Regulatory assets/liabilities	**$**	**0.0**	$	(6.4)
Heating oil	Regulatory assets/liabilities		**(3.5)**		1.5
Recognized Net Gains (Losses)					
Natural gas	Operating expense-fuel	**$**	**(9.2)**	$	(19.2)
Heating oil	Operating expense-fuel		**3.3**		0.5
Realized But Not Recognized Net Gains (Losses)					
Natural gas	Regulatory assets/liabilities	**$**	**(1.7)**	$	(6.9)
Heating oil	Regulatory assets/liabilities		**(0.0)**		(0.2)
Notional					
			MBTUs		
Natural gas			**123,140**		171,056
			Gallons (000s)		
Heating oil			**8,484**		7,602
Maturities					
Natural gas			**Jan 2019-Dec 2022**		Jan 2018-Dec 2022
Heating oil			**Jan 2019-Dec 2020**		Jan 2018-Dec 2019

O - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers but not billed are accrued monthly. Accrued revenue for retail customers totaled $15.8 million in 2018 and $15.4 million in 2017.

Fuel costs are reflected in operating expenses as fuel is consumed. All customers are billed utilizing rates and contracts that include fuel cost recovery components, the majority of which include monthly automatic fuel adjustment provisions which provide for adjustments to the base rates to cover increases or decreases in the cost of fuel to the extent such costs vary from the predetermined base rates. The fuel adjustment provisions are based on either the accrued costs for the previous month or the actual weighted average costs for the previous three-month period.

Rates to Central are determined in accordance with the cost of service methodology contained in the Central Agreement. Under this agreement Central initially pays monthly based on estimated rates and actual loads. The charges are then adjusted to reflect actual costs and loads, on a monthly basis for fuel and an annual basis for all other costs, and Central is charged or credited with the difference.

P - Bond Issuance Costs and Refunding Activity - GASB 62 requires that any gains or losses resulting from extinguishment of debt be expensed at the time of extinguishment. GASB 65 requires that debt issuance costs be expensed in the period incurred. In order to align the impact of these pronouncements with the Authority's rate making process, in October 2012, the Board authorized the use of regulatory accounting to allow continuation of prior accounting treatment with regard to these costs.

Consistent with prior accounting periods, unamortized debt discounts, premiums and expenses are amortized to income over the terms of the related debt issues. Gains or losses on refunded and extinguished debt are amortized to earnings over the shorter of the remaining life of the refunded debt or the life of the new debt.

Q - Distribution to the State - Any and all net earnings of the Authority not necessary for the prudent conduct and operation of its business in the best interests of the Authority or to pay the principal of and interest on its bonds, notes, or other evidences of indebtedness or other obligations, or to fulfill the terms and provisions of any agreements made with the purchasers or holders thereof or others must be paid over semiannually to the State Treasurer for the general funds of the State. Nothing in this section shall prohibit the Authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis, from the combined electric and water systems. (Code of Laws of South Carolina, as amended Section 58-31-110).

Distributions made to the State in 2018 and 2017 totaled approximately $17.4 million and $17.8 million, respectively.

R - New Accounting Standards -

STATEMENT NO. & ISSUE DATE	TITLE/SUMMARY	SUMMARY OF ACTION BY THE AUTHORITY
Statement No. GASB 74	**Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans**	Implemented in 2017
Issue Date: June 2015	Effective for Periods Beginning After: June 15, 2016	
Description:	The objective of this Statement is to improve the usefulness of information about postemployment benefits other than pensions (other postemployment benefits or OPEB) included in the general purpose external financial reports of state and local governmental OPEB plans for making decisions and assessing accountability. This Statement replaces Statements No. 43, *Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans*, as amended, and No. 57, *OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans*. It also includes requirements for defined contribution OPEB plans that replace the requirements for those OPEB plans in Statement No. 25, *Financial Reporting for Defined Benefit Pension Plans and Note Disclosures for Defined Contribution Plans*, as amended, Statement 43, and Statement No. 50, *Pension Disclosures*.	

Statement No. GASB 75	**Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions**	Implemented in 2018
Issue Date: June 2015	Effective for Periods Beginning After: June 15, 2017	
Description:	The primary objective of this Statement is to improve accounting and financial reporting by state and local governments for postemployment benefits other than pensions (other postemployment benefits or OPEB). It also improves information provided by state and local governmental employers about financial support for OPEB that is provided by other entities. This Statement replaces the requirements of Statements No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*, as amended, and No. 57, *OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans*, for OPEB. Statement No. 74, *Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans*, establishes new accounting and financial reporting requirements for OPEB plans.	
Statement No. GASB 80	**Blending Requirements for Certain Component Units—an amendment of GASB Statement 14**	Reviewed and no action required
Issue Date: January 2016	Effective for Periods Beginning After: June 15, 2016	
Description:	The objective of this Statement is to improve financial reporting by clarifying the financial statement presentation requirements for certain component units. This Statement amends the blending requirements established in paragraph 53 of Statement No. 14, *The Financial Reporting Entity, as amended.* This Statement amends the blending requirements for the financial statement presentation of component units of all state and local governments. The additional criterion requires blending of a component unit incorporated as a not-for-profit corporation in which the primary government is the sole corporate member. The additional criterion does not apply to component units included in the financial reporting entity pursuant to the provisions of Statement No. 39, *Determining Whether Certain Organizations Are Component Units*.	
Statement No. GASB 81	**Irrevocable Split-Interest Agreements**	Reviewed and no action required
Issue Date: March 2016	Effective for Periods Beginning After: December 15, 2016	
Description:	The objective of this Statement is to improve accounting and financial reporting for irrevocable split-interest agreements by providing recognition and measurement guidance for situations in which a government is a beneficiary of the agreement. Split-interest agreements are a type of giving agreement used by donors to provide resources to two or more beneficiaries, including governments. Split-interest agreements can be created through trusts—or other legally enforceable agreements with characteristics that are equivalent to split-interest agreements—in which a donor transfers resources to an intermediary to hold and administer for the benefit of a government and at least one other beneficiary. Examples of these types of agreements include charitable lead trusts, charitable remainder trusts, and life-interests in real estate. This Statement requires that a government that receives resources pursuant to an irrevocable split-interest agreement recognize assets, liabilities, and deferred inflows of resources at the inception of the agreement. Furthermore, this Statement requires that a government recognize assets representing its beneficial interests in irrevocable split-interest agreements that are administered by a third party, if the government controls the present service capacity of the beneficial interests. This Statement requires that a government recognize revenue when the resources become applicable to the reporting period.	
Statement No. GASB 82	**Pension Issues—an amendment of GASB Statements No. 67, No. 68, and No. 73**	Implemented in 2017
Issue Date: March 2016	Effective for Periods Beginning After: June 15, 2016	
Description:	The objective of this Statement is to address certain issues that have been raised with respect to Statements No. 67, *Financial Reporting for Pension Plans*, No. 68, *Accounting and Financial Reporting for Pensions*, and No. 73, *Accounting and Financial Reporting for Pensions and Related Assets That Are Not within the Scope of GASB Statement 68, and Amendments to Certain Provisions of GASB Statements 67 and 68*. Specifically, this Statement addresses issues regarding (1) the presentation of payroll-related measures in required supplementary information, (2) the selection of assumptions and the treatment of deviations from the guidance in an Actuarial Standard of Practice for financial reporting purposes, and (3) the classification of payments made by employers to satisfy employee (plan member) contribution requirements.	

Statement No. GASB 83	**Certain Asset Retirement Obligations**	Under review
Issue Date: November 2016	Effective for Periods Beginning After: June 15, 2018	
Description:	This Statement addresses accounting and financial reporting for certain asset retirement obligations (AROs). An ARO is a legally enforceable liability associated with the retirement of a tangible capital asset. A government that has legal obligations to perform future asset retirement activities related to its tangible capital assets should recognize a liability based on the guidance in this Statement.	
Statement No. GASB 84	**Fiduciary Activities**	Under review
Issue Date: January 2017	Effective for Periods Beginning After: December 15, 2018	
Description:	The objective of this Statement is to improve guidance regarding identification of fiduciary activities for accounting and financial reporting purposes and how those activities should be reported. This Statement establishes criteria for identifying fiduciary activities of all state and local governments. The focus of the criteria generally is on (1) whether a government is controlling the assets of the fiduciary activity and (2) the beneficiaries with whom a fiduciary relationship exists. Separate criteria are included to identify fiduciary component units and postemployment benefit arrangements that are fiduciary activities. This Statement describes four fiduciary funds that should be reported, if applicable: (1) pension (and other employee benefit) trust funds, (2) investment trust funds, (3) private-purpose trust funds, and (4) custodial funds.	
Statement No. GASB 85	**Omnibus 2017**	Reviewed and no action required
Issue Date: March 2017	Effective for Periods Beginning After: June 15, 2017	
Description:	The objective of this Statement is to address practice issues that have been identified during implementation and application of certain GASB Statements. This Statement addresses a variety of topics including issues related to blending component units, goodwill, fair value measurement and application, and postemployment benefits (pensions and other postemployment benefits [OPEB]).	
Statement No. GASB 86	**Certain Debt Extinguishment Issues**	Reviewed and no action required
Issue Date: May 2017	Effective for Periods Beginning After: June 15, 2017	
Description:	The primary objective of this Statement is to improve consistency in accounting and financial reporting for in-substance defeasance of debt by providing guidance for transactions in which cash and other monetary assets acquired with only existing resources—resources other than the proceeds of refunding debt—are placed in an irrevocable trust for the sole purpose of extinguishing debt. This Statement also improves accounting and financial reporting for prepaid insurance on debt that is extinguished and notes to financial statements for debt that is defeased in substance.	
Statement No. GASB 87	**Leases**	Under review
Issue Date: June 2017	Effective for Periods Beginning After: December 15, 2019	
Description:	The objective of this Statement is to better meet the information needs of financial statement users by improving accounting and financial reporting for leases by governments. This Statement increases the usefulness of governments' financial statements by requiring recognition of certain lease assets and liabilities for leases that previously were classified as operating leases and recognized as inflows of resources or outflows of resources based on the payment provisions of the contract. It establishes a single model for lease accounting based on the foundational principle that leases are financings of the right to use an underlying asset. Under this Statement, a lessee is required to recognize a lease liability and an intangible right-to-use lease asset, and a lessor is required to recognize a lease receivable and a deferred inflow of resources, thereby enhancing the relevance and consistency of information about governments' leasing activities.	

Statement No. GASB 88 **Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements**

Issue Date: April 2018 Effective for Periods Beginning After: June 15, 2018 Under review

Description: The primary objective of this Statement is to improve the information that is disclosed in notes to government financial statements related to debt, including direct borrowings and direct placements. It also clarifies which liabilities governments should include when disclosing information related to debt. This Statement defines debt for purposes of disclosure in notes to financial statements as a liability that arises from a contractual obligation to pay cash (or other assets that may be used in lieu of cash) in one or more payments to settle an amount that is fixed at the date the contractual obligation is established. This Statement requires that additional essential information related to debt be disclosed in notes to financial statements, including unused lines of credit; assets pledged as collateral for the debt; and terms specified in debt agreements related to significant events of default with finance-related consequences, significant termination events with finance-related consequences, and significant subjective acceleration clauses. For notes to financial statements related to debt, this Statement also requires that existing and additional information be provided for direct borrowings and direct placements of debt separately from other debt.

Statement No. GASB 89 **Accounting for Interest Cost Incurred before the End of a Construction Period** Under review

Issue Date: June 2018 Effective for Periods Beginning After: December 15, 2019

Description: The objectives of this Statement are (1) to enhance the relevance and comparability of information about capital assets and the cost of borrowing for a reporting period and (2) to simplify accounting for interest cost incurred before the end of a construction period.

This Statement establishes accounting requirements for interest cost incurred before the end of a construction period. Such interest cost includes all interest that previously was accounted for in accordance with the requirements of paragraphs 5–22 of Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements,* which are superseded by this Statement. This Statement requires that interest cost incurred before the end of a construction period be recognized as an expense in the period in which the cost is incurred for financial statements prepared using the economic resources measurement focus. As a result, interest cost incurred before the end of a construction period will not be included in the historical cost of a capital asset reported in a business-type activity or enterprise fund .

This Statement also reiterates that in financial statements prepared using the current financial resources measurement focus, interest cost incurred before the end of a construction period should be recognized as an expenditure on a basis consistent with governmental fund accounting principles.

Statement No. GASB 90 **Majority Equity Interests – an amendment of GASB Statements No. 14 and No. 61** Under review

Issue Date: August 2018 Effective for Periods Beginning After: December 15, 2018

Description: The primary objectives of this Statement are to improve the consistency and comparability of reporting a government's majority equity interest in a legally separate organization and to improve the relevance of financial statement information for certain component units. It defines a majority equity interest and specifies that a majority equity interest in a legally separate organization should be reported as an investment if a government's holding of the equity interest meets the definition of an investment. A majority equity interest that meets the definition of an investment should be measured using the equity method, unless it is held by a special-purpose government engaged only in fiduciary activities, a fiduciary fund, or an endowment (including permanent and term endowments) or permanent fund. Those governments and funds should measure the majority equity interest at fair value.

For all other holdings of a majority equity interest in a legally separate organization, a government should report the legally separate organization as a component unit, and the government or fund that holds the equity interest should report an asset related to the majority equity interest using the equity method. This Statement establishes that ownership of a majority equity interest in a legally separate organization results in the government being financially accountable for the legally separate organization and, therefore, the government should report that organization as a component unit.

This Statement also requires that a component unit in which a government has a 100 percent equity interest account for its assets, deferred outflows of resources, liabilities, and deferred inflows of resources at acquisition value at the date the government acquired a 100 percent equity interest in the component unit. Transactions presented in flows statements of the component unit in that circumstance should include only transactions that occurred subsequent to the acquisition.

Note 2 – Costs to be Recovered From Future Revenue (CTBR)

The Authority's rates are established based upon debt service and operating fund requirements. Depreciation is not considered in the cost of service calculation used to design rates. In accordance with GASB 62, the differences between debt principal maturities (adjusted for the effects of premiums, discounts, expenses and amortization of deferred gains and losses) and depreciation on debt financed assets are recognized as CTBR. The recovery of outstanding amounts recorded as CTBR will coincide with the repayment of the applicable outstanding debt. The Authority's summary of CTBR activity is recapped below:

Years Ended December 31,		2018		2017
		(Millions)		
CTBR regulatory asset:				
Balance	**$**	**225.6**	$	229.8
CTBR expense/(reduction to expense):				
Net expense	**$**	**4.3**	$	4.3

Note 3 – Capital Assets

Capital asset activity for the years ended December 31, 2018 and 2017 was as follows:

		Beginning Balances		Increases		Decreases		Ending Balances
				Year 2018 (Thousands)				
Utility plant	**$**	**7,545,203**	**$**	**153,718**	**$**	**(20,857)**	**$**	**7,678,064**
Long lived assets-asset retirement cost		**265,116**		**0**		**0**		**265,116**
Accumulated depreciation		**(3,773,415)**		**(216,320)**		**56,584**		**(3,933,151)**
Total utility plant-net		**4,036,904**		**(62,602)**		**35,727**		**4,010,029**
Construction work in progress		**763,490**		**415,666**		**(161,986)**		**1,017,170**
Other physical property-net		**31,628**		**0**		**(1,943)**		**29,685**
Totals	**$**	**4,832,022**	**$**	**353,064**	**$**	**(128,202)**	**$**	**5,056,884**

		Beginning Balances		Increases		Decreases		Ending Balances
				Year 2017 (Thousands)				
Utility plant	$	7,271,505	$	310,248	$	(36,550)	$	7,545,203
Long lived assets-asset retirement cost		265,116		0		0		265,116
Accumulated depreciation		(3,620,430)		(212,721)		59,736		(3,773,415)
Total utility plant-net		3,916,191		97,527		23,186		4,036,904
Construction work in progress		4,292,907		949,829		(4,479,246)[1]		763,490
Other physical property-net		5,689		26,164		(225)		31,628
Totals	$	8,214,787	$	1,073,520	$	(4,456,285)	$	4,832,022

[1] Includes a reclassification of $4.211 billion for impaired nuclear assets from construction work in progress to a regulatory asset as a result of the suspension of construction of Summer Nuclear Units 2 and 3.

Note 4 – Cash and Investments Held by Trustee and Fund Details

All cash and investments of the Authority are held and maintained by custodians and trustees. The use of unexpended proceeds from sale of bonds, debt service funds and other sources is designated in accordance with applicable provisions of various bond resolutions, the Enabling Act included in the South Carolina Code of Laws (the "Enabling Act") or by management directive. Restricted funds have constraints placed on their use (see Note 1 - D – "Restricted Assets"). The use of unrestricted funds may be either designated for a specific use by management directive or undesignated, but are available to provide liquidity for operations as needed.

Following are the details of the Authority's funds which are classified in the accompanying financial statements as unrestricted and restricted cash, cash equivalents and investments:

Years Ended December 31,	**2018**			2017		
Funds	**Cash & Cash Equivalents**	**Investments**	**Total**	Cash & Cash Equivalents	Investments	Total
			(Thousands)			
Current Unrestricted:						
Capital Improvement	**$ 80,514**	**$ 143,163**	**$ 223,677**	$ 12,848	$ 62,343	$ 75,1911
Debt Reduction	**35,067**	**77,158**	**112,225**	23,043	87,166	110,209
Funds from Taxable Borrowings	**-**	**-**	**-**	2,488	35,907	38,395
General Improvement	**22**	**-**	**22**	960	1,944	2,904
Internal Nuclear Decommissioning Fund	**2,881**	**75,479**	**78,360**	1,764	88,362	90,126
Nuclear Fuel	**11,273**	**5,998**	**17,271**	18,915	11,999	30,914
Revenue and Operating	**133,358**	**58,687**	**192,045**	37,506	79,826	117,332
Toshiba Guarantee Settlement Fund	**170,622**	**49,657**	**220,279**	609,265	288,409	897,674
Special Reserve	**41,864**	**64,127**	**105,991**	24,969	84,821	109,790
Total	**$ 475,601**	**$ 474,269**	**$ 949,870**	$ 731,758	$ 740,777	$ 1,472,535
Current Restricted:						
Funds from Tax-exempt Borrowings	**$ -**	**$ -**	**$ -**	$ 16,496	$ 113,740	$ 130,236
Debt Service Funds and Other	**53,600**	**18,666**	**72,266**	54,842	49,620	104,462
Total	**$ 53,600**	**$ 18,666**	**$ 72,266**	$ 71,338	$ 163,360	$ 234,698
Noncurrent Restricted:						
External Nuclear Decommissioning Trust	**$ 5,247**	**$ 130,714**	**$ 135,961**	$ 27	$ 135,654	$ 135,681
Total	**$ 5,247**	**$ 130,714**	**$ 135,961**	$ 27	$ 135,654	$ 135,681
TOTAL FUNDS	**$ 534,448**	**$ 623,649**	**$ 1,158,097**	$ 803,123	$ 1,039,791	$ 1,842,914
Cash and investments as of December 31, consisted of the following:						
Cash/Deposits			**$ 60,586**			$ (435)
Investments			**1,097,511**			1,843,349
Total cash and investments			**$ 1,158,097**			$ 1,842,914

Current Unrestricted Funds - These funds are used for operating activities for the Authority's respective systems. Although funds are segregated per management directive based on their intended use, since no restrictions apply, the funds are available to provide additional liquidity for operations. Included in this category is the internal Nuclear Decommissioning Fund intended by management to be used to offset future nuclear decommissioning costs and represents amounts in excess of the mandated Nuclear Regulatory Commission ("NRC") decommissioning requirement which is funded separately in an external Nuclear Decommissioning Trust. Also included are funds from taxable borrowings intended to be used for both capital construction costs and for working capital purposes, as expected at the time proceeds are borrowed, as well as funds received from the Toshiba Settlement Agreement (See Footnote 7 – Summer Nuclear Station – Summer Nuclear Units 2 and 3), intended to be used to lower debt cost.

Current Restricted Funds - These funds are restricted in their allowed use. Debt service funds are restricted for payment of principal and interest debt service on outstanding debt. Funds from tax-exempt borrowings are intended to be used for capital construction costs as expected at the time proceeds are borrowed and are restricted pursuant to sections of both the U.S. Treasury Regulations and the Internal Revenue Code that govern the use of tax-exempt debt. Other funds are restricted for other special purposes.

Noncurrent Restricted Funds - These funds are restricted as to their specific use. The external Nuclear Decommissioning Trust is restricted for future nuclear decommissioning costs and represents the mandated NRC funding requirements.

The Authority's investments are authorized by the Enabling Act, the Authority's investment policy and the Revenue Obligation Resolution. Authorized investment types include Federal Agency Securities, State of South Carolina General Obligation Bonds and U.S. Treasury Obligations, all of which are limited to a 10 year maximum maturity in all portfolios, except the decommissioning funds. Certificate of Deposits and Repurchase Agreements are also authorized with a maximum maturity of one year.

Investments are recorded at fair value in accordance with GASB Statement No. 72, Fair Value Measurement and Application. Accordingly, the gains and losses in fair value are reflected as a component of non-operating income in the Statements of Revenues, Expenses and Changes in Net Position.

The Authority's investment activity in all fund categories is summarized as follows:

Years Ended December 31,		**2018**		2017
Total Portfolio		(Billions)		
Total investments	**$**	**1.1**	$	1.8
Purchases		**28.9**		28.7
Sales		**29.6**		28.7
Nuclear Decommissioning Portfolios[1]		(Millions)		
Total investments	**$**	**209.1**	$	225.8
Purchases		**997.1**		662.8
Sales		**1,009.6**		658.7
Unrealized holding gain/(loss)		**5.7**		4.2
Repurchase Agreements [2]		(Millions)		
Balance at December 31	**$**	**100.0**	$	100.0

[1] During 2018, due to an estimated overfunding in the Internal Nuclear Decommissioning Fund, $12.0 million was released from the fund, crediting decommissioning expense.

[2] Securities underlying repurchase agreements must have a market value of at least 102 percent of the cost of the repurchase agreement and are delivered by broker/dealers to the Authority's custodial agents.

Common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk and foreign currency risk are as follows:

Risk Type	Exposure
Credit Risk - Risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. Measured by the assignment of rating by a nationally recognized statistical rating organization.	As of December 31, 2018 and 2017, all of the agency securities held by the Authority were rated AAA by Fitch Ratings, Aaa by Moody's Investors Service, Inc. and AA+ by Standard & Poor's Rating Services.
Custodial Credit Risk-Investments - Risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party.	As of December 31, 2018 and 2017, all of the Authority's investment securities are held by the Trustee or Agent of the Authority and therefore, there is no custodial risk for investment securities.
Custodial Credit Risk-Deposits - Risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party.	At December 31, 2018 and 2017, the Authority had no exposure to custodial credit risk for deposits that were uninsured and/or collateral that was held by the bank's agent not in the Authority's name.
Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer.	Investments in any one issuer (other than U. S. Treasury securities) that represent five percent or more of total Authority investments at December 31, 2018 and 2017 were as follows:

Security Type / Issuer	Fair Value 2018	Fair Value 2017
Federal Agency Fixed Income Securities	(Thousands)	
Federal Home Loan Bank	**$ 381,754**	$ 218,217
Federal National Mortgage Association	**Less than 5%**	124,782
Federal Farm Credit Bank	**249,726**	218,664
Federal Home Loan Mortgage Corp	**Less than 5%**	Less than 5%

Interest Rate Risk - Risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates.

The Authority manages its exposure to interest rate risk by investing in securities that mature as necessary to provide the cash flow and liquidity needed for operations. The following table shows the distribution of the Authority's investments by maturity as of December 31, 2018 and 2017:

		Investment Maturities as of December 31, 2018			
Security Type	**Fair Value**	**Less than 1 Year**	**1 - 5**	**6 - 10**	**More than 10 Years**
		(Thousands)			
Collateralized Deposits	**$ 202,201**	**$ 202,201**	**$ 0**	**$ 0**	**$ 0**
Repurchase Agreements	**100,000**	**100,000**	**0**	**0**	**0**
Federal Agency Discount Notes	**389,253**	**389,253**	**0**	**0**	**0**
Federal Agency Securities	**325,254**	**139,734**	**36,982**	**27,110**	**121,428**
US Treasury Bills, Notes and Strips	**80,803**	**61,501**	**0**	**0**	**19,302**
	$ 1,097,511	**$ 892,689**	**$ 36,982**	**$ 27,110**	**$ 140,730**

		Investment Maturities as of December 31, 2017			
Security Type	Fair Value	Less than 1 Year	1 - 5	6 - 10	More than 10 Years
		(Thousands)			
Certificates of Deposits	$ 522,530	$ 522,530	$ 0	$ 0	$ 0
Repurchase Agreements	100,000	100,000	0	0	0
Federal Agency Discount Notes	262,305	262,305	0	0	0
Federal Agency Securities	635,026	410,509	107,868	11,029	105,620
US Treasury Bills, Notes and Strips	323,488	303,054	876	0	19,558
	$ 1,843,349	$ 1,598,398	$ 108,744	$ 11,029	$ 125,178

The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the Nuclear Decommissioning Trust and Nuclear Decommissioning Fund. Together these accounts hold $31.8 million par in U.S. Treasury Strips ranging in maturity from May 15, 2019 to May 15, 2039. The accounts also hold $25.5 million par in government agency zero coupon securities in the two portfolios ranging in maturity from March 7, 2019 to April 15, 2030. Zero coupon bonds or U.S. Treasury Strips are subject to wider swings in their market value than coupon bonds. These portfolios are structured to hold these securities to maturity or early redemption. The Authority has a buy and hold strategy for these. Based on the Authority's current decommissioning assumptions, it is anticipated that no funds will be needed any earlier than 2042. The Authority has no other investments that are highly sensitive to interest rate fluctuations.

Foreign Currency Risk - Risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value.	The Authority is not authorized to invest in foreign currency and therefore has no exposure.
Fair Value of Investments	The Authority measures and records its investments using fair value measurement guidelines established by GAAP. These guidelines recognize a three-tiered fair value hierarchy, as follows: Level 1: Quoted prices for identical investments in active markets; Level 2: Observable inputs other than quoted market prices; and, Level 3: Unobservable inputs. The Authority had the following recurring fair value measurements as of December 31, 2018 and 2017:

		Level		
2018	**Total**	**1**	**2**	**3**
		(Thousands)		
Collateralized Deposits	**$ 202,201**	**$ 0**	**$ 202,201**	**$ 0**
Repurchase Agreements	**100,000**	**0**	**100,000**	**0**
Federal Agency Discount Notes	**389,253**	**0**	**389,253**	**0**
Federal Agency Securities	**325,254**	**0**	**325,254**	**0**
US Treasury Bills, Notes and Strips	**80,803**	**0**	**80,803**	**0**
	$ 1,097,511	**$ 0**	**$ 1,097,511**	**$ 0**

		Level		
2017	Total	1	2	3
		(Thousands)		
Certificates of Deposits	$ 522,530	$ 0	$ 522,530	$ 0
Repurchase Agreements	100,000	0	100,000	0
Federal Agency Discount Notes	262,305	0	262,305	0
Federal Agency Securities	635,026	0	635,026	0
US Treasury Bills, Notes and Strips	323,488	0	323,488	0
	$ 1,843,349	$ 0	$ 1,843,349	$ 0

Debt securities classified in Level 1 are valued using prices quoted in active markets for those securities. Certificates of Deposits and Repurchase Agreements classified in Level 2 are valued using pricing based on the securities' relationship to benchmark quoted prices.

Note 5 – Long -Term Debt

Debt Outstanding

The Authority's long-term debt at December 31, 2018 and 2017 consisted of the following:

	2018	2017	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
Revenue Obligations: (mature through 2056)				
2004 Series M (4)	**$ 11,386**	$ 11,510	4.90-5.00	100/Accreted Value
2005 Series M (4)	**4,152**	4,291	4.35	100/Accreted Value
2006 Series M (4)	**3,428**	8,134	4.20	100/Accreted Value
2007 Refunding Series B	**0**	12,410	N/A	N/A
2008 Series M (4)	**15,088**	21,084	4.50-4.80	100/Accreted Value
2009 Tax-exempt Refunding Series A	**9,520**	59,210	4.00-4.80	100
2009 Taxable Series C	**65,975**	71,440	5.14-6.224	P&I Plus Make-Whole Premium
2009 Tax-exempt Series E	**2,285**	2,285	4.75	100
2009 Taxable Series F	**100,000**	100,000	5.74	P&I Plus Make-Whole Premium
2010 Series M1 (4)	**20,354**	21,252	3.50-4.30	100/Accreted Value
2010 Refunding Series B	**64,150**	101,455	4.00-5.00	100
2010 Series M2 (4)	**11,608**	12,595	2.875-3.875	100/Accreted Value
2010 Series C (Build America Bonds) (3)	**360,000**	360,000	6.454	P&I Plus Make-Whole Premium
2011 Series M1 (4)	**22,035**	23,341	3.50-4.80	100/Accreted Value
2011 Refunding Series B	**51,680**	144,620	4.00-5.00	Non-callable
2011 Refunding Series C	**135,855**	135,855	4.375-5.00	100
2011 Series M2 (4)	**18,475**	19,515	2.70-4.20	100/Accreted Value
2012 Refunding Series A	**66,505**	74,520	3.00-5.00	100
2012 Refunding Series B	**12,200**	12,200	5.00	Non-callable
2012 Refunding Series C	**27,045**	34,555	5.00	Non-callable
2012 Tax-exempt Series D	**292,460**	298,785	3.50-5.00	100
2012 Taxable Series E	**262,830**	262,830	3.572-4.551	P&I Plus Make-Whole Premium
2012 Series M1 (4)	**16,619**	18,158	2.55-4.00	100/Accreted Value
2012 Series M2 (4)	**14,437**	15,624	2.25-3.70	100/Accreted Value
2013 Series M1 (4)	**18,716**	22,207	1.30-3.90	100/Accreted Value
2013 Tax-exempt Series A	**152,655**	252,655	5.00-5.75	100
2013 Tax-exempt Refunding Series B	**388,730**	388,730	5.00-5.125	100
2013 Taxable Series C	**250,000**	250,000	5.784	P&I Plus Make-Whole Premium
2013 Tax-exempt Series E	**506,765**	506,765	5.00-5.50	100
2014 Series M1 (4)	**31,161**	34,040	3.00-4.30	100/Accreted Value
2014 Tax-exempt Series A	**525,000**	525,000	5.00-5.50	100
2014 Tax-exempt Refunding Series B	**42,275**	42,275	5.00	100
2014 Tax-exempt Refunding Series C	**696,605**	704,525	3.00-5.50	100
2014 Taxable Refunding Series D	**31,795**	31,795	2.906-3.606	P&I Plus Make-Whole Premium
2015 Tax-exempt Refunding Series A	**586,340**	591,825	3.00-5.00	100
2015 Tax-exempt Refunding Series B	**64,870**	64,870	5.00	Non-callable
2015 Series M1 (4)	**32,974**	35,437	1.75-3.85	100/Accreted Value
2015 Tax-exempt Refunding Series C	**155,080**	198,770	5.00	Non-callable
2015 Taxable Series D	**169,657**	169,657	4.77	P&I Plus Make-Whole Premium
2015 Tax-exempt Series E	**300,000**	300,000	5.25	100

	2018	2017	Interest Rate(s) (1)	Call Price (2)
	(Thousands)		(%)	(%)
2016 Tax-exempt Refunding Series A	**543,745**	543,745	3.125-5.00	100
2016 Series M1 (4)	**38,654**	41,294	1.65-3.75	100/Accreted Value
2016 Tax-exempt Refunding Series B	**508,705**	508,705	2.25-5.25	100
2016 Tax-exempt Refunding Series C	**52,400**	52,400	3.00-5.00	100
2016 Taxable Series D	**322,650**	322,650	2.388	P&I Plus Make-Whole Premium
Total Revenue Obligations	**7,006,864**	7,413,014		
Long-Term Revolving Credit Agreement: (matures through 2029)	**25,266**	101,500	N/A	N/A
Less: Current Portion - Long-term Debt	**63,450**	48,546		
Total Long-term Debt - (Net of current portion)	**$ 6,968,680**	$ 7,465,968		

(1) Interest Rates apply only to bonds outstanding as of December 31, 2018.

(2) Call Price may only apply to certain maturities outstanding at December 31, 2018.

(3) These bonds were issued as "Build America Bonds" under the American Recovery and Reinvestment Act of 2009 and are eligible to receive an interest subsidy payment from the United States Department of Treasury in an amount up to 35% of interest payable on the bonds.

(4) Includes Current Interest Bearing Bonds (CIBS) and Capital Appreciation Bonds (CABS).

Changes in Long-Term Debt

Long-term debt (LTD) activity for the years ended December 31, 2018 and 2017 was as follows:

	Gross LTD Beginning Balances	Increases	Decreases	Gross LTD Ending Balances	Current Portion LTD	Total LTD (Net of Current Portion)	Unamortized Debt Discounts and Premiums	LTD-Net Ending Balances
				YEAR 2018 (Thousands)				
Revenue Obligations	**$ 7,413,014**	**$ 2,715**	**$ (408,865)**	**$ 7,006,864**	**$ 63,450**	**$ 6,943,414**	**$ 386,877**	**$ 7,330,291**
Long-Term Revolving Credit Agreement	**101,500**	**0**	**(76,234)**	**25,266**	**0**	**25,266**	**0**	**25,266**
Totals	**$ 7,514,514**	**$ 2,715**	**$ (485,099)**	**$ 7,032,130**	**$ 63,450**	**$ 6,968,680**	**$ 386,877**	**$ 7,355,557**
				YEAR 2017 (Thousands)				
Revenue Obligations	$ 7,695,552	$ 3,124	$ (285,662)	$ 7,413,014	$ 48,546	$ 7,364,468	$ 431,174	$ 7,795,642
Long-Term Revolving Credit Agreement	100,000	101,500	(100,000)	101,500	0	101,500	0	101,500
Totals	$ 7,795,552	$ 104,624	$ (385,662)	$ 7,514,514	$ 48,546	$ 7,465,968	$ 431,174	$ 7,897,142

Summary of Long-Term Principal and Interest

Maturities and projected interest payments of long-term debt are as follows:

Year Ending December 31,	Revenue Obligations	Long-Term Revolving Credit Agreement	Total Principal	TOTAL INTEREST [1]	TOTAL
			(Thousands)		
2019	$ 45,905	$ 0	$ 45,905	$ 341,922	$ 387,827
2020	112,650	16,266	128,916	337,870	466,786
2021	178,106	0	178,106	331,957	510,063
2022	129,802	1,335	131,137	323,422	454,559
2023	463,870	1,335	465,205	318,657	783,862
2024-2028	687,305	6,330	693,635	1,463,829	2,157,464
2029-2033	777,288	0	777,288	1,306,270	2,083,558
2034-2038	937,746	0	937,746	1,095,382	2,033,128
2039-2043	856,215	0	856,215	880,085	1,736,300
2044-2048	1,264,237	0	1,264,237	611,354	1,875,591
2049-2053	1,199,040	0	1,199,040	276,580	1,475,620
2054-2056	354,700	0	354,700	28,134	382,834
Total	$ 7,006,864	$ 25,266	$ 7,032,130	$ 7,315,462	$ 14,347,592

[1] Does not reflect impact of subsidy interest payments on 2010 Taxable C (Build America Bonds). Years 2019-2028 include projected interest for Long-Term Revolving Credit Agreement.

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Summary of Refunded and Defeased Debt and Unamortized Losses

Refunded and defeased debt, original loss on refunding and the unamortized loss at December 31, 2018 are as follows:

Refunding Description		Refunded/Defeased Debt		Outstanding	Original Loss	Unamortized Loss
		(Thousands)			(Thousands)	
Cash Defeasance	$	20,000	1982 Series A	$ 0	$ 2,763	$ 258
2009 Refunding Series A	$	99,515	1997 Refunding Series A			
		20,125	1998 Refunding Series B	0	8,707	243
2010 Refunding Series B	$	30,430	2001 Series A			
		118,600	2002 Series B			
		84,780	2002 Refunding Series D	0	22,954	3,353
2011 Refunding Series B	$	8,990	2002 Refunding Series D			
		291,825	2004 Series A	0	23,287	1,073
2011 Refunding Series C	$	134,715	2002 Series B			
		5,160	2007 Series A	0	4,362	3,036
2012 Refunding Series A	$	73,535	2003 Refunding Series A			
		34,160	2004 Series A	0	12,206	4,038
Feb 2012 Defeasance	$	5,615	2003 Refunding Series A	0	749	489
2013 Refunding Series B	$	209,426	2003 Refunding Series A			
		7,070	2004 Series A			
		5,000	2006 Series A			
		6,565	2007 Series A			
		82,605	2008 Series B			
		1,125	2009 Series B			
		30,158	2011 Series A (LIBOR Index)			
		2,040	2012 Series D	0	14,446	11,585
2013 Refunding Series C	$	35,584	2003 Refunding Series A			
		97,695	2008 Series B	0	4,601	3,452
2014 Refunding Series C &	$	10,870	2003 Refunding Series A			
Taxable Refunding Series D		11,395	2005 Refunding Series A			
		419,105	2006 Series A			
		10,385	2006 Refunding Series C			
		175,775	2007 Series A			
		4,230	2007 Refunding Series B			
		15,000	2008 Series A			
		15,200	2009 Series B			
		12,920	2010 Refunding Series B			
		3,100	2011 Refunding Series B			
		5,625	2012 Refunding Series A			
		2,000	2012 Refunding Series B			
		15,185	2012 Refunding Series C			
		11,335	2012 Series D			
		18,185	2013 Taxable Series D (LIBOR Index)			
		44,075	Expansion Bond Refunding CP	11,885	32,936	26,219

Summary of Refunded and Defeased Debt and Unamortized Losses (continued)

Refunding Description		Refunded/Defeased Debt		Outstanding	Original Loss	Unamortized Loss
		(Thousands)			(Thousands)	
2015 Refunding Series A	$	13,370	2006 Series A			
		32,750	2007 Series A			
		93,035	2008 Series A			
		30,765	2009 Series B	$ 123,800	$ 21,487	$ 12,636
2015 Refunding Series B	$	78,150	2005 Refunding Series C	0	4,987	2,846
2015 Refunding Series C	$	87,560	2005 Refunding Series A			
		217,065	2005 Refunding Series B	0	24,366	6,504
2015 Series E	$	100,000	Barclays Revolving Credit Agreement	0	89	82
2016 Refunding Series A	$	75,885	2007 Series A			
		278,950	2008 Series A			
		20,905	2009 Refunding Series A			
		112,210	2009 Series B			
		75,000	2014 Series A (Step Coupon Bond)	487,065	56,068	47,719
2016 Refunding Series B	$	97,715	2009 Series E	97,715	12,873	11,404
Total				$ 720,465	$ 246,881	$ 134,937

Summary of In-Substance Defeasance of Debt Using Only Existing Resources

Defeased debt, cash placed in escrow, and defeased debt outstanding at December 31, 2018 are as follows:

Description of Transaction		Defeased Debt		Cash Place in Escrow	Defeased Debt Outstanding
				(Thousands)	
09/2018 Cash Defeasance	$	48,475	2009 Refunding Series A		
		37,305	2010 Refunding Series B		
		81,510	2011 Refunding Series B		
		8,015	2012 Refunding Series A		
		7,510	2012 Refunding Series C		
		6,325	2012 Series D		
		100,000	2013 Series A		
		7,920	2014 Refunding Series C		
		5,485	2015 Series A		
		43,690	2015 Refunding Series C	$ 371,403	$ 346,235
12/2018 Cash Defeasance	$	11,430	2011 Refunding Series B	11,707	11,430
Total				$ 383,110	$ 357,665

Analysis of Prior Year Current Portion of Long-term Debt

As a part of its long-term capital structure plan, the Authority will be involved in a multi-year refinancing plan. As a result, each year certain maturities classified as current portion of long-term debt may be refinanced in the subsequent year prior to the maturity date.

Below is an analysis of the 2017 current portion of long-term debt showing the amounts paid as debt service in 2018. The remaining amount represents five percent of the original principal for all outstanding minibond issues.

Analysis of December 31, 2017 Current Portion of Long-term Debt:	(Thousands)
Principal debt service paid from 2018 Revenues	$ 29,263
Minibond CAB accretion debt service paid from 2018 Revenues	1,738
Other:	
5% current portion requirement for original minibond issue amount [1]	17,545
Total	$ 48,546

[1] Represents five percent annual cap on the requirement related to put features on all outstanding minibond issues. This is an accounting entry only and does not impact debt service.

An analysis of the $134,055 current portion of long-term debt at December 31, 2016 showed that $116,510 was debt service paid from revenues. The remaining $17,545 represented five percent of the original principal for outstanding minibond issues.

Reconciliations of Interest Charges

Years Ended December 31,	**2018**	2017
	(Thousands)	
Reconciliation of interest cost to interest expense:		
Total interest cost	**$ 360,822**	$ 376,108
Capitalized interest	**0**	(67,911)
Deferred interest expense [1]	**0**	(37,076)
Interest charged to fuel expense	**(4,563)**	(3,274)
Total interest expense on long-term debt	**$ 356,259**	$ 267,847
Reconciliation of interest cost to interest payments:		
Total interest cost	**$ 360,822**	$ 376,108
Accrued interest-current year	**(46,383)**	(50,383)
Accrued interest-prior year	**50,383**	54,418
Interest released by refundings	**(4,470)**	(1,906)
Accretion on capital appreciation minibonds	**(2,651)**	(3,124)
Total interest payments on long-term debt	**$ 357,701**	$ 375,113

[1] On December 31, 2017, deferred interest was transferred to a regulatory asset per Board approval during the December Board meeting.

Debt Service Coverage

Years Ended December 31,		**2018**		2017
		(Thousands)		
Operating revenues	**$**	**1,806,620**	$	1,756,983
Interest and investment revenue		**11,103**		12,403
Total revenues and income		**1,817,723**		1,769,386
Operating expenses		**(1,400,061)**		(1,357,171)
Depreciation		**186,950**		181,094
Total expenses		**(1,213,111)**		(1,176,077)
Funds available for debt service prior to distribution to the State		**604,612**		593,309
Distribution to the State		**(17,397)**		(17,751)
Funds available for debt service after distribution to the State	**$**	**587,215**	$	575,558
Debt Service on Accrual Basis:				
Principal on long-term debt	**$**	**30,955**	$	124,857
Interest on long-term debt		**360,264**		267,847
Long-term debt service paid from Revenues		**391,219**		392,704
Commercial paper and other principal and interest		**21,428**		17,014
Total debt service paid from Revenues	**$**	**412,647**	$	409,718
Debt Service Coverage Ratio:				
Excluding commercial paper and other:				
Prior to distribution to the State		**1.54**		1.51
After distribution to the State		**1.50**		1.46
Including commercial paper and other:				
Prior to distribution to the State		**1.46**		1.44
After distribution to the State		**1.42**		1.40

Fair Value of Debt Outstanding

The fair value of the Authority's debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the Authority for debt with the same remaining maturities. Based on the borrowing rates currently available to the Authority for debt with similar terms and average maturities, the fair value of debt was $7.4 billion and $8.4 billion at December 31, 2018 and 2017, respectively.

Bond Market Transactions

There were no bond issuances for the year ended December 31, 2018.

Debt Covenant Compliance

As of December 31, 2018 and 2017, management believes the Authority was in compliance with all debt covenants. The Authority's bond indentures provide for certain restrictions, the most significant of which are:

(1) the Authority covenants to establish rates sufficient to pay all debt service, required lease payments, capital improvement fund requirements and all costs of operation and maintenance of the Authority's Electric and Water Systems and all necessary repairs, replacements and renewals thereof; and
(2) the Authority is restricted from issuing additional parity bonds unless certain conditions are met.

All Authority debt (Electric and Water Systems) issued pursuant to the Revenue Obligation Resolution is payable solely from and secured by a lien upon and pledge of the applicable Electric and Water Revenues of the Authority. Revenue Obligations are senior to:

(1) payment of expenses for operating and maintaining the Systems;
(2) payments for debt service on commercial paper; and
(3) payments made into the Capital Improvement Fund.

Bond Outstanding Summary

As of December 31,	**2018**	2017
Outstanding Revenue Obligations	**$ 7.0 Billion**	$ 7.4 Billion
Estimated remaining interest payments	**$ 7.3 Billion**	$ 7.9 Billion
Issuance years (inclusive)	**2004 through 2016**	2004 through 2016
Maturity years (inclusive)	**2019 through 2056**	2018 through 2056

Note: Proceeds from these bonds were/will be used to fund a portion of the Authority's ongoing capital program or retire or refund certain outstanding debt of the Authority.

Note 6 – Variable Rate Debt

The Board has authorized the issuance of variable rate debt not to exceed 20 percent of the aggregate Authority debt outstanding (including commercial paper) as of the last day of the most recent fiscal year for which audited financial statements of the Authority are available. At December 31, 2018, four percent of the Authority's aggregate debt outstanding was variable rate. The lien and pledge of Revenues securing variable rate debt issued as Revenue Obligations is senior to that securing commercial paper.

Commercial paper is issued for valid corporate purposes with a term not to exceed 270 days. The information related to commercial paper was as follows:

Years Ended December 31,		**2018**		2017
Commercial paper outstanding (000's)	**$**	**173,898**	$	144,484
Effective interest rate (at December 31)		**2.48%**		1.48%
Average annual amount outstanding (000's)	**$**	**165,853**	$	269,521
Average maturity		**38 Days**		35 Days
Average annual effective interest rate		**2.01%**		1.09%

As of December 31, 2018, the Authority had secured Irrevocable Direct Pay Letters of Credit and Reimbursement Agreements with Bank of America, N.A. and Wells Fargo Bank, N.A. totaling $278.1 million. These agreements are used to support the Authority's issuance of up to $250.0 million of commercial paper. As of December 31, 2017, the Authority had secured Irrevocable Direct Pay Letters of Credit and Reimbursement Agreements with Bank of America, N.A., U.S. Bank, N.A., and Wells Fargo Bank, N.A. totaling $389.4 million. These agreements are used to support the Authority's issuance of up to $350.0 million of commercial paper. There were no borrowings under the agreements during 2018 or 2017.

As of December 31, 2018, the Authority had a Revolving Credit Agreement with Barclays Bank PLC for $200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on September 22, 2015, was amended on June 9, 2017, and expires November 26, 2020. In March 2017, the Authority secured a $50.0 million loan under the Direct Purchase Revolving Credit Agreement to pay off $50.0 million of Commercial Paper Notes. In April 2017, the Authority secured a $50.0 million loan under the Direct Purchase Revolving Credit Agreement to pay off $50.0 million of Commercial Paper Notes. The Authority paid off $70.0 million of these Direct Purchase Revolving Credit Agreement loans in 2017. In March 2018, the Authority secured a $42.0 million loan under the Direct Purchase Revolving Credit Agreement for capital expenditures. The Authority paid off $142.0 million of these Direct Purchase Revolving Credit Agreement loans in 2018. A total of $30.0 million of loans under this Agreement remain outstanding at December 31, 2018.

As of December 31, 2018, the Authority had a Revolving Credit Agreement with TD Bank, N.A. for $200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on July 27, 2017, and expires June 30, 2021. In August 2017, the Authority secured a $125.0 million loan under the Direct Purchase Revolving Credit Agreement to pay off $125.0 million of Commercial Paper Notes. In December 2017, the Authority secured an $89.0 million loan under the Direct Purchase Revolving Credit Agreement to defease certain outstanding Revenue Obligation Bonds. The Authority paid off $26.0 million of these Direct Purchase Revolving Credit Agreement loans in 2017. In March 2018, the Authority secured a $12.0 million loan under the Direct Purchase Revolving Credit Agreement for capital expenditures. The Authority paid off $121.0 million of these Direct Purchase Revolving Credit Agreement loans in 2018. A total of $79.0 million of loans under this Agreement remain outstanding at December 31, 2018.

As of December 31, 2018, the Authority had a Revolving Credit Agreement with J.P. Morgan Chase Bank, N.A. for $250.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on August 1, 2017, and expires August 7, 2020. In August 2017, the Authority secured a $2.5 million loan under the Direct Purchase Revolving Credit Agreement to pay off $2.5 million of Commercial Paper Notes. A total of $2.5 million of loans under this Agreement remain outstanding at December 31, 2018.

As of December 31, 2018, the Authority had a Revolving Credit Agreement with Wells Fargo Bank, N.A. for $200.0 million. This agreement is used to obtain funds if needed. The agreement was entered into on August 1, 2017, and expires August 9, 2019. There were no borrowings under this agreement in 2018 or 2017.

Note 7 – Summer Nuclear Station

Summer Nuclear Unit 1

The Authority and SCE&G (which became Dominion Energy as of January 01, 2019; See Footnote 15 - Subsequent Events) are parties to a joint ownership agreement providing that the Authority and SCE&G shall own Unit 1 at the Summer Nuclear Station ('Summer Nuclear Unit 1" with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. SCE&G is solely responsible for the design, construction, budgeting, management, operation, maintenance and decommissioning of Summer Nuclear Unit 1 and the Authority is obligated to pay its ownership share of all costs relating thereto. The Authority receives 33 1/3 percent of the net electricity generated. In 2004, the NRC granted a twenty-year extension to the operating license for Summer Nuclear Unit 1, extending it to August 6, 2042.

Authority's Share of Summer Nuclear - Unit 1

Years Ended December 31,	**2018**	2017
	(Millions)	
Plant balances before depreciation	**$ 579.6**	$ 556.4
Accumulated depreciation	**347.6**	349.3
Operation & maintenance expense	**87.7**	86.1

Nuclear fuel costs are being amortized based on energy expended using the unit-of-production method. This amortization is included in fuel expense and recovered through the Authority's rates.

SCE&G contracted with HOLTEC International, The Shaw Group, Inc. and Westinghouse to build a licensed Independent Spent Fuel Storage Installation ("ISFSI"), which was completed and commenced receiving fuel in 2016. Because of Department of Energy's ("DOE") failure to meet its obligation to dispose of spent fuel, SCE&G and the Authority are being reimbursed by DOE for ISFSI project costs. The Authority expects this reimbursement will equal approximately 75 percent of total project cost, which amounts to $44.1 million (Authority's 1/3 share). Through December 31, 2018, reimbursements received equal $33.1million (Authority's 1/3 share), which equals approximately 73 percent of total project expenditures.

The NRC requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2016 and the NRC's imposed minimum requirement. Based on these estimates and assuming a SAFSTOR (delayed) decommissioning, the Authority's one-third share of the estimated decommissioning costs of Summer Nuclear Unit 1 equals approximately $415.1 million in 2016 dollars. As deposits are made, the Authority debits FERC account 532 – Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates. During 2018 $12.0 million was transferred out of the internal fund because that fund's balances exceeded necessary funding and this withdraw was credited to FERC account 532 as well.

Based on current decommissioning cost estimates, these funds, which total approximately $209.1 million (adjusted to market) at December 31, 2018, along with investment earnings and credits from future DOE reimbursements for spent fuel storage, are estimated to provide enough funds for the Authority's one-third share of the total decommissioning cost for Summer Nuclear Unit 1.

Summer Nuclear Units 2 and 3

Engineering, Procurement and Construction Agreement and Project History. On May 23, 2008, SCE&G, acting for itself and as agent for the Authority (together, the "Owners"), entered into an Engineering, Procurement, and Construction Agreement (the "EPC Agreement"), with a consortium consisting of Westinghouse and Stone & Webster, Inc. (the "Consortium"). Pursuant to the EPC Agreement, the Consortium would supply, construct, test, and startup two 1,117 MW nuclear generating units utilizing Westinghouse's AP 1000 standard plant design. The EPC Agreement included substantial completion dates of April 2016 and January 2019 for Summer Nuclear Units 2 and 3 (the "Project" or "Summer Nuclear Units 2 and 3"), respectively.

On October 20, 2011, the Owners entered into a Design and Construction Agreement specifying an Authority ownership interest of 45% in each of Summer Nuclear Unit 2 and Summer Nuclear Unit 3. Among other things, the Design and Construction Agreement allowed either or both parties to withdraw from the project under certain circumstances. The Authority and SCE&G also entered into an Operating and Decommissioning Agreement on October 20, 2011 with respect to the two units. Both the Design and Construction Agreement and the Operating and Decommissioning Agreement defined the conditions under which the Authority or SCE&G could convey an undivided ownership interest in the units to a third party.

On December 30, 2011 the Nuclear Regulatory Commission ("NRC") approved the AP 1000 standard plant design (DCD Revision 19) for Summer Nuclear Units 2 and 3. On March 30, 2012, the NRC issued the Combined Construction and Operating Licenses (the "COLs") with certain conditions for Summer Nuclear Units 2 and 3.

On October 27, 2015, the Owners executed a Limited Agency Agreement that appointed SCE&G to act as the Authority's agent in connection with an amendment to the EPC Agreement. The amended EPC Agreement, which became effective on December 31, 2015, included, among other things, an irrevocable option (the "Fixed Price Option") which SCE&G executed on behalf of the Owners on July 1, 2016, to further amend the EPC Agreement to fix the total amount to be paid to the Consortium for its entire scope of work on the Project (excluding a limited amount of work within the time and materials component of the contract price) after June 30, 2015 at $6.082 billion (Authority's 45% portion being $2.737 billion), subject to adjustment for amounts paid since June 30, 2015. The amended EPC Agreement also provided for Toshiba Corporation, Westinghouse's parent company, to reaffirm its guaranty of Westinghouse's payment obligations (the "Guaranty") and revised the substantial completion dates of Units 2 and 3 to August 31, 2019 and August 31, 2020, respectively.

Toshiba Financial Difficulties/Westinghouse Bankruptcy. In late 2015, following disclosures regarding its operating and financial performance and near-term liquidity, Toshiba Corporation's ("Toshiba") credit ratings declined to below investment grade. Pursuant to the terms of the EPC Agreement, the Owners obtained payment and performance bonds from Westinghouse in the form of standby letters of credit totaling $45.0 million (the Authority's 45% share is $20.3 million).

On December 27, 2016, Toshiba announced financial difficulties related to the goodwill associated with the Westinghouse acquisition of Stone & Webster. Following several announcements and related media reports, on February 14, 2017, Toshiba, the parent company of Westinghouse and the guarantor of its financial and performance obligations with respect to the EPC Agreement, announced that it preliminarily recorded a multi-billion dollar impairment loss associated with the construction of Summer Nuclear Units 2 and 3 and the two additional AP1000 units being constructed by Westinghouse for another company in the United States (Plant Vogtle). The impaired goodwill resulted from Westinghouse's analysis that the cost to complete the four Westinghouse AP1000 new nuclear plants in the United States would far surpass the original estimates for construction. Toshiba attributed the cost overruns to, among other things, higher labor costs arising from lower than anticipated work efficiency and the inability to improve such work efficiency over time. On April 11, 2017 Toshiba released their unaudited quarterly securities report for the period covering April 1, 2016 to December 31, 2016 showing a loss of 532 billion Yen (US $4.800 billion).

On March 29, 2017, Westinghouse and 29 affiliated companies filed a Petition pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court for the Southern District of New York. This Petition allowed for a transition and evaluation period during which the Owners would assess information provided by Westinghouse and determine the most prudent path forward for the project. After the filing of the bankruptcy proceeding, the Owners entered into negotiations with Toshiba Corporation for the purpose of acknowledging and defining Toshiba's obligation under Toshiba's May 23, 2008 Guaranty and establishing a schedule for the full payment of that obligation to the Owners.

Toshiba Settlement Agreement (the "Settlement Agreement" or "Toshiba Settlement Agreement"). On July 27, 2017 the Owners and Toshiba entered into a Settlement Agreement that provided, among other things: A) Toshiba's agreement that it would pay the Guaranty obligation in the amount of $2.168 billion (Authority's 45% share was $975.6 million) , in accordance with a schedule set forth in the Settlement Agreement; B) Toshiba's agreement that payment of the Guaranty obligation and related payment schedule would not be dependent on whether one or both of the two units are completed; C) Toshiba's agreement that the Owners' were not releasing any claims or rights against Westinghouse; D) Toshiba's agreement not to subordinate the Guaranty obligations except to working capital lenders and other relationships necessary to continue and enhance its financial condition; E) Toshiba, Westinghouse, and the owners of the Vogtle and Summer Nuclear AP1000 Project's agreement to become parties to a consent order in the Bankruptcy Court that approves assignment by Toshiba to the Summer Nuclear and Vogtle owners of all rights to the non-U.S. assets in the Westinghouse family of companies owned by Toshiba, any of Toshiba's rights against Westinghouse relating to loans, and similar receivables; F) agreement by the parties to the Settlement Agreement to work towards an expeditious sale of Westinghouse; G) the Owners' agreement that the distribution proceeds received from the Westinghouse bankruptcy would be a credit against the Guaranty; and H) the Owners' agreement not to exercise remedies of the Guaranty, absent a default, until September 2022.

On September 1, 2017, the Owners filed two proofs of claim in unliquidated amounts in the Westinghouse Bankruptcy Proceeding.

On September 27, 2017, the Owners entered into an Assignment and Purchase Agreement under which they sold and assigned rights to receive payment under the Settlement Agreement and rights, duties and obligations arising under two proofs of claim filed in the Westinghouse Bankruptcy Proceeding to Citibank, N.A., in exchange for a purchase price in the amount of $1,847,075,400. The Authority's share of the purchase price was $831,183,930. Excluded from the sale was the first $150.0 million (Authority's 45% share was $67.5 million) payment under the Toshiba Settlement Agreement, which was received by the Owners.

On January 2, 2018, the Owners entered into Amendment No. 1 of the Settlement Agreement and Amendment No. 1 of the Assignment and Purchase Agreement, which amendments had the effect of capping at $60.0 million the Owners' current obligation to reimburse Citibank, N.A. for payments from the Westinghouse Estate that had the effect of reducing mechanics liens at the site (Authority's 45% share is $27.0 million).

Developments in the Westinghouse Bankruptcy Proceeding. On March 28, 2018, the United States Bankruptcy Court for the Southern District of New York issued its order confirming Westinghouse Electric Company's Modified Second Amended Joint Chapter 11 Plan of Reorganization. The plan provides for, among other things, the sale of Westinghouse to Brookfield Business Partners, L.P. for $4.6 billion, a sale that closed on August 1, 2018.

The plan also provides for payment to allowed general unsecured creditors in an amount equal to the lesser of (i) its pro rata share of certain funds; or (ii) 100% of the amount of the allowed claim. Claims by those providing materials and services at the site have been classified under the plan as general unsecured creditors. Payments from the Westinghouse Estate that have the effect of reducing mechanics liens at the site have the potential to increase amounts that must be paid by the Authority to reimburse CITIBANK.

On December 15, 2018, an initial distribution was made to general unsecured creditors equaling about 25% of the allowed amount of each claim. The total amount of the allowed general unsecured claim pool is not currently known, but the size of that pool plays a significant factor in determining the amount each allowed general unsecured creditor will be paid. It is currently anticipated that allowed general unsecured creditors will receive full or substantially full payment; however, that cannot yet be confirmed as payment of allowed general unsecured claims will not be completed until the later part of 2019.

Cost to Complete and Construction Suspension. Beginning in late March 2017, the Owners formed an independent team led by the SCE&G construction manager to undertake a rigorous Estimate-to-Complete ("ETC") validation process, including the costing/scheduling expertise of High Bridge Associates and the expertise of AECOM Energy & Construction Inc. in the area of salvage, site restoration and preservation. The process began with gathering and validating information and data received from Westinghouse and Fluor, and creating a new schedule model using Owner, Fluor and Westinghouse schedules. On a parallel track and during the same time frame, the Authority retained nFront Consulting LLC to undertake an assessment of the projected cost of power from Summer Nuclear Units 2 and 3 if completed, compared to other alternatives in meeting future energy needs of the Authority.

Based upon the ETC validation process, management of the Authority found the results of the ETC validation process adequate to determine the viability of the Project; those results estimating the schedule to complete Unit 2 would be delayed at least 40 months beyond the August 2019 contract completion date, and the estimated schedule to complete Unit 3 would be delayed at least 43 months beyond the August 2020 contract completion date. Based on both studies, the estimated cost to the Authority to complete both units, including construction period interest, increased from $8.100 billion to $11.400 billion, and the cumulative average system cost of power would be substantially higher if one or both units were completed as compared to suspending construction.

On July 31, 2017, the Board of Directors of the Authority, by Resolution authorized the President and CEO, among other things, to immediately begin taking those actions necessary to wind-down and suspend construction on the two 1,100 MW nuclear units at the Summer Nuclear site in Fairfield County, and protect and preserve both the site and related plant components and equipment. That resolution contemplated the establishment of a Project construction cessation plan and process of seeking additional support for the Project to remain in place for up to a period of one year from the date of the Resolution. There are currently no legal or regulatory requirements for the site to be maintained or restored to its original condition. As such, no removal or restoration costs have been accrued.

Upon suspending the Project, and in accordance with GASB 62, the Authority ceased capitalizing interest expense on the debt incurred to fund the Project as of July 31, 2017.

As of December 31, 2017 the Owners identified assets that could be utilized at Summer Nuclear Unit 1, consisting of various buildings and structures totaling $44.8 million (Authority's 45% share). These assets were transferred to Summer Nuclear Unit 1, and as a result in the difference of ownership percentage, the assets were recorded on Unit 1 at $32.8 million (Authority's 33.33% share) and a receivable in the amount of $12.0 million was recorded on the Authority's books. In April 2018, the Authority received payment of $11.4 million to complete the transaction for the assets transferred to Summer Nuclear Unit 1. As of December 31, 2018, the Owners agreed to a reduction in the Authority's ownership of the switchyard at the Summer Nuclear site from 32.19% to 27.08%. As a result, a receivable in the amount of $2.7 million was recorded on the Authority's books. In addition, the Authority constructed transmission assets concurrently with the Project. These assets, which include switchyard costs, total $212.8 million at December 31, 2018, and will be utilized to enhance the Authority's transmission system.

Impairment of Project Assets. With suspension of the Project construction, the Authority sought additional project partners and financial support. South Carolina's Governor indicated that he contacted a number of companies inquiring about their interest in purchasing or partnering in the Project. As of December 31, 2017 the Authority had not received or been informed of any proposal to purchase the Project or partner in the Project. As such an evaluation was conducted to determine whether the assets were impaired. In accordance with GASB 42, the assets are impaired based on A) the decline in service utility of the capital asset is large in magnitude and B) the event or change in circumstance is outside the normal life cycle of the capital asset. While the Project could be completed at some point in the future, the Authority had no near-term plans to complete the Project. Except for the assets described above that will be utilized at Summer Nuclear Unit 1 or used to enhance the Authority's transmission system, the remaining Project assets, including the nuclear fuel, were determined to be impaired.

In addition to the lack of proposals by a third party to purchase or partner in the Project, the Authority also considered several other items in order to determine the fair value of the impaired assets.

The AP1000 is a new technology. There are no completed AP1000s in the United States and only two other units under construction in the United States. There was not an active liquid market for the purchase of these partially completed units.

SCE&G obtained several estimates of the salvage value of the remaining Project assets. The highest estimate was for approximately $150.0 million (Authority's share of this would be 45%). Westinghouse cited contractual provisions that it believes indicate that the Owners may not have unencumbered title to the proceeds of the sale of the assets. Should the sale of the assets move forward, a final determination regarding ownership of the sale proceeds might be delayed.

On December 27, 2017 SCE&G, based on the decision to abandon the Project, submitted a letter request to the NRC for approval to withdraw the COLs for Summer Nuclear Units 2 and 3. On January 8, 2018, the Authority submitted a letter in response to this request in which the Authority requested, among other things, that the NRC not take action for 180 days or until such time that the Authority could evaluate any risks it could incur by taking on the nuclear licenses.

Based on these considerations the Authority determined a fair value of zero as of December 31, 2018 for the non-fuel impaired Project assets.

With the suspension of construction of Summer Nuclear Units 2 and 3 the nuclear fuel material for the first core load of the units will no longer be needed or used in Units 2 and 3. Due to the nature of the Unit 2 and 3 fuel, it cannot be used as is at Summer Nuclear Unit 1. SCE&G performed an analysis to determine how this fuel might be disposed and the fair value of the fuel. The analysis considered both selling the fuel into the market and exchanging the fuel for material that can be used in Unit 1. SCE&G used estimated market prices as of December 31, 2017 obtained from nuclear fuel suppliers when estimating the value of the fuel. Using SCE&G's analysis the Authority had determined that the fair value of this fuel was 33.52% of the book value of the fuel, or $34.6 million (Authority's share), as of December 31, 2017. The remaining $68.5 million was written off as impaired.

Based on the results in determining the fair value, the write-off of Summer Nuclear Units 2 and 3 construction costs and nuclear fuel for the year ended December 31, 2017 totaled $4.211 billion.

During 2018 additional invoices related to Units 2 and 3 were received and other correcting entries were made to the Unit 2 and 3 costs. These amounts were part of the impaired assets and were charged to the Nuclear Regulatory Asset (See Footnote 1 – K - Other Regulatory Items). Market prices for Unit 2 and 3 fuel were estimated as of December 31, 2018 and based on these prices, no additional adjustments to the book value of the fuel were made.

2018 Developments Status of COLs. On January 28, 2019 the Authority Board approved a resolution authorizing the Interim President and CEO to consent to SCE&G's request to terminate the Summer Nuclear Units 2 and 3 COLs. That consent was conveyed to the Nuclear Regulatory Commission in a letter dated January 29, 2019. (See Footnote 15 - Subsequent Events.)

Reactor Coolant Pump Transfer to China. In February 2018, SCE&G and the Authority sold one reactor coolant pump planned for use in Summer Nuclear Unit 2 to Westinghouse for use in the China Project, Haiyang Unit 2. The Authority's 45% share of the proceeds was approximately $6.5 million and the resulting gain was recorded as a regulatory liability (See Footnote 1- K Other Regulatory Items.).

Sales Tax Audit and Proposed Assessment. On January 26, 2018 the SC DOR notified SCE&G that the sales and use tax returns for the Summer Nuclear 2&3 project have been assigned for a sales and use tax audit. During a meeting on February 8th, the DOR clarified its position that, because the VC Summer 2&3 project had been abandoned and the manufacturing facility was not completed and would not produce electricity, the materials for the Project were not tax-exempt and sales taxes were due on previously tax exempt purchases. On May 31, 2018, the SC DOR notified SCE&G that, since all of the information requested of SCE&G was not provided; a Proposed Notice of Assessment was generated. The full assessment, which was based on information obtained by the department, was for $421 million. On October 1, 2018 Santee Cooper's outside counsel submitted on Santee Cooper's behalf a Protest to Notice of Proposed Assessment Department File No. 020800475. As of December 31, 2018, Santee Cooper continues to dispute the position that sales taxes are due and owing.

Right of Entry; Maintenance, Preservation and Documentation Plan; and Warehoused Equipment Moved. On June 25, 2018, SCE&G and the Authority signed a Right of Entry Agreement allowing the Authority to begin implementation of a Maintenance, Preservation, and Documentation Plan (MPD) to preserve the equipment for the Project. The Authority contracted with Fluor Inc. to perform this scope of work to assess the equipment condition and to maintain the high value equipment. Fluor Inc. began this scope of work at the Project on July 2, 2018. Additionally, all assets stored in two large offsite warehouses were relocated to the Project site in 2018.

Switchyard True-Up. Included in the Summer Nuclear Units 2 and 3 transmission related assets that were not impaired were certain switchyard assets. During 2018 the parties determined that the ownership interest in these assets needed to be adjusted and began negotiating an agreement to adjust the percentages and true-up the charges. As of December 31, 2018 that adjustment was reasonably estimated and a receivable from SCE&G to the Authority in the amount of $2.7 million was recorded. The Authority expects to complete this effort in the second quarter of 2019.

Forbearance Agreement and Next Steps. On December 13, 2018, SCE&G and the Authority executed an agreement styled a "Forbearance Agreement" whereby SCE&G reaffirmed its irrevocable waiver of any and all rights in the Forbearance Assets, defined generally as Summer Nuclear Units 2 and 3; ancillary facilities; intellectual property; equipment and materials on-site and off-site including, without limitation assets, materials and equipment that are affixed to the real property at the site but are capable of being removed. Excluded from the definition of Forbearance Assets is the underlying real property; certain specifically identified assets excluded from the abandonment prior to December 31, 2017; substation and switchyard assets; the old NND Building and nuclear fuel. The Forbearance Agreement requires SCE&G seek, within 30 days of the execution of the agreement, approval of the Public Service Commission of South Carolina of the agreement and, during the same 30 day period, take reasonable efforts to obtain the release of any security interest or mortgage attached to the Forbearance Asset.

The execution of the Forbearance Agreement and its successful approval and implementation will set the foundation for possible domestic and international sales of equipment, commodities and plant components covered by the agreement.

Regulatory Accounting Treatment

Nuclear Asset Impairment. On January 22, 2018, the Board approved the use of regulatory accounting for the $4.211 billion impairment write down. The majority of the Project was financed with borrowed funds. For rate-making purposes, the Authority includes the debt service on these borrowed funds in its rates. As such, the impairment will be recorded as a regulatory asset and amortized through November 2056 to align with the associated debt principal payments. In the event the principal maturities change materially the amortization will be adjusted to better align with the new maturities. In 2018, there was a decrease of $8.3 million charged to the nuclear impairment regulatory asset for adjustments after year end 2017, as well as amortization of $4.9 million.

Post Project Suspension Interest Expense. On December 11, 2017 the Board issued a resolution authorizing the use of regulatory accounting to defer a portion of the post suspension Project interest. With the cessation of capitalized interest and the timing of the suspension the Authority would be unable to collect a portion of the post suspension Project interest in rates. The regulatory asset for post suspension nuclear interest totaled $37.1 million and will be amortized through November 2056 to align with the principal payments on the debt used to pay the interest.

Toshiba Settlement Agreement. The Board of Directors also approved a resolution dated December 11, 2017, authorizing using regulatory accounting to defer recognition of income from the Settlement Agreement. The Authority recorded a regulatory deferred inflow of $898.2 million. The deferred inflow will be amortized to align with the manner in which debt service is reduced as a result of using the proceeds.

The following table summarizes nuclear related regulatory items:

Regulatory Item	Classification	Original Amount	2018 Amortization	2018 Changes	2018 Ending Balance
Nuclear impairment	Asset	$ 4.211 billion	($ 4.9 million)	($ 8.1 million)	$ 4.198 billion
Nuclear post-suspension interest	Asset	$ 37.1 million			$ 37.1 million
Toshiba Settlement Agreement	Deferred Inflow	$ 898.2 million	($ 176.6 million)	$ 10.7 million	$ 732.3 million

Note 8 – Leases

Capital Leases
The Authority (Lessor) has a capital lease (the "Office Site Ground Lease Agreement") with Volvo Car USA, LLC (Lessee) covering a ground lease for an improved office site and associated acreage. The lease term is 20 years with annual payments of $404,166.59 due each January 1st, starting January 1, 2018. The sum of the minimum lease payments total $8.1 million and include site work of $5.9 million, land of $0.5 million and interest of $1.7 million (based on the 20-year Treasury Bill on the effective rate of 2.58%). Volvo Car USA, LLC has options to purchase the office site as follows:

1. At any time until the expiration of the capital lease term, Volvo Car USA, LLC shall have a purchase option, the price of which shall be determined as: (i) the amount sufficient to repay in full the land purchase price of $0.5 million; plus (ii) the costs and expenses incurred by the Authority for the site preparation of $5.9 million; plus (iii) interest added at 2.58% per annum; accruing from the work completion date through and until the date of payment by Volvo Car USA, LLC to Santee Cooper of the option purchase price; less (iv) the amount of rent paid by Volvo Car USA, LLC to the Authority as of the date of payment by Volvo Car USA, LLC of the option purchase price.
2. At expiration of the capital lease and if Volvo Car USA, LLC has paid all rent in accordance with the capital lease, Volvo Car USA, LLC shall have a purchase option with an option purchase price of $1.

Total minimum lease payments to be received from Volvo Car USA, LLC as of December 31, 2018 are as follows:

Year Ending December 31,	Minimum Lease Payments (Thousands)
2019	$ 404
2020	404
2021	404
2022	404
2023	404
Thereafter	5,659
Total	$ 7,679

In the period covering the 1950s – 1970s, the Authority entered into several long term leases with Central for Transmission and other assets at the expiration of which, title to those assets would be transferred to the Authority. The final lease term ended in 2014. Work to transfer title of these assets is under way, but has not yet been completed as of December 31, 2018.

Operating Leases

Hydroelectric generating facility lease (Buzzard's Roost):

- Obligation is $600,000 per year plus operating expenses
- Lease will terminate on March 3, 2020.

Note 9 – Contracts with Electric Power Cooperatives

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 20 distribution cooperatives which are members of Central. Power supply and transmission services are provided to Central in accordance with a power system coordination and integration agreement ("the Coordination Agreement"). Under the Coordination Agreement, the Authority is the predominant supplier of energy needs for Central, excluding amounts supplied by Duke to the Upstate Load which is defined below, energy Central receives from the Southeastern Power Administration ("SEPA") and negligible amounts generated and purchased from others.

Central, under the terms of the Coordination Agreement, has the right to audit costs billed to them. Any differences found as a result of this process are accrued if they are probable and estimable. To the extent that differences arise, prospective adjustments are made to the cost of service and are reflected in operating revenues in the accompanying Statements of Revenues, Expenses and Changes in Net Position. Such adjustments in 2018 and 2017 were not material to the Authority's overall operating revenue.

In September 2009, the Authority and Central entered into an agreement which, among other things, permitted Central to purchase the electric power and energy requirements necessary to serve five of its member cooperatives, (Blue Ridge Electric Cooperative, Inc., Broad River Electric Cooperative, Inc., Laurens Electric Cooperative, Inc., Little River Electric Cooperative, Inc. and York Electric Cooperative, Inc.) who are directly connected to the transmission system of Duke ("the Upstate Load"), from a supplier other than the Authority. The Upstate Load began transitioning to the new supplier, Duke, in 2013. The load transition was complete on January 1, 2019 and amounted to approximately 900 MW.

In 2013 the Central and Authority Boards approved an Amendment to the Coordination Agreement. As part of this Central agreed to extend their rights to terminate the agreement until December 31, 2058. The Coordination Agreement includes a 10-year rolling notice provision. For a termination date of December 31, 2058, a party must give notice of termination no later than December 31, 2048. The Coordination Agreement provides for closer cooperation on planning of future resources, gives Central the ability to "opt-out" of future generation resources, and provides for cost recovery of all resources completed or under construction as of the amendment effective date, including Summer Nuclear Units 2 and 3. Certain matters between the Authority and Central relating to the nuclear project are the subject of litigation, however, the parties continue to conduct business pursuant to the terms of the Coordination Agreement.[2]

Note 10 – Commitments and Contingencies

Budget - The Authority's 2019 three-year capital budget is as follows:

Years Ending December 31,		2019		2020		2021
				(Millions)		
Environmental Compliance [1]	$	111.8	$	44.9	$	32.0
General Improvements and Other [2]		185.1		179.1		195.2
Total capital budget [3]	$	296.9	$	224.0	$	227.2

Budget Assumptions:
[1] The CCR and ELG environmental regulations are undergoing agency review and are subject to court challenges. Given the significant uncertainty about the outcome and eventual requirements, we may not have budgeted sufficient funds depending on final regulations for all potential costs at this time.
[2] Other includes Camp Hall and renewables.
[3] Will be financed by internal funds or debt.

Purchase Commitments - The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2018. The disclosure of minimum obligations (including market re-opener contracts) shown below is based on the Authority's contract rates and represents management's best estimate of future expenditures under current long-term arrangements. Additional arrangements are expected to meet the Authority's full demand.

Years Ending December 31,		With Re-openers (All Tons) [1]		Without Re-openers (Fixed Tons) [2]
		(Thousands)		
2019	$	180,276	$	180,276
2020		123,293		123,293
2021		126,910		108,160
2022		0		0
Total	$	430,479	$	411,729

[1] Includes tons which the Authority can elect not to receive.
[2] Includes tons which the Authority must receive.

[2] See Footnote 10 – Legal Matters for a description of a litigation under the subheading *"Jessica S. Cook et al. v. Santee Cooper, Santee Cooper's Board of Directors (certain former and current Directors named), SCE&G, Palmetto Elec. Coop., & Central Elec. Pwr. Coop"* for a description of Central's cross-claim against the Authority seeking, among other things, a declaratory judgment that Santee Cooper breached the Coordination Agreement.

The Authority has the following outstanding obligations under existing long-term capacity and purchased power contracts as of December 31, 2018:

Contracts with Minimum Fixed Payment Obligations[1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	1985	17 Years	$ 0

[1] Obligation reflects the Authority's position that the Rediversion contract does not require a capacity payment beyond the 30 year period which ended on March 23, 2015. (See Footnote 10 – Legal Matters Subsection)

Contracts with Power Receipt and Payment Obligations [1]

Number of Contracts	Delivery Beginning	Remaining Term	Obligations (Millions)
1	2010	7 Years	$ 137.8
2	2013	25 Years	518.0
1	2013	15 Years	6.6

[1] Payment required upon receipt of power. Assumes no change in indices or escalation.

The Authority purchases network integration transmission service through a transmission agreement with SCE&G. This network transmission service is used to serve wholesale customers who are not in the Authority's direct-served territory; the Authority is obligated for costs associated with these transmission agreements. The table below shows the transmission obligations in 2019 and the total transmission obligations for 2019-2029. Note that the transmission obligations associated with the Upstate Load will end in 2019 (concurrent with the end of the transition period). The Authority is no longer responsible for purchasing transmission service for the Upstate Load served by the new supplier. The remaining wholesale customer obligations below represent projected transmission amounts through the term of the current contracts.

Transmission Obligations

	2019	2020-2029
	(Thousands)	
Other Customers	$ 3,268	$ 35,510
Total	$ 3,268	$ 35,510

CSX Transportation, Inc. (CSX) provides substantially all rail transportation service for the Authority's Cross and Winyah coal-fired generating stations. The Authority also interchanges with some short line railroads via CSX for the movement of coal as well. The CSX contract, effective January 1, 2011, and extended per amendment effective January 1, 2018, continues to apply a price per ton of coal moved, along with a mileage based fuel surcharge and minimum tonnage obligation.

The Authority has commitments for nuclear fuel, nuclear fuel conversion, enrichment and fabrication contracts for Summer Nuclear Units 1, 2 and 3. As of December 31, 2018, these contracts total approximately $136.5 million over the next 16 years.

The contract obligations for the Rainey Generating Station Long-Term Parts and Long-Term Service Contract with General Electric International, Inc. ("GEII") were fulfilled in 2018. All covered units have reached the "performance end date" and there are no remaining financial commitments for this agreement.

The Authority successfully negotiated a Contractual Service Agreement with GEII, effective March 2016 that covers all units on the Rainey plant site since fulfilling the obligations under the Long-Term Parts and Long-Term Service Contract in 2018. The Contractual Service Agreement provides unplanned maintenance coverage, rotor replacement and auxiliary parts replacement in addition to a CPM, initial spare parts, parts and services for specified planned maintenance outages, remote monitoring and diagnostics of the turbine generators and combustion tuning for the gas turbines. Based on the latest approved fuel forecast, the contract term extends through 2027 and the Authority's estimated remaining commitment on the contract is $99.2 million, including escalation.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation to supply gas transportation needs for its Rainey Generating Station. The service agreement is for 80,000 dekatherms per day of firm capacity. Additionally, for a term beginning November 1, 2017 through December 31, 2020, the Authority has firm capacity of an additional 25,000 dekatherms through a delivered natural gas agreement via TEA.

Byproducts**-** Coal combustion products ("CCP"), which include fly ash, bottom ash, and flue gas desulfurization products such as gypsum, are produced when coal is burned to generate electricity. The Authority has entered into contracts for the beneficial use of CCPs and continually looks for new markets. The Authority supplies and delivers drywall quality gypsum to American Gypsum Company ("AG") in Georgetown, South Carolina under a long term contract that includes a minimum and maximum supply boundary. The gypsum is primarily sourced from synthetic gypsum produced at the Cross Generating Station ("CGS") and Winyah Generating Station ("WGS"). Currently and under projected dispatch assumptions, gypsum produced at CGS and WGS does not meet required minimums, and shortfalls are obtained from several external sources of both natural and synthetic gypsum. Sources may vary based on availability and cost. Natural gypsum is currently purchased and delivered from International Materials Inc. Synthetic gypsum is currently purchased from Cameron Ag Products, LLC ("Cam Ag"). Cam Ag provides this source via rail from Plant Bowen in Georgia to Jefferies Station.

In February 2019, the Authority entered into a contract with Meridian WGS, LLC ("Meridian") to convert low quality gypsum slurry stored at WGS into drywall quality gypsum using a proprietary process. The Authority has also entered into a lease agreement with Meridian that will allow it to construct its facility at WGS. Pending Meridian obtaining financing for construction, it will permit, construct and operate the conversion facility at WGS to produce drywall quality gypsum that can be used to meet contracted obligations. The conversion process allows waste material to be converted and beneficially used as drywall quality gypsum while providing an environmentally responsible and low cost option to close the slurry pond.

Additionally, ponded ash is reclaimed from the Authority's ash ponds for use in the cement industry, dry fly ash is recovered directly from the operating units for use in the cement industry, and bottom ash is beneficially used by concrete block manufacturers to produce concrete block. The Authority has multiple beneficial use agreements to facilitate beneficial use activities, one of which is the STAR Processed Fly Ash Operating and Sales Agreement between the Authority and The SEFA Group, Inc. ("SEFA"). Pursuant to this Agreement, Santee Cooper supplies dry fly ash and/or ponded ash to SEFA who processes it in their staged turbulent air reactor ("STAR") unit to produce a high quality ash which they market to the concrete industry.

Risk Management **-** The Authority is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; business interruption; and errors and omissions. The Authority purchases commercial insurance to cover these risks, subject to coverage limits and various exclusions. Settled claims resulting from these risks did not exceed commercial insurance coverage in 2018. Policies are subject to deductibles ranging from $500 to $2.0 million, with the exception of named storm losses which carry deductibles from $2.0 million up to $5.0 million. Also a $1.4 million general liability self-insured layer exists between the Authority's primary and excess liability policies. During 2018, there were minimal payments made for general liability claims.

The Authority is self-insured for auto, worker's compensation and environmental incidents that do not arise out of an insured event. The Authority purchases commercial insurance, subject to coverage limits and various exclusions, to cover automotive exposure in excess of $2.0 million per incident. Estimated exposure for worker's compensation is based on an annual actuarial study using loss and exposure information valued as of June 30, 2018. In addition, there have been no third-party claims regarding environmental damages for 2018 or 2017.

Claim expenditures and liabilities are reported when it is probable that a loss has occurred and the amount of the loss can be reasonably estimated. The amount of the self-insurance liabilities for auto, dental, worker's compensation and environmental remediation is based on the best estimate available. Changes in the reported liability were as follows:

Years Ended December 31,	**2018**	2017
	(Thousands)	
Unpaid claims and claim expense at beginning of year	**$ 1,680**	$ 2,019
Incurred claims and claim adjustment expenses:		
Add: Provision for current year events	**1,796**	2,572
Less: Payments for current and prior years	**2,401**	2,911
Total unpaid claims and claim expenses at end of year	**$ 1,075**	$ 1,680

The Authority pays insurance premiums to certain other State agencies to cover risks that may occur in normal operations. The insurers promise to pay to, or on behalf of, the insured for covered economic losses sustained during the policy period in accordance with insurance policy and benefit program limits. The State assumes all risks for the following:

(1) claims of covered employees for health benefits covered through South Carolina Public Employee Benefit Authority ("PEBA") Insurance Benefits; not applicable for worker's compensation injuries; and
(2) claims of covered employees for basic long-term disability and group life insurance benefits (PEBA Insurance Benefits and PEBA Retirement Benefits).

Employees elect health coverage through the State's self-insured plans with the exception of employee dental insurance for which the Authority is self-insured. Risk exposure for the dental plan is limited by plan provisions. Additional group life and long-term disability premiums are remitted to commercial carriers. The Authority assumes the risk for claims of employees for unemployment compensation benefits and pays claims through the State's self-insured plan.

Nuclear Insurance - The maximum liability for public claims arising from any nuclear incident has been established at $14.073 billion by the Price-Anderson Indemnification Act. This $14.073 billion would be covered by nuclear liability insurance of $450.0 million per reactor unit, with potential retrospective assessments of up to $137.6 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed $20.5 million per incident, per year). Based on its one-third interest in Summer Nuclear Unit 1, the Authority could be responsible for the maximum assessment of $45.9 million, not to exceed approximately $6.8 million per incident, per year. This amount is subject to further increases to reflect the effect of (i) inflation, (ii) the licensing for operation of additional nuclear reactors and (iii) any increase in the amount of commercial liability insurance required to be maintained by the NRC. Additionally, SCE&G and the Authority maintain, with Nuclear Electric Insurance Limited (NEIL), $1.500 billion primary and $1.250 billion excess property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. SCE&G and the Authority also maintain an excess property insurance policy with European Mutual Association for Nuclear Insurance (EMANI) to cover property damage and outage costs up to $415.0 million resulting from an event of non-nuclear origin. SCE&G and the Authority also maintain accidental outage insurance to cover replacement power costs (within policy limits) associated with an insured property loss. In addition to the premiums paid on these policies, SCE&G and the Authority could also be assessed a retrospective premium, not to exceed ten times the annual premium of each policy, in the event of property damage to any nuclear generating facility covered by NEIL. Based on current annual premiums and the Authority's one-third interest, the Authority's maximum retrospective premium would be approximately $7.4 million for the primary policy, $3.5 million for the excess policies and $1.8 million for the accidental outage policy.

SCE&G and the Authority maintained builder's risk insurance for the Summer Nuclear Units 2 and 3 construction. The builder's risk policy, carried by NEIL, was cancelled by SCE&G effective December 27, 2017 and carries a potential retrospective premium of approximately $42.0 million for six years from the cancellation date. Based on the Authority's current 45 percent ownership interest, the Authority's maximum retrospective premium would be approximately $18.9 million. The marine cargo/transit policy coverage was cancelled by SCE&G on January 31, 2018.

The Authority is self-insured for any retrospective premium assessments, claims in excess of stated coverage or cost increases due to the purchase of replacement power associated with an uninsured event. Management does not expect any retrospective assessments, claims in excess of stated coverage or cost increases for any periods through December 31, 2018.

Clean Air Act - The Authority endeavors to ensure that its facilities comply with applicable environmental regulations and standards.

In addition to the existing Clean Air Act ("CAA") Federal Acid Rain Program, the Environmental Protection Agency ("EPA") has implemented the Cross State Air Pollution Rule ("CSAPR") for SO2 and NOx emissions, effective January 1, 2015. The CSAPR rule does not negatively impact the Authority.

The Authority continues to review proposed greenhouse gas regulations and legislation to assess potential impacts to its operations. In 2010, EPA finalized the Prevention of Significant Deterioration ("PSD") Tailoring Rule for regulating greenhouse gases through the PSD permitting process under the existing CAA. EPA issued Best Available Control Technology ("BACT") Guidance in 2010 for use under the rule effective July 1, 2011. In 2014, EPA proposed three separate rules for (1) new, (2) existing, and (3) modified and reconstructed Electric Generating Units ("EGU"). On August 3, 2015, EPA announced a final rule to regulate carbon dioxide emissions from power plants entitled the Clean Power Plan ("CPP"). The final rule was published in the Federal Register on October 23, 2015. On February 9, 2016, the Supreme Court in a 5-4 vote granted an emergency stay of the CPP. In 2017, EPA proposed to repeal and replace the CPP, and in 2018 EPA issued a draft replacement rule, the Affordable Clean Energy ("ACE") Rule. This draft rule provides that the best system of emission reduction ("BSER") for existing units is based on heat rate improvement measures. The comment period for this draft rule ended on October 30, 2018, and EPA is currently reviewing comments with no projected rule completion date. The CPP stay remains in effect.

Through the maximum achievable control technology ("MACT") regulatory process, EPA has promulgated Utility MACT regulations to reduce the emissions of mercury and other hazardous air pollutants ("HAPs") from coal- and oil-fired electric utility steam boilers. The final MACT rule, renamed the Mercury and Air Toxics Standard ("MATS"), became effective April 16, 2015. The MATS rule includes emissions limitations for mercury, acid gases and other HAPS from existing and new coal-fired and oil-fired electric utility steam units. This is EPA's first national standard to reduce mercury and other air toxins from coal-fired and oil-fired power plants. On December 26, 2018, in response to a U.S. Supreme Court ruling, EPA proposed to determine that it is not "appropriate and necessary" to regulate HAP emissions from power plants under Section 112 of the Clean Air Act based on the cost of compliance relative to the HAP benefits of the regulation. However, the emissions standards and other requirements of the MATS rule would remain in place, since EPA is not proposing to remove coal-fired and oil-fired power plants from the list of sources that are regulated under Section 112 of the Act. Comments on this proposal are due within 60 days of its publication in the Federal Register. All Santee Cooper coal units are in compliance with the MATS rule.

On November 26, 2014, EPA completed the federally mandated 5-year review of the national ambient air quality standards ("NAAQS") and proposed a revised (more stringent) ground-level ozone standard range. This applies to both the primary (public health) and secondary (public welfare) standards. On October 1, 2015, EPA announced that the new NAAQS for ozone would be set at 70 parts per billion. This applies to both the primary and secondary ozone standards. On December 6, 2018, EPA's final state implementation plan ("SIP") requirements in nonattainment areas were published in the Federal Register. However, EPA projections, based on current monitoring networks, are that all counties in South Carolina will meet the revised standard without taking additional action to reduce emissions.

Safe Drinking Water Act - The Authority continues to monitor regulatory issues impacting drinking water systems at the Authority's regional water systems, generating stations, substations and other auxiliary facilities. DHEC has regulatory authority of potable water systems in South Carolina under The State Primary Drinking Water Regulation, R.61-58; the Authority endeavors to manage its potable water systems in compliance with R.61-58.

Clean Water Act - The Clean Water Act ("CWA") prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System ("NPDES") permit program. DHEC has been delegated NPDES permitting authority by the EPA and administers the NPDES permit program for the State.

Wastewater discharges from the generating stations and the regional water plants are governed by NPDES permits issued by DHEC. Further, the storm water from the generating stations must be managed in accordance with the State's NPDES Industrial General Permit for storm water discharges. Storm water from construction activities must also be managed under the State's NPDES General Permit for storm water discharges from construction activity. The Authority endeavors to operate in compliance with these permits.

The EPA issued their final rule regarding Section 316(b) of the CWA on August 15, 2014. The rule establishes requirements for cooling water intake structures ("CWISs") at existing facilities. Section 316(b) of the CWA requires that the location, design, construction and capacity of CWISs reflect the best technology available (BTA) for minimizing adverse environmental impacts. Santee Cooper will continue to work with the regulatory agencies on implementation as required. The Authority believes compliance costs are not significant.
The EPA regulates oil spills prevention and preparedness under the CWA, Spill Prevention Control and Counter-measures ("SPCC"). These regulations require that applicable facilities, which include generating stations, substations and auxiliary facilities, maintain SPCC plans to meet certain standards. The Authority continually works to be in compliance with these regulations.

The EPA has also been developing a new rule specifying requirements for spill prevention and preparedness for chemicals stored in aboveground storage tanks. Under a consent decree issued on February 16, 2016, EPA is required to create new regulations that establish procedures, methods, equipment, and other requirements to prevent hazardous substance discharges. On June 25, 2018, EPA published a proposed rule that determined no additional actions are necessary to prevent these discharges. The public comment period for the proposed rule closed on August 24, 2018, and EPA is expected to take final action by mid- to late-2019. The Authority will continue to monitor the rule as it is being developed to determine the impacts.

The NPDES Steam Electric Effluent Limitation Guidelines ("ELG") rule became effective on January 4, 2016. It applies to all existing steam electric units greater than 50 MWs (other than oil-fired) and is to be phased in as soon as possible beginning November 1, 2018, but no later than December 31, 2023, via the reissuance of generating station NPDES Permits. New standards included a prohibition on discharge of bottom ash sluice water and stringent effluent limitations on flue gas desulfurization wastewater. In 2017, EPA announced its intent to conduct a new rulemaking which may revise some elements of the rule, and postponed the earliest compliance dates by two years to November 1, 2020; in practice, compliance with the ELG rule is integrated with the CCR rule (discussed further below). Portions of the rule that impact the Authority have been stayed, and the revised rule has not yet been published but is expected within the next six months.

The 2015 "Waters of the U.S." rule ("WOTUS"), which expands the federal jurisdiction under the Clean Water Act and would require additional permitting and mitigation for new construction or expansion projects regulated as Waters of the U.S., remains under judicial and agency review. The rule has had numerous legal challenges that have prevented it from going into effect in South Carolina at this time. A revised rule was released as a prepublication version on December 11, 2018. It will have a 60-day comment period once it is published in the Federal Register. The Authority's review of this new rule is ongoing, and we will continue to monitor further developments for potential impacts.

Hazardous and Non-Hazardous Substances, Solid Wastes and Coal Combustion Byproducts - Section 311 of the CWA imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") provides for the reporting requirements to cover the release of hazardous substances into the environment. Additionally, the EPA regulations under the Toxic Substances Control Act ("TSCA") impose stringent requirements for labeling, handling, storing and disposing of polychlorinated biphenyls (PCBs) and associated equipment.

Under the CERCLA and Superfund Amendments and Reauthorization Act ("SARA"), the Authority could be held responsible for damages and remedial action at hazardous waste disposal facilities utilized by it, if such facilities become part of a Superfund effort. Moreover, under SARA, the Authority must comply with a program of emergency planning and a "Community Right-To-Know" program designed to inform the public about more routine chemical hazards present at the facilities. Both programs have stringent enforcement provisions. The Authority endeavors to comply with the applicable provisions of TSCA, CERCLA and SARA, but it is not possible to determine if some liability may be imposed in the future for past waste disposal or compliance with new regulatory requirements. The Authority strives to comply with all aspects of the Resource Conservation and Recovery Act (RCRA) regarding appropriate disposal of hazardous wastes.

The Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash, scrubber sludge and gypsum. These wastes, known as Coal Combustion Residuals ("CCRs"), are exempt from hazardous waste regulation under the RCRA. On April 17, 2015, EPA published a rule that establishes a comprehensive set of requirements for the management and disposal of CCRs. The rule regulates CCRs as a RCRA Subtitle D, nonhazardous waste and had an effective date of October 19, 2015. In 2018 the rule was modified (the CCR Remand Rule) and additional future rule modifications are anticipated. The Authority continues to comply with the CCR rule, including through groundwater monitoring and internet postings of CCR rule reports. Long-term compliance plans include pond closures and utilization of Class 3 landfills at Cross and Winyah for disposal of CCRs. Beneficial use of ash and gypsum results in removal of CCRs from ponds to support closure and fewer CCRs being disposed of in the on-site landfills. Compliance costs for the CCR rule and related ELG rule will be determined as the requirements are clarified.

On November 2, 2018, DHEC issued a Permit to operate the newly constructed Class 3 landfill at Winyah Generating Station. The on-site landfill is now in operation.

The Authority has retired units and ancillary facilities at both the Grainger and Jefferies Generating Stations. Closure plans for both the Grainger and the Jefferies ash ponds have been approved by DHEC and closure through excavation, beneficial use, or landfilling material in a class 3 landfill is in progress.

The Solid Waste Disposal Act and Energy Policy Act give EPA authority to regulate Underground Storage Tanks (USTs). EPA regulations concerning USTs are contained in 40 CFR Parts 280-282. DHEC has granted state program approval in 2002 and regulates USTs under R. 61-92, Part 280 dated 2008. This regulation provides requirements for the design, installation, operation, closure, release detection, reporting and corrective action and financial responsibility. The Authority's corporate policy number 2-11-02 provides guidance for the proper management and monitoring of USTs for environmental and regulatory compliance.

Pollution Remediation Obligations – The Authority follows GASB 49 which addresses standards for pollution (including contamination) remediation obligations for activities such as site assessments and cleanups. GASB 49 does not include standards for pollution remediation obligations that are addressed elsewhere. Examples of obligations addressed in other standards include pollution prevention and control obligations for remediation activities required upon the retirement of an asset, such as ash pond closure and post-closure care and nuclear power plant decommissioning.

No pollution remediation liabilities were recorded for the years ended December 31, 2018 and 2017.

FERC Hydroelectric License - The Authority operates its Jefferies Hydro Station and certain other property, including the Pinopolis Dam on the Cooper River and the Santee Dam on the Santee River, which are major parts of the Authority's integrated hydroelectric complex, under a license issued by the FERC pursuant to the Federal Power Act ("FPA"). The project is currently undergoing relicensing and a Notice of Intent ("NOI") to relicense was filed with the FERC on November 13, 2000. The final license application was filed March 15, 2004. Due to a number of additional Information Requests, the relicensing process has extended beyond the March 31, 2006 license expiration date. The FERC has issued a standing annual license renewal until a final license is issued. The FERC issued its Final Environmental Impact Statement ("EIS") in October 2007. The South Carolina Department of Natural Resources, the U.S. Fish and Wildlife Service, and the Authority have jointly signed and filed a settlement agreement with the FERC that among other things, identifies fish passage and outflow guidelines during the term of the next license. The National Marine Fisheries Service ("NMFS") chose not to join in the settlement agreement and has submitted mandatory fishway conditions under §18 of the FPA and flow recommendations under §10 of that Act that are inconsistent with the settlement agreement. In November 2007, FERC requested that NMFS undertake an Endangered Species Act ("ESA") Section 7 consultation with regard to the relicensing project. In July of 2010, as a function of the required Section 7 consultation, NMFS submitted a draft biological opinion containing recommendations for the endangered shortnose sturgeon. The recommendations, if adopted, would result in substantial additional costs for operating the project. The Authority provided a response to those recommendations in September 2010. The Authority cannot predict when NMFS will issue a final biological opinion or the final outcome of the FERC relicensing process.

Homeland Security - The Department of Homeland Security ("DHS") was established by the Homeland Security Act of 2002, a portion of which relates to anti-terrorism standards at facilities which store or process chemicals. The Chemical Facility Anti-Terrorism Standards (CFATS) program identifies and regulates high-risk chemicals facilities to ensure they have security measures in place to reduce the risk associated with these chemicals. The Authority has been proactive in striving to comply with these evolving regulations by conducting valid threat and risk assessments to the facilities regulated by the CFATS program, also referred to as 6 CFR, Part 27. Once completed, the assessments become sensitive, federally controlled documents and are stored in accordance with all federal and state guidelines attendant to critical infrastructure information protection.

Legislative Matters - On June 29, 2018, the South Carolina General Assembly ("General Assembly") ratified a State budget for FY 2018-2019, which runs from July 1 to June 30. The State budget included a proviso addressing Santee Cooper, also known as the South Carolina Public Service Authority. Part 1B Proviso 117.162 established a Public Service Authority Evaluation and Recommendation Committee ("Evaluation Committee") comprised of the Governor, four SC Senators and four SC House Members.

An objective of the Evaluation Committee is to determine a manner in which the General Assembly may best protect ratepayers and taxpayers in regard to Santee Cooper. This includes analyzing whether selling Santee Cooper is in the best interest of the State and Santee Cooper's customers or whether Santee Cooper should be retained by the State.

From August 7, 2018 to February 6, 2019, the Evaluation Committee held six meetings. The Evaluation Committee hired ICF International, Inc. ("ICF") to assist the Evaluation Committee with its review and to facilitate a process to receive and evaluate non-binding indicative bid proposals for the full purchase of Santee Cooper, to receive alternative proposals, and to conduct a valuation of Santee Cooper. On February 1, 2019, ICF issued its report to the Evaluation Committee. The SC General Assembly is now expected to continue its review of Santee Cooper which includes, among other things, the consideration of various alternatives for Santee Cooper such as managing or restructuring Santee Cooper or selling portions of its assets.

On February 21, 2019, the South Carolina Senate announced the creation of the Select Committee on Santee Cooper. The Senate has not yet set a date for the first meeting of the Select Committee.

The General Assembly is scheduled to meet from January 8, 2019 to May 9, 2019. Legislation may be introduced that impacts Santee Cooper's operations. Santee Cooper will be educating and informing the General Assembly of the impact of any relevant legislation that may impact its customers and operations.

Legal Matters - Except as noted below, there are no actions, suits, or governmental proceedings pending or, to the knowledge of the Authority, threatened before any court, administrative agency, arbitrator or governmental body which would, if determined adversely to the Authority, have a material adverse effect on its financial condition.

Pee Dee Class Action. A purported class action was filed by George Hearn on behalf of the Authority's retail customers (case no. 2017-CP-26-5256 in Horry County, S.C.). The complaint contains a number of causes of action and allegations related to the Authority's decisions to construct and cancel construction of a coal-fired generation project in Florence County, South Carolina. The Authority's motion to dismiss was heard on September 27, 2018. No decision has been issued. However, even if determined adversely to the Authority, this action would not have a material adverse effect on the Authority's ability to transact its business or meet its obligations under the Revenue Obligation Resolution.

The Authority cannot predict the outcome of this matter.

Century Antitrust Suit. On January 30, 2017, Century Aluminum filed suit alleging violations of the Sherman Act, the Clayton Act, the South Carolina Unfair Trade Practices Act, and the South Carolina Antitrust Act (case no. 2:17-cv-00274-RMG in U.S. Dist. Court, Dist. of S.C., Charleston Division). On October 10, 2017 the court entered an order granting Santee Cooper's motion to dismiss based upon the state action immunity doctrine. Century filed a notice of appeal on the same day (case no.17-2192 in the U.S. Court of Appeals for the Fourth Cir.). On October 8, 2018, the parties agreed to settle this matter with Century dismissing its appeal, leaving the district court order in place.

*Santee Cooper v. U.S. Army Corps of Engineers***.** The Authority filed a claim against the COE seeking a determination that the COE Re-diversion Contract does not require Santee Cooper to credit the COE for a capacity value surcharge and that the COE owes Santee Cooper approximately 1.4 million in contract payments for 2015. The COE denied the claim, asserted the Authority was required to pay the credit, and that a credit in the amount of $716,874 was due to the COE for 2015. The Authority appealed the decision to the Armed Services Board of Contract Appeals ("ASBCA") and the COE counterclaimed. The parties have asked the ASBCA to determine the rights under the contract. If the ASBCA determines that no credit is required, the Authority will prevail at the Board level. If the ASBCA determines that a credit is required, the parties will be required to attempt to determine the amount of the credit due to the COE for the remainder of the contract. If the parties do not reach an agreement, the court will make a determination of the amount.

The parties briefed the issues in the summer of 2018 but no timetable for a decision has been provided by the ASBCA. The parties have attempted settlement discussions but have been unsuccessful.

Santee Cooper cannot predict the outcome of this matter.

Summer Nuclear Units 2 and 3 Class Actions. Five purported class actions were filed on behalf of individuals either directly or indirectly served by the Authority. The complaints contain a number of causes of action and allegations related to the Authority's decisions to construct and cancel construction of two nuclear generation units in Fairfield County, SC. The Authority cannot predict the outcome of these lawsuits. If determined adversely to the Authority, these actions may possibly have a material adverse effect on the Authority's ability to transact its business or meet its obligations under the Revenue Obligation Resolution.

- ***Hope Brown et al. v. Santee Cooper and SCANA*** (case no. 2017-CP-40-05409 in Richland County, S.C.): Plaintiffs filed a complaint on September 8, 2017; SCANA removed the case to the U.S. Dist., Dist. of S.C., Columbia Division on October 12, 2017 (case no. 3:17-2764-TLW); on November 14, 2017, Plaintiffs voluntarily dismissed this action.

- ***Chris Kolbe et al. v. Santee Cooper, Santee Cooper's Board of Directors (certain former and current Directors named), et al.*** (case no. 2017-CP-08-02009 in Berkeley County, S.C.): Plaintiffs filed an amended complaint on September 29, 2017; Santee Cooper and the Directors filed a motion to dismiss the amended complaint on November 22, 2017; Plaintiffs voluntarily dismissed this action on March 27, 2018.

- ***Christine Delmater et al. v. Santee Cooper, Lonnie Carter, et al.*** (case no. 3:17-cv-02563-TLW in the U.S. Dist. Court, Dist. of S.C., Columbia Division): Plaintiffs filed a second amended complaint on November 7, 2017; Santee Cooper and Carter filed motions to dismiss the second amended complaint on January 10, 2018; Plaintiffs voluntarily dismissed this action on May 18, 2018.

- ***Jessica S. Cook et al. v. Santee Cooper, Santee Cooper's Board of Directors (certain former and current Directors named), SCE&G, Palmetto Elec. Coop., & Central Elec. Pwr. Coop.*** (case no. 2017-CP-25-348 in Hampton County, S.C): Plaintiffs originally filed this putative class action on August 22, 2017 in connection with Santee Cooper's decision to suspend construction and SCE&G's decision to abandon construction of. Summer Nuclear Units 2 and 3. The Fourth Amended Complaint was filed on March 27, 2018. The proposed class includes all ratepayers of Santee Cooper who paid utility bills that included "pre-construction, capital, in-service, construction, interest, and other pre-operational costs associated with the V.C. Summer Nuclear Reactor Unit 2 and 3 Project from January 1, 2007, to the present." Two putative subclasses are proposed: (1) direct Santee Cooper customers and (2) cooperative customers who indirectly purchased from Santee Cooper.

  The Fourth Amended Complaint asserts various causes of action against Santee Cooper, its directors, SCE&G, SCANA, Central Electric Cooperative, and Palmetto Electric Cooperative. Plaintiffs assert five claims against Santee Cooper alone: (1) declaratory judgment that the rates were not statutorily authorized; (2) breach of contract and/or implied contract on behalf of direct customers; (3) unconstitutional taking; (4) violation of due process; and (5) breach of contract and/or implied contract on behalf of indirect customers. Plaintiffs assert two claims on behalf of direct customers against Santee Cooper's board members in their official capacities: (1) breach of statutory duties and (2) breach of fiduciary duties. Plaintiffs also assert claims for (1) breach of contract and/or implied contract against Central/Palmetto Electric and SCANA/SCE&G. Finally, Plaintiffs assert four claims against all defendants: (1) negligence; (2) unjust enrichment/money had and received; (3) constructive trust (over the Toshiba settlement funds, any sale profits, and previously-paid rates); and (4) equity.

  Central Electric Cooperative answered Plaintiffs' Fourth Amended Complaint and filed cross-claims against Santee Cooper: (1) declaratory judgment that Santee Cooper breached its statutory duties; (2) declaratory judgment that Santee Cooper breached the coordination agreement; and (3) constructive trust (over the Toshiba payment and Citibank payment). Central does not assert a claim for damages, but asks for 70% of the lump sum payment Santee Cooper received from Citibank through monetization of the Toshiba settlement based on Central's allegation that it bears approximately 70% of Santee Cooper's capital costs.

  Palmetto Electric Cooperative answered Plaintiffs' Fourth Amended Complaint and filed seven cross-claims against SCANA, SCE&G, Santee Cooper, and Santee Cooper's directors. Three of those cross-claims are asserted against all defendants: (1) negligence; (2) unjust enrichment; and (3) equity. Three cross-claims are asserted against Santee Cooper alone: (1) taking; (2) for a declaratory judgment that Santee Cooper breached its statutory duties for charging rates for facilities that are not used and useful; and (3) constructive trust over the Toshiba payment and Citibank payment. Finally, one cross-claim is asserted against Santee Cooper's Directors alone: for a declaratory judgment that Santee Cooper's directors breached their statutory duties for charging rates that are not just and reasonable.

Santee Cooper and the Directors' motions to dismiss Plaintiffs' Complaint, Central's cross-claims, and Palmetto's cross-claims were denied in November 2018. The following month, Santee Cooper filed cross-claims against SCE&G: (1) gross negligence, (2) breach of fiduciary duties, (3) breach of contract accompanied by bad faith, (4) waste, (5) contractual indemnification, and (6) equitable indemnification. On January 31, 2019, SCE&G filed a Motion to Dismiss or in the Alternative Stay and Compel Arbitration with regard to the cross-claims. Discovery is proceeding.

Relatedly, in June 2018, Santee Cooper filed a petition with the South Carolina Supreme Court (appellate case no. 2018-001172), asking it to exercise its original jurisdiction to address whether Santee Cooper must comply with the statute specifically requiring it to fix, maintain, and collect charges at rates sufficient to provide for payment of all its expenses, the conservation, maintenance and operation of its facilities, the payment of principal and interest on its debt, and the fulfillment of its obligations to holders of other bonds and other debt – including the costs, expenses and obligations associated with Summer Nuclear Units 2 and 3. Defendants named in this matter are those who have filed claims against Santee Cooper related to these issues (including Cook, Glibowski, Central Electric Power Cooperative, and Palmetto Electric Power Cooperative). On February 22, 2019, the Court issued its order denying Santee Cooper's petition.

The Authority cannot predict the outcome of this matter.

- ***Timothy Glibowski et al. v. SCANA, SCE&G, Santee Cooper, Kevin Marsh, Jimmy Addison, Stephen Byrne, Martin Phalen, Mark Cannon, Russell Harris, Ronald Lindsay, James Micali, and Lonnie Carter*** (case no. 9:18-cv-273-TLW in the U.S. Dist. Court, Dist. of S.C., Beaufort Division): Plaintiffs filed this putative class action in connection with the decision to abandon construction of Summer Nuclear Units 2 and 3. The Second Amended Complaint was filed on January 28, 2019. It includes two proposed classes: (1) SCANA customers and (2) Santee Cooper customers who were charged and paid advance charges for costs associated with the construction of the units from 2007 to the present.

  The Second Amended Complaint asserts RICO and RICO conspiracy claims against SCANA, SCE&G, SCANA's officers, Santee Cooper, and the following Santee Cooper employees: Lonnie Carter (retired), Marion Cherry, and Michael Crosby. It also asserts a takings claim against SCANA, SCE&G, and Santee Cooper. Plaintiffs seek actual damages, treble damages under RICO, and attorneys' fees.

  On September 4, 2018, Santee Cooper filed a motion asking the court to certify two questions to the S.C. Supreme Court: (1) whether Santee Cooper is required by law to fix, maintain, and collect charges at rates sufficient to provide for payment of all its expenses, the conservation, maintenance and operation of its facilities, the payment of principal and interest on its debt, and the fulfillment of its obligations to holders of bonds and other debt – including the costs, expenses, and obligations associated with V.C. Summer Units 2 and 3 and (2) whether Santee Cooper is immune from Plaintiffs' claims for money damages under the doctrine of sovereign immunity and the S.C. Tort Claims Act. No ruling has been made.

  The Authority cannot predict the outcome of this matter.

Petition in the Original Jurisdiction. Santee Cooper filed a petition for original jurisdiction and complaint in the original jurisdiction of the South Carolina Supreme Court on June 25, 2018 (appellate case no. 2018-001172), naming as defendants the parties in the *Cook* action: individual ratepayers, Central Electric Power Cooperative Inc., and Palmetto Electric Power Cooperative.

The Authority seeks a declaration it must raise revenues from its customers through rates at least sufficient to pay all of its costs and expenses, the conservation, maintenance, and operation of its facilities, payment of principal and interest on indebtedness, and to fulfill all agreements with and obligations to debtholders, including those related to Summer Nuclear Units 2 and 3. The Authority also requests an injunction against the defendants and all others from using the courts of South Carolina to alter, limit, or restrict Santee Cooper's ability to follow the covenant. Central filed a return to the petition, opposing Santee Cooper's request for the Supreme Court entertain the action in its original jurisdiction. Palmetto joined in Central's return. The individual ratepayers filed a separate return. Santee Cooper filed replies to all returns. The Court has not yet accepted or rejected Santee Cooper's petition.

The Authority cannot predict the outcome of this matter.

Summer Nuclear Units 2 and 3 Governmental Inquiries. Various executive-branch entities have requested information related to Summer Nuclear Units 2 and 3. Specifically, the Authority has received subpoenas for information from the U.S. Securities & Exchange Commission and the U.S. Department of Justice. It has also received information requests and directives to provide information from the Governor of South Carolina. The Authority also received legislative inquiries from the S.C. House of Representatives and the S.C. Senate. The Authority continues to comply and cooperate with these subpoenas, information requests and directives and legislative inquiries.

BP Amoco Chemical Co. On August 25, 2017, BP Amoco Chemical Co. made a claim for $9,709,506.00 as property damage and income loss sustained because of an unexpected outage at its BP Cooper River Chemical Plant (Berkeley County, S.C.) on May 4, 2017. It appears the unexpected outage occurred during a routine maintenance operation, resulting in in BP being without power for approximately 11 minutes. BP receives power from Santee Cooper pursuant to a service agreement, which limits liability. Santee Cooper denies liability. No action has been filed.

The Authority cannot predict the outcome of this matter.

Sales Tax – On January 26, 2018 the SC DOR notified SCE&G that the sales and use tax returns for the Summer Nuclear 2&3 project have been assigned for a sales and use tax audit. During a meeting on February 8th, the DOR clarified its position that, because the VC Summer 2&3 project had been abandoned and the manufacturing facility was not completed and would not produce electricity, the materials for the Project were not tax-exempt and sales taxes were due on previously tax exempt purchases. On May 31, 2018, the SC DOR notified SCE&G that, since all of the information requested of SCE&G was not provided; a Proposed Notice of Assessment was generated. The full assessment, which was based on information obtained by the department, was for $421 million. On October 1, 2018 Santee Cooper's outside counsel submitted on Santee Cooper's behalf a Protest to Notice of Proposed Assessment Department File No. 020800475. As of December 31, 2018, Santee Cooper continues to dispute the position that sales taxes are due and owing.

Note 11 – Retirement Plans

The South Carolina Public Employee Benefit Authority ("PEBA"), which was created July 1, 2012, administers the various retirement systems and retirement programs managed by its Retirement Division. PEBA has an 11-member Board of Directors, appointed by the Governor and General Assembly leadership, which serves as co-trustee and co-fiduciary of the systems and the trust funds. By law, the Budget and Control Board (restructured into the Department of Administration on July 1, 2015), which consists of five elected officials, also reviews certain PEBA Board decisions regarding the funding of the South Carolina Retirement System ("SCRS") and serves as a co-trustee of the Systems in conducting that review.

PEBA issues a Comprehensive Annual Financial Report ("CAFR") containing financial statements and required supplementary information for the Systems' Pension Trust Funds. The CAFR is publicly available through the Retirement Benefits' link on PEBA's website at www.peba.sc.gov, or a copy may be obtained by submitting a request to PEBA, PO Box 11960, Columbia, SC 29211-1960. PEBA is considered a division of the primary government of the state of South Carolina, and therefore, retirement trust fund financial information is also included in the comprehensive annual financial report of the State.

Plan Description - Substantially all Authority regular employees must participate in one of the components of the SCRS, a cost sharing, multiple-employer public employee retirement system, which was established by Section 9-1-20 of the South Carolina Code of Laws.

Benefit Provided - Vested employees ("Class Two Members") who retire at age 65 or with 28 years of service at any age are entitled to a retirement benefit, payable monthly for life. Vested employees (Class Three Members) who retire at age 65 or meet the "rule of 90 requirements" (i.e., the total of the member's age and the member's creditable service equals at least 90 years), are entitled to a retirement benefit, payable monthly for life. The annual benefit amount is equal to 1.82 percent of their average final compensation times years of service. Benefits fully vest on reaching five years of service for Class Two Members and eight years for Class Three Members. Reduced retirement benefits are payable as early as age 60 with vested service or 55 with 25 years of service for Class Two Members. The SCRS also provides death and disability benefits. Benefits are established by State statute.

Effective January 1, 2001, Section 9-1-2210 of the South Carolina Code of Laws allowed SCRS employees eligible for service retirement to participate in the Teacher and Employee Retention Incentive ("TERI") Program. TERI participants may retire and begin accumulating retirement benefits on a deferred basis without terminating employment for up to five years. Upon termination of employment or at the end of the TERI period, whichever is earlier, participants will begin receiving monthly service retirement benefits which include any cost of living adjustments granted during the TERI period. Because participants are considered retired during the TERI period, they do not earn service credit or disability retirement benefits. Effective July 1, 2005, TERI employees began "re-contributing" to the SCRS at the prevailing rate. However, no service credit is earned under the new regulations. The group life insurance of one times annual salary was re-established for TERI participants.

Effective July 1, 2012, the TERI program will close for Class Two members (members with effective date prior to July 1, 2012) on June 30, 2018, and it is not available to Class Three members (members with effective date on or after July 1, 2012). TERI was phased out in a 5-4-3-2-1 format. The TERI program ended on June 30, 2018, regardless of when a member entered the program.

Article X, Section 16 of the South Carolina Constitution requires that all State-operated retirement plans be funded on a sound actuarial basis. Title 9 of the South Carolina Code of Laws (as amended) prescribes requirements relating to membership, benefits and employee/employer contributions.

Effective July 1, 2002, new employees have a choice of the type of retirement plan in which to enroll. The State Optional Retirement Plan ("State ORP") which is a defined contribution plan is an alternative to the SCRS retirement plan which is a defined benefit plan. The contribution amounts are the same, (9.00 percent employee cost and 14.41 percent employer cost); however, under the State ORP, 5.00 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 9.41 percent is contributed to the SCRS. As of December 31, 2017, the Authority had 73 employees participating in the State ORP and consequently the related payments are not material.

Effective July 1, 2017, the Retirement System Funding and Administration Act of 2017 (the "Act") increased employer retirement contribution rates by 2 percent to 13.56 percent for SCRS. The employer contribution rate for the State ORP was increased to 13.56 percent, with 5 percent of the employer contribution being remitted directly to the participant's State ORP investment provider. The employer rate will continue to increase annually by 1 percent through July 1, 2022, with the ultimate employer rate reaching 18.56 percent. Employee rates for SCRS and the State ORP increased to and are capped at 9 percent. Employer and employee contribution rates may be decreased in equal amounts once the system is 85 percent funded. The employee contribution rate may not be less than ½ of the normal cost for the system. The Act also reduced the funding period for unfunded liabilities from 30 to 20 years over the next 10 years as well as lowered the current assumed annual rate of return from 7.5 percent to 7.25 percent. The assumed annual rate of return will expire July 1, 2021 and every four years thereafter. PEBA must propose an annual rate of return every four years, which will become effective if the General Assembly fails to enact a rate of return.

Contributions - All employees are required by State statute to contribute to the SCRS at the prevailing rate, currently 9.00 percent. The Authority contributed 14.41 percent of the total payroll for SCRS retirement. For 2018, the Authority also contributed an additional 0.15 percent of total payroll for group life. The contribution requirements for the prior four years were as follows:

Years Ended December 31,	**2018**	2017	2016	2015
		(Millions)		
From the Authority	**$ 19.80**	$ 17.70	$ 15.60	$ 14.80
From employees	**12.8**	12.6	11.8	11
Authority's covered payroll	**142.3**	142.7	140.1	136.4
Authority's contributions as a percentage of covered payroll	**13.9%**	12.4%	11.1%	10.9%

The Authority made 100 percent of the required contributions for each of the four years.

Liabilities, Expense and Deferred Outflows (Inflows) of Resources Related to Pensions - At December 31, 2018, the Authority reported a liability of $338.1 million. This includes its share of the net pension liability from SCRS as well as pension liabilities associated with the supplemental executive retirement plans ("SERP") noted under post-employment benefits, which were immaterial. The SCRS net pension liability was measured as of June 30, 2018 and determined by an actuarial valuation as of July 1, 2017. The Authority's proportionate share of the total net pension liability was based on the ratio of our actual contributions of $18.6 million paid to SCRS for the year ended June 30, 2018 relative to the actual contributions of $1.3 billion from all participating employers. The schedule of the Authority's proportionate share of the net pension liability for the years ended June 30, 2018 and 2017 are as follows:

	June 30, 2018	June 30, 2017
Authority's proportion of the net pension liability (%)	**1.43%**	1.43%
Authority's proportion of the net pension liability (millions)	**$ 321.8**	$ 323.1
Authority's covered employee payroll (millions)	**$ 142.3**	$ 142.7
Authority's proportion of the net pension liability as a percentage of its covered employee payroll	**226%**	226%
Plan fiduciary net position as a percentage of the total pension liability	**54.10%**	53.30%

For the year ended December 31, 2018, the Authority recognized a pension expense of $30.6 million, our proportionate share of the total pension expense. At December 31, 2018, the Authority reported deferred outflows (inflows) of resources related to pensions from the following sources:

	Deferred Outflows of Resources	**Deferred Inflows of Resources**
	(Thousands)	
Differences between expected and actual experience	**$ 637**	**$ 1,882**
Changes of assumptions	**12,816**	**0**
Net difference between projected and actual earnings on pension plan investments	**15,957**	**10,837**
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	**513**	**1,638**
Authority's contributions subsequent to the measurement date	**8,733**	**0**
Total	**$ 38,656**	**$ 14,357**

The Authority reported $8.7 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2019. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years. The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2018. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2017, was 4.080 years for SCRS.

Year Ending December 31:	
	(Thousands)
2019	**$ 12,192**
2020	**7,481**
2021	**(3,591)**
2022	**(516)**
Total	**$ 15,566**

For the year ended December 31, 2017, the Authority recognized a pension expense of $32.0 million, our proportionate share of the total pension expense. At December 31, 2017, the Authority reported deferred outflows (inflows) of resources related to pensions from the following sources:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ 1,448	$ 178
Changes of assumptions	18,978	0
Net difference between projected and actual earnings on pension plan investments	9,034	0
Changes in proportion and differences between Authority's contributions and proportionate share of plan contributions	719	2,639
Authority's contributions subsequent to the measurement date	8,318	0
Total	$ 38,497	$ 2,817

The Authority reported $8.3 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2018. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years. The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2017. Average remaining service lives of all employees provided with pensions through the pension plans at July 1, 2016, measurement date was 4.073 years for SCRS.

Year Ending December 31:	
	(Thousands)
2018	$ 8,100
2019	13,250
2020	8,542
2021	(2,529)
Total	$ 27,363

Actuarial Assumptions - Actuarial valuations of the Authority involve estimates of the reported amount and assumptions about probability of occurrence of events far into the future. Examples include assumptions about future employment mortality and future salary increases. Amounts determined regarding the net pension liability are subject to continual revision as actual results are compared with past expectations and new estimates are made about the future.

Significant actuarial assumptions and other inputs used to measure the total pension liability as of December 31, 2018:

- **Measurement Date**	**June 30, 2018**
- **Valuation Date**	**July 1, 2017**
- **Expected Return on Investments**	**7.25%**
- **Inflation**	**2.25%**
- **Future Salary Increases**	**3.00% to 12.50% (varies by service)**
- **Mortality Assumption**	**2016 Mortality Table set back projected at SCALE AA from year 2016 Males multiplied by 100%. Females multiplied by 111%.**

Significant actuarial assumptions and other inputs used to measure the total pension liability as of December 31, 2017:

- Measurement Date	June 30, 2017
- Valuation Date	July 1, 2016
- Expected Return on Investments	7.25%
- Inflation	2.25%
- Future Salary Increases	3.00% to 12.50% (varies by service)
- Mortality Assumption	RP 2000 Mortality Table set back projected at SCALE AA from year 2000. RP-2000 Males multiplied by 100%. RP-2000 Females multiplied by 111%.

Discount Rate - The discount rate used to measure the total pension liability was 7.25 percent. The projection of cash flows used to determine the discount rate assumed that contributions from participating employers in SCRS will be made based on the actuarially determined rates based on provisions in the South Carolina State Code of Laws. Based on those assumptions, the fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods of projected benefit payments to determine the total pension liability.

Long-term Expected Rate of Return - For the measurement date as of June 30, 2018, the long-term expected rate of return on pension plan investments is based upon 30 year capital market assumptions. The long-term expected rates of return represent assumptions developed using an arithmetic building block approach primarily based on consensus expectations and market based inputs. Expected returns are net of investment fees. The expected returns, along with the expected inflation rate, form the basis for the target allocation adopted at the beginning of the 2018 fiscal year. The long-term expected rate of return is produced by weighting the expected future real rates of return by the target allocation percentage and adding expected inflation and is summarized in the table on the following page. For actuarial purposes, the 7.25 percent assumed annual investment rate of return (as prescribed by SC Code Section 9-16-335) used in the calculation of the total pension liability includes a 5.00 percent real rate of return and a 2.25 percent inflation component.

Asset Class	Target Asset Allocation	Expected Arithmetic Real Rate of Return	Long Term Expected Portfolio Real Rate of Return
Global Equity			
Global Public Equity	33.00%	6.99%	2.31%
Private Equity	9.00%	8.73%	0.79%
Equity Options Strategies	5.00%	5.52%	0.28%
Real Assets			
Real Estate (Private)	6.00%	3.54%	0.21%
Real Estate (REITs)	2.00%	5.46%	0.11%
Infrastructure	2.00%	5.09%	0.10%
Opportunistic			
GTAA/Risk Parity	8.00%	3.75%	0.30%
Hedge Funds (non-PA)	2.00%	3.45%	0.07%
Other Opportunistic Strategies	3.00%	3.75%	0.11%
Diversified Credit			
Mixed Credit	6.00%	3.05%	0.18%
Emerging Markets Debt	5.00%	3.94%	0.20%
Private Debt	7.00%	3.89%	0.27%
Conservative Fixed Income			
Core Fixed Income	10.00%	0.94%	0.09%
Cash and Short Duration (Net)	2.00%	0.34%	0.01%
Total Expected Real Return	100.0%		5.03%
Inflation for Actuarial Purposes			2.25%
Total Expected Nominal Return			7.28%

For the measurement date as of June 30, 2017, the long-term expected rate of return on pension plan investments for actuarial purposes is based upon the 30-year capital market assumptions. The actuarial long-term expected rates of return represent best estimates of arithmetic real rates of return for each major asset class and were developed in coordination with the investment consultant for the Retirement System Investment Commission ("RSIC") using a building block approach, reflecting observable inflation and interest rate information available in the fixed income markets as well as Consensus Economic forecasts. The actuarial long-term assumptions for other asset classes are based on historical results, current market characteristics, and professional judgment.

The RSIC has exclusive authority to invest and manage the retirement trust funds' assets. As co-fiduciary of the Systems, statutory provisions and governance policies allow the RSIC to operate in a manner consistent with a long-term investment time horizon. The expected real rates of investment return, along with the expected inflation rate, form the basis for the target asset allocation adopted annually by the RSIC. For actuarial purposes, the long-term expected rate of return is calculated by weighting the expected future real rates of return by the target allocation percentage and then adding the actuarial expected inflation which is summarized in the table below. For actuarial purposes, the 7.25 percent assumed annual investment rate of return (as prescribed by SC Code Section 9-16-335) used in the calculation of the total pension liability includes a 5.00 percent real rate of return and a 2.25 percent inflation component.

Asset Class	Target Asset Allocation	Expected Arithmetic Real Rate of Return	Long Term Expected Portfolio Real Rate of Return
Global Equity			
Global Public Equity	31.00%	6.70%	2.08%
Private Equity	9.00%	9.60%	0.86%
Equity Options Strategies	5.00%	5.90%	0.30%
Real Assets			
Real Estate (Private)	5.00%	4.30%	0.22%
Real Estate (REITs)	2.00%	6.30%	0.13%
Infrastructure	1.00%	6.30%	0.06%
Opportunistic			
GTAA/Risk Parity	10.00%	4.20%	0.42%
Hedge Funds (non-PA)	4.00%	3.80%	0.15%
Other Opportunistic Strategies	3.00%	4.20%	0.12%
Diversified Credit			
Mixed Credit	6.00%	3.90%	0.24%
Emerging Markets Debt	5.00%	5.00%	0.25%
Private Debt	7.00%	4.40%	0.31%
Conservative Fixed Income			
Core Fixed Income	10.00%	1.60%	0.16%
Cash and Short Duration (Net)	2.00%	0.90%	0.02%
Total Expected Real Return	100.00%		5.32%
Inflation for Actuarial Purposes			2.25%
Total Expected Nominal Return			7.57%

Sensitivity Analysis - For the measurement date as of June 30, 2018, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.25% as well as SERP discount rates of 3.50% for both the pre-2007 and non-qualified benefits for what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current rate.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(Thousands)	
Authority's proportionate share of the net pension liability	**$ 428,674**	**$ 338,128**	**$ 273,097**

For the measurement date as of June 30, 2017, the following table presents the Authority's collective net pension liability calculated using the Authority's discount rate of 7.25% as well as SERP discounts rates of 3.00% for both the pre-2007 and 3.50% for the non-qualified benefits for what the Authority's net pension liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current rate.

	1.00% Decrease	**Current Discount Rate**	**1.00% Increase**
		(Thousands)	
Authority's proportionate share of the net pension liability	$ 433,243	$ 338,783	$ 281,029

Other Retirement Benefits - The Authority also provides retirement benefits to certain employees designated by management and the Board under SERP. Benefits are established and may be amended by management and the Authority's Board and include retirement benefit payments for a specified number of years and death benefits. The cost of these benefits is actuarially determined annually. Beginning in 2006, these plans were segregated into internal and external funds. The qualified benefits are funded externally with the annual cost set aside in a trust administered by a third party. The pre-2007 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. Effective February 23, 2018, entry into the plan is closed and no employee shall become a participant on or after this date. At December 31, 2018, the Authority reported an asset of $2.6 million and a liability of $16.3 million associated with the three plans as well as deferred outflows and inflows as follows:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	**$ 1,910**	**$ 1,650**
Changes of assumptions	**315**	**274**
Net difference between projected and actual earnings on pension plan investments	**882**	**458**
Authority's contributions subsequent to the measurement date	**96**	**0**
Total	**$ 3,203**	**$ 2,382**

The Authority reported $96,000 as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net pension liability in the year ending December 31, 2019. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years.

The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2018.

Year Ending November 30:	
	(Thousands)
2019	$ 556
2020	(10)
2021	199
2022	(21)
2023	0
Total	$ 724

At December 31, 2017, the Authority reported an asset of $2.5 million and a liability of $15.6 million associated with the three plans as well as deferred outflows and inflows as follows:

	Deferred Outflows of Resources	Deferred Inflows of Resources
	(Thousands)	
Differences between expected and actual experience	$ 1,743	$ 1,370
Changes of assumptions	424	19
Net difference between projected and actual earnings on pension plan investments	422	611
Authority's contributions subsequent to the measurement date	95	0
Total	$ 2,684	$ 2,000

The Authority reported $95,000 as deferred outflows of resources related to contributions subsequent to the measurement date which was recognized as a reduction of the net pension liability in the year ending December 31, 2018. Other amounts reported as deferred outflows (inflows) of resources will be recognized in pension expense in future years.

The following schedule reflects the amortization of the Authority's proportional share of the net balance of remaining deferred outflows (inflows) of resources at December 31, 2017.

Year Ending November 30:	(Thousands)
2018	$ 215
2019	215
2020	(61)
2021	220
2022	0
Total	$ 589

Summer Nuclear Unit 1 Retirement - The Authority and SCE&G are parties to a joint ownership agreement for Summer Nuclear Unit 1 at the Summer Nuclear Station. As such, the Authority is responsible for funding its share of pension requirements for the nuclear station personnel. Any earnings generated from the established pension plan are shared proportionately and used to reduce the allocated funding.

As of December 31, 2018 and 2017, the Authority had a noncurrent pension liability of $5.7 million and $5.0 million, respectively.

In accordance with FASB ASC 715, the Authority has a regulatory liability balance of approximately $19.3 million and $16.4 million for the unfunded portion of pension benefits at December 31, 2018 and 2017, respectively. Additional information may be obtained by reference to the SCANA Corporation Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2018.

Note 12 – Other Postemployment Benefits (OPEB)

Vacation / Sick Leave - Full-time employees earn 10 days of vacation leave for service under five years and 15 days of vacation leave for service under 11 years. Employees earn an additional day of vacation leave for each year of service over 10 until they reach the maximum of 25 days per year. Employees earn two hours per pay period, plus 20 additional hours at year-end for sick leave.

Employees may accumulate up to 45 days of vacation leave and 180 days of sick leave. Upon termination, the Authority pays employees for unused vacation leave at the pay rate then in effect. In addition, the Authority pays employees upon retirement 20 percent of their sick leave at the pay rate then in effect.

Plan Description - The Authority participates in an agent multiple-employer defined benefit healthcare plan whereby PEBA Insurance Benefits provides certain health, dental and life insurance benefits for eligible retired employees of the Authority. The retirement insurance benefits available are defined by PEBA Insurance Benefits and substantially all of the Authority's employees may become eligible for these benefits if they meet retirement eligibility with a minimum of 10 years of earned service or upon reaching age 60 after leaving employment with at least 20 years of service. Currently, approximately 1069 retirees meet these requirements.

For employees hired May 2, 2008 or thereafter, the number of years of earned service necessary to qualify for funded retiree insurance is 15 years for a one-half contribution, and 25 years for a full contribution. PEBA Insurance Benefits may be contacted at: PO Box 11661, Columbia, S.C. 29211-1661 and PEBA Retirement Benefits may be contacted at PO Box 11660, Columbia, S.C. 29211-1960.

As of the measurement date, June 30, 2018, the following employees were covered by the benefit terms:

Inactive Plan Members or Beneficiaries Currently Receiving Benefits	960
Inactive Plan Members Entitled to But Not Yet Receiving Benefits	-
Active Plan Members	1,698
Total Plan Members	**2,658**

Funding Policy - Prior to 2010, the Authority used the unfunded pay-as-you-go option (or cash disbursement) method pursuant to GASB 45 to record the net OPEB obligations. During 2010, the Authority elected to adopt an advanced or pre-funding policy and established an irrevocable trust with Synovus Trust Company. In 2018 with the implementation of GASB 75, the Authority established a formal funding plan and elected to fund the OPEB obligation over a 30-year closed period. This method of funding will result in a lower OPEB liability, more favorable discount rates, and establishes a method for writing off the regulatory asset as funding occurs.

Net OPEB Liability - The components of the net OPEB liability at June 30, 2018 were as follows:

	(Thousands)
Total OPEB Liability	$ 232,702
Plan fiduciary net position	59,928
Authority's net OPEB liability	$ 172,774
Plan fiduciary net position as a percentage of the total OPEB liability	25.75%

Actuarial Methods and Assumptions - The total OPEB liability was determined by an actuarial valuation as of December 31, 2016 using the following actuarial assumptions, applied to all periods included in the measurement, unless otherwise specified.

Actuarial Methods and Assumptions	
Actuarial Cost Method	Individual Entry-Age
Amortization Method	Level dollar
Amortization Period	Closed period; 29 years remaining as of the beginning of FYE18
Asset Valuation	Market Value
Investment Rate of Return	4.50%, net of investment expenses, including inflation
Inflation	2.25%
Salary Increases	3.00% to 7.00%, including inflation
Demographic Assumptions	Based on the experience study covering the five year period ending June 30, 2015 as conducted for the South Carolina Retirement Systems (SCRS)
Mortality	For healthy retirees, the 2016 Public Retirees of South Carolina Mortality Table for Males and the 2016 Public Retirees of South Carolina Mortality Table for Females are used with fully generational mortality projections based on Scale AA from the year 2016. The following multipliers are applied to the base tables: 100% for male SCRS members, 111% for female SCRS members.
Participation Rates	Rates of 90% for fully funded retirees, 60% for partially funded retirees, and 20% for retirees not eligible for any explicit subsidy
Healthcare Cost Trend Rates	Initial rate of 6.75% declining to an ultimate rate of 4.15% after 14 years; Ultimate trend rate includes a 0.15% adjustment for the excise tax

Investments - The investments of the Authority must follow the general guidelines set by the Enabling Legislation. The Authority is required to invest without limitation its revenues in obligations the interest and principal of which are guaranteed or are fully secured by contracts with the United States of America; in obligations of any agency, instrumentality or corporation which has been or may hereafter be created by or pursuant to an act of Congress; direct and general Obligations of the State of South Carolina; and certificates of deposit issued by any bank, trust company or national banking association which do business in South Carolina.

Asset Class	Target Allocation	Long-Term Expected Real Rate of Return
Cash	6.8%	0.1%
Fixed Income	93.2%	2.6%
Total Blended Average	**100.0%**	**2.5%**

Asset Allocation at June 30, 2018

The rate of return for 2018 on the Trust was (0.34%).

Discount rate. A Single Discount Rate of 4.50% was used to measure the total OPEB liability. The asset portfolio of the OPEB trust can support a 4.50% long term rate of return. Santee Cooper's funding policy utilizes a closed amortization period. As a result, the plan's fiduciary net position is projected to be sufficient to pay benefits.

Schedule of Changes in Net OPEB Liability
Fiscal Year Ended December 31, 2018

	Total OPEB Liability	Plan Fiduciary Net Position	Net OPEB Liability
		(Thousands)	
Beginning balance	$ 224,768	$ 52,950	$ 171,818
Service cost	5,405		5,405
Interest on the total OPEB liability	10,073		10,073
Changes of benefit terms	0		0
Difference between expected and actual experience	(291)		(291)
Changes of assumptions	0		0
Employer contributions		14,455	(14,455)
Net investment income		(120)	120
Benefit payments	(7,253)	(7,253)	0
Administrative expense		(104)	104
Other		0	0
Net changes	7,934	6,978	956
Ending balance	$ 232,702	$ 59,928	$ 172,774

Ending balances are as of the measurement date, June 30, 2018.

Sensitivity of the net OPEB liability to changes in the discount rate - The following presents the net OPEB liability of the Authority calculated using the Authority's discount rate of 4.50% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate.

	1.00% Decrease	Current Discount Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 208,138	$ 172,774	$ 143,979

Sensitivity of the net OPEB liability to changes in the healthcare cost trend rates - The following presents the net OPEB liability of the Authority calculated using the Authority's healthcare cost trend rate of 7.00% and for what the Authority's net OPEB liability would be if it were calculated using a discount rate that is 1.00% lower or 1.00% higher than the current discount rate.

	1.00% Decrease	Healthcare Cost Trend Rate	1.00% Increase
		(Thousands)	
Net OPEB liability	$ 138,515	$ 172,774	$ 216,162

OPEB Expense and Deferred Outflows (Inflows) of Resources Related to OPEB - For the year ended December 31, 2018; the Authority recognized OPEB expense of $13.5 million. At December 31, 2018, the Authority reported deferred outflows (inflows) of resources related to OPEB from the following sources:

	Deferred Outflows of Resources		Deferred Inflows of Resources	
		(Thousands)		
Differences between expected and actual experience	**$**	**0**	**$**	**249**
Changes of assumptions		**0**		**0**
Net difference between projected and actual earnings on OPEB plan investments		**2,130**		**0**
Authority's contributions subsequent to the measurement date		**21,046**		**0**
Total	**$**	**23,176**	**$**	**249**

The Authority reported $21 million as deferred outflows of resources related to contributions subsequent to the measurement date which will be recognized as a reduction of the net OPEB liability in the year ending December 31, 2019. Other amounts reported as deferred outflows (inflows) of resources will be recognized in OPEB expense in future years.

The following schedule reflects the amortization of the Authority's balance of remaining deferred outflows (inflows) of resources at December 31, 2018.

Year Ending December 31:		
		(Thousands)
2019	$	491
2020		491
2021		491
2022		491
2023		(42)
Thereafter,		(41)
Total	$	1,881

Schedule of Changes in Net OPEB Liability and Related Ratios
Fiscal Year Ended December 31, 2018

Measurement period ending June 30		**2018**
		(Thousands)
Service Cost	$	5,405
Interest on the total OPEB liability		10,073
Difference between expected and actual experience		(291)
Benefit payments		(7,253)
Net change in total OPEB liability		7,934
Total OPEB liability - beginning		224,768
Total OPEB liability - ending (a)	$	232,702
Plan fiduciary net position		
Employer contributions	$	14,455
OPEB plan net investment income		(120)
Benefit payments		(7,253)
OPEB plan administrative expense		(104)
Net change in plan fiduciary net position		6,978
Plan fiduciary net position - beginning		52,950
Plan fiduciary net position - ending (b)	$	59,928
Net OPEB liability - ending (a) - (b)	$	172,774
Plan fiduciary net position as a percentage of total OPEB liability		25.75 %
Covered-employee payroll	$	156,059,022
Net OPEB liability as a percentage of covered-employee payroll		110.71 %

Schedule of Contributions
(Thousands)

FY Ending December 31,	Actuarially Determined Contribution	Actual Contribution	Contribution Deficiency (Excess)	Covered Payroll	Actual Contribution as a % of Covered Payroll
2018	$ 15,364	$ 14,455	$909	$ 156,059	9.26%

Summer Nuclear OPEB - The Authority is responsible for funding its share of OPEB costs for nuclear station employees. The Authority's liability balances as of December 31, 2018 and 2017 were both approximately $11.7 million and $11.4 million, respectively.

In accordance with FASB ASC 715, the Authority recorded a regulatory liability of approximately $1.0 million and $3.3 million for the unfunded portion of OPEB costs at December 31, 2018 and 2017, respectively. Additional information may be obtained by reference to the SCANA Corporation Annual Report on Form 10K as filed with the Securities Exchange Commission as of December 31, 2018.

Note 13 – Credit Risk and Major Customers

In 2018, the Authority had one customer that accounted for more than 10 percent of the Authority's sales:

Customer:		2018		2017
		(Millions)		
Central	**$**	**1,034**	$	1,026

The Authority maintains an allowance for uncollectible accounts based upon the expected collectability of all accounts receivable. The allowance at each year ended December 31, 2018 and 2017 was $2.1 million and $2.2 million, respectively.

Note 14 – Storm Damage

2018
In September 2018, the Authority's system sustained damages from Hurricane Florence. As a result, portions of South Carolina were declared federal disasters areas for damages, and the entire state was declared eligible for protective measures expense relief. During 2018, the Authority incurred $11.7 million in capital and maintenance costs. A receivable of $8.8 million was recorded as of December 31, 2018, in anticipation for federal reimbursement in 2019. No additional costs for the event are anticipated in 2019.

The Authority does not expect to increase rates due to the impacts of these events and foresees no measurable long-term impacts on its operation or the demand for electricity by its customers.

2017
In addition to the $11.4 million costs for Hurricane Matthew accrued in 2016, the Authority incurred $5.5 million in capital and maintenance costs during 2017.

In September 2017, the Authority's system sustained damages from Hurricane Irma. As a result, portions of South Carolina were declared federal disaster areas for damages, and the entire state was declared eligible for protective measure expense relief. During 2017, the Authority incurred $1.4 million in capital and maintenance costs.

Note 15 – Change in Accounting Principle

The Authority implemented GASB statement 75, Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions, in the year ended December 31, 2018. The implementation of the statement required the Authority to record a prior year beginning balance for the net OPEB liability and contributions made by the Authority during the measurement period (year ended December 31, 2017). On October 13, 2017 the Board approved the use of regulatory accounting to offset the initial net OPEB liability. As a result, the Authority recorded a regulatory asset of $165.2 million. During 2018, $12.0 million was amortized to coincide with a deposit to the trust of the same amount. The remaining balance outstanding at December 31, 2018 was $153.2 million.

Note 16 – Subsequent Events

SCANA and Dominion Merger. On January 2, 2019 Dominion Energy, Inc. and SCANA Corporation announced that they completed their proposed merger. SCANA Corporation will be a first-tier, wholly owned subsidiary of Dominion Energy. Its operating companies – including South Carolina Electric & Gas Company (SCE&G), Public Service Company of North Carolina, Incorporated (PSNC Energy), and SCANA Energy Marketing, Inc. (SEMI) – and its services company will be managed by a new operating segment, the Southeast Energy Group.

Summer Nuclear 2 and 3 Combined Construction and Operating Licenses. On January 28, 2019, the Santee Cooper Board approved a resolution authorizing the Interim President and CEO to consent to SCE&G's request to terminate the Summer Nuclear Units 2 & 3 COLs. That consent was conveyed to the Nuclear Regulatory Commission in a letter dated January 29, 2019.

Commitments and Contingencies. In February 2019, the Authority entered into a contract with Meridian WGS, LLC ("Meridian") to convert low quality gypsum slurry stored at WGS into drywall quality gypsum using a proprietary process. The Authority has also entered into a lease agreement with Meridian that will allow it to construct its facility at WGS. Pending Meridian obtaining financing for construction, it will permit, construct and operate the conversion facility at WGS to produce drywall quality gypsum that can be used to meet contracted obligations. The conversion process allows waste material to be converted and beneficially used as drywall quality gypsum while providing an environmentally responsible and low cost option to close the slurry pond.

Legislative Matters. On February 1, 2019, ICF issued its report to the Evaluation Committee. The Evaluation Committee is now expected to continue its review of Santee Cooper which includes, among other things, the consideration of various alternatives for Santee Cooper such as managing or restructuring Santee Cooper or selling portions of its assets.

On January 29th, 2019, Chairman Charlie Condon was re-nominated by the Governor to serve as Board Chair. He will serve as Interim Chairman until either the appointment is approved or until the end of the regular 2019 legislative session, whichever occurs first.

On February 21, 2019, the South Carolina Senate announced the creation of the Select Committee on Santee Cooper. The Senate has not yet set a date for the first meeting of the Select Committee.

The General Assembly is scheduled to meet from January 8, 2019 to May 9, 2019. Legislation may be introduced that impacts Santee Cooper's operations. Santee Cooper will be educating and informing the General Assembly of the impact of any relevant legislation that may impact its customers and operations.

Legal Matters. ***Timothy Glibowski et al. v. SCANA, SCE&G, Santee Cooper, Kevin Marsh, Jimmy Addison, Stephen Byrne, Martin Phalen, Mark Cannon, Russell Harris, Ronald Lindsay, James Micali, and Lonnie Carter*** (case no. 9:18-cv-273-TLW in the U.S. Dist. Court, Dist. of S.C., Beaufort Division): Plaintiffs filed this putative class action in connection with the decision to abandon construction of Summer Nuclear Units 2 and 3. The Second Amended Complaint was filed on January 28, 2019. It includes two proposed classes: (1) SCANA customers and (2) Santee Cooper customers who were charged and paid advance charges for costs associated with the construction of the units from 2007 to the present.

On February 22, 2019, the South Carolina Supreme Court issued its order denying Santee Cooper's petition for appellate case no. 2018-001172.

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REQUIRED SUPPLEMENTAL FINANCIAL DATA:

Santee Cooper's Proportionate Share of the Net Pension Liability
Required Supplementary Information
Last Five Fiscal Years

Years Ended in June 30,	2018	2017	2016	2015	2014
Authority's proportion of the net pension liability (%)	1.43%	1.43%	1.45%	1.44%	1.45%
Authority's proportion of the net pension liability (millions)	$ 321.8	$ 323.1	$ 309.7	$ 273.6	$ 249.7
Authority's covered employee payroll (millions)	$142.30	$142.70	$140.10	$136.40	$131.50
Authority's proportion of the net pension liability as a percentage of its covered employee payroll	226%	226%	221%	201%	190%
Plan fiduciary net position as a percentage of the total pension liability	54.1%	53.3%	56.9%	59.9%	59.9%

Santee Cooper's Contributions
Required Supplementary Information
Last Five Fiscal Years

Years Ended December 31,	2018	2017	2016	2015	2014
			(Millions)		
Required Contributions:					
From the Authority	$ 19.80	$ 17.70	$ 15.60	$ 14.80	$ 13.90
From employees	12.8	12.6	11.8	11	10.2
Contributions in relation to the required contributions:					
From the Authority	$ 19.80	$ 17.70	$ 15.60	$ 14.80	$ 13.90
From employees	12.8	12.6	11.8	11	10.2
Contribution deficiency (excess)	$ -	$ -	$ -	$ -	$ -
Authority's covered payroll	142.3	142.7	140.1	136.4	131.5
Authority's contributions as a percentage of covered payroll	13.90%	12.40%	11.10%	10.90%	10.50%

Schedule of Total Pension
Liability as a Percentage of Covered Payroll
Required Supplementary Information
Last Five Fiscal Years

Years Ended June 30,	2018	2017	2016	2015	2014
Authority's proportion of the net pension liability (millions)	$ 321.8	$ 323.1	$ 309.7	$ 273.6	$ 249.7
Authority's covered employee payroll (millions)	$ 142.3	$ 142.7	$ 140.1	$ 136.4	$ 131.5
Authority's proportion of the net pension liability as a percentage of its covered employee payroll	226%	226%	221%	201%	190%

Santee Cooper's Schedule of Changes in the Total OPEB Liability and Related Ratios
Required Supplementary Information
Fiscal Year Ended December 31, 2018

Measurement period ending June 30		**2018**
Total OPEB Liability		
Service Cost	$	5,404,788
Interest on the total OPEB liability		10,072,981
Difference between expected and actual experience		(291,156)
Benefit payments		(7,253,210)
Net change in total OPEB liability		7,933,403
Total OPEB liability - beginning		224,768,231
Total OPEB liability - ending (a)	$	232,701,634
Plan fiduciary net position		
Employer contributions	$	14,454,566
OPEB plan net investment income		(119,535)
Benefit payments		(7,253,210)
OPEB plan administrative expense		(103,803)
Net change in plan fiduciary net position		6,978,018
Plan fiduciary net position - beginning		52,950,142
Plan fiduciary net position - ending (b)	$	59,928,160
Net OPEB liability - ending (a) - (b)	$	172,773,474
Plan fiduciary net position as a percentage of total OPEB liability		25.75 %
Covered-employee payroll	$	156,059,022
Net OPEB liability as a percentage of covered-employee payroll		110.71 %

Notes to Schedule:
Changes of assumptions: Changes of assumptions and other inputs reflect the effects of changes in the discount rate of each period. The following is the discount rate used in this period:

Fiscal Year	Rate
2018	4.50%

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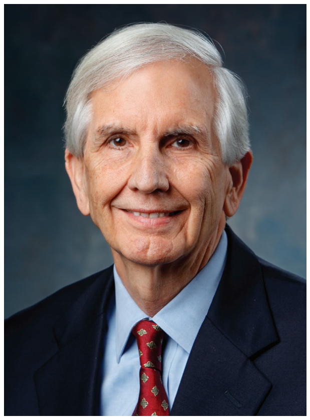
Board of Directors



Charlie M. Condon
Interim Chairman
At-Large
Sullivan's Island, S.C..

Chairman Condon is an attorney and the owner of Charlie Condon Law Firm LLC in Mount Pleasant, S.C.

Dan J. Ray
1st Vice Chairman
Georgetown County
Georgetown, S.C.

Director Ray is president of DR Capital Group, a Pawleys Island-based financial advisory and investment company.

David F. Singleton
2nd Vice Chairman
Horry County
Myrtle Beach, S.C.

Director Singleton is president of Singleton Properties, a real estate investment and sales firm.

Kristofer D. Clark
3rd Congressional District
Easley, S.C.

Director Clark is a broker with Easlan Capital and owner of Pristine Properties LLC.

William A. Finn
1st Congressional District
Mount Pleasant, S.C.

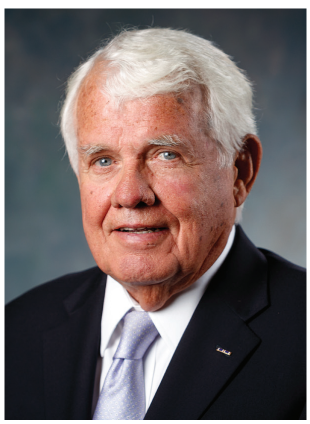
Director Finn is chairman of AstenJohnson Inc., a specialty textile company for the printing and papermaking industries based in Charleston.

Merrell W. Floyd
7th Congressional District
Conway, S.C.

Director Floyd is a retired staff coordinator for Horry Electric Cooperative.

J. Calhoun Land IV
6th Congressional District
Manning, S.C.

Director Land is a partner in Land, Parker & Welch, a general practice firm in Manning.

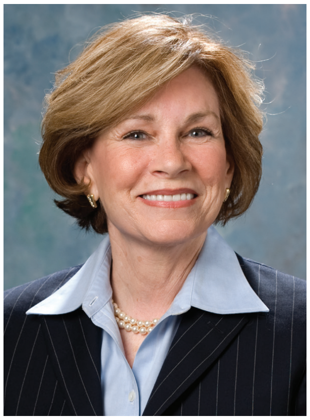


Charles H. "Herb" Leaird
5th Congressional District
Sumter, S.C.

Director Leaird is the former CEO of Black River Electric Cooperative and also served as CEO of Lynches River Electric Cooperative.

Stephen H. Mudge
At-Large
Clemson, S.C.

Director Mudge is the cofounder, president and CEO of Serrus Capital Partners Inc., a Greenville, S.C.-based real estate investment firm.



Peggy H. Pinnell
Berkeley County
Moncks Corner, S.C.

Director Pinnell is the owner of the Peggy H. Pinnell Insurance Agency in Moncks Corner, a State Farm agency.

Barry D. Wynn
4th Congressional District
Spartanburg, S.C.

Director Wynn is president of Colonial Trust Company, a private trust company specializing in investment management and estate services.

Notes:

The State Senate approved on June 28, 2018, the nomination of Charles H. "Herb" Leaird to a seven-year term on the Santee Cooper Board of Directors, a term that began in 2016 and will expire May 19, 2023.

On July 23, 2018, Chairman Charlie Condon was appointed as Interim Chairman. The term of the Board Chair expires on May 19, 2025. However, Chairman Condon was appointed as an Interim Appointment. Subsequently, on Jan. 29, 2019, he was renominated by the Governor to serve as Board Chair. He will serve as Interim Chairman until either the appointment is approved or until the end of the regular 2019 legislative session, whichever occurs first.

On Dec. 10, 2018, Director Dan J. Ray was elected to the role of 1st Vice Chairman and Director David F. Singleton was elected to the role of 2nd Vice Chairman.

Director Jack F. Wolfe Jr. resigned from the Board of Directors on June 27, 2018.

Advisory Board

Henry D. McMaster	Governor
Alan Wilson	Attorney General
Mark Hammond	Secretary of State
Richard Eckstrom	Comptroller General
Curtis M. Loftis Jr.	State Treasurer

Executive Leadership

James E. Brogdon Jr.	Interim President and Chief Executive Officer
Marc R. Tye	Executive Vice President and Chief Operating Officer
Jeffrey D. Armfield[1]	Senior Vice President and Chief Financial Officer
J. Michael Baxley Sr.	Senior Vice President and General Counsel
Michael R. Crosby	Senior Vice President, Nuclear Energy
Dominick G. Maddalone	Senior Vice President, Technology Services, and Chief Information Officer
Arnold R. Singleton	Senior Vice President, Power Delivery
Pamela J. Williams	Senior Vice President, Corporate Services

Management

Charles S. "Sam" Bennett	Vice President, Administration
Michael C. Brown	Vice President, Wholesale and Industrial Services
Victoria N. Budreau	Vice President, Fuels Strategy and Supply
Daniel D. Camp	Vice President, Real Estate
Thomas B. Curtis	Vice President, Generating Stations
Rahul Dembla	Vice President, Planning and Pricing
B. Shawan Gillians[2]	Treasurer
Jane H. Hood	Vice President, Environmental and Water Systems Management
Thomas L. Kierspe	Vice President, Transmission Operations
Richard S. Kizer	Vice President, Public Affairs
Kenneth W. Lott III[3]	Vice President, Human Resource Management
J. Michael Poston	Vice President, Retail Operations
Suzanne H. Ritter	Vice President and Controller
Elizabeth H. Warner	Vice President, Legal Services, and Corporate Secretary

Auditor

Monique L. Washington	General Auditor

1 – Jeffrey D. Armfield announced his retirement effective April 5, 2019.
2 – B. Shawan Gillians was named Treasurer on June 25, 2018.
3 – Kenneth W. Lott III was named Vice President, Human Resource Management on March 19, 2018.

Office Locations*

MONCKS CORNER OFFICE

Santee Cooper Headquarters
1 Riverwood Drive
Moncks Corner, SC 29461
843-761-8000
843-761-4122 (fax)

MYRTLE BEACH OFFICE

1703 Oak St.
Myrtle Beach, SC 29577
843-448-2411
843-626-1923 (fax)

*Santee Cooper announced on Jan. 22, 2018, that the utility would close three offices. The Garden City Beach Retail Office closed on April 27, 2018, the North Myrtle Beach Retail Office closed on June 1, 2018, and the Conway Retail Office closed on June 29, 2018.

1-1 Please provide a yearly breakdown of Santee Cooper's expenditures for the following items:
See file "20190625 ORS Request 1-1 Expenditures by Year.xls"

a. Total expenditures for V.C. Summer Units 2 and 3 (the "Units")
b. Expenditures related to Transmission – There is no Transmission related to VC Summer 2 & 3 only. All Transmission assets are being utilized by all other Santee Cooper generating facilities and system upgrades were planned prior to the Nuclear project. The Switchyard located at the VC Summer site is being utilized by VC Summer 1.
c. Expenditures Related to Nuclear Fuel Inventory –

1-2 Please provide any and all studies performed on behalf of Santee Cooper or related to Santee Cooper to determine the value of property used to provide electric service to retail customers ("rate base"). This may include, but is not limited to utility plant in service, accumulated depreciation, contributed capital/contributions in aid of construction ("CIAC"), cash working capital, materials and supplies, prepayments, construction work-in-progress ("CWIP"), regulatory assets, deferred outflows, regulatory liabilities, and deferred inflows.

a. Provide copies of all supporting documents and calculations used in the study or studies.
b. Identify the dollar value of rate base attributed to:
   i. Total expenditures for the Units
   ii. Transmission expenditures related to the Units
   iii. Nuclear Inventory expenditures related to the Units
c. Identify the total dollar value of the Units, including Transmission and Nuclear Inventory, funded by debt.
d. Identify the total dollar value of Owner's Costs for the Units, including Transmission and Nuclear Inventory.

Cooper uses a Cash Basis method, typical of public utilities, to develop our retail rates. Under this method there is not a "rate base", therefore no studies of "rate base" have been conducted as described above. As we discussed with the ORS representatives, Santee Cooper does conduct a depreciation study every 6-8 years and is currently in the process of conducting this study. If you would like, we can provide you with this study once it is completed. In addition, Santee Cooper also conducts or utilizes studies to determine its assets & liabilities, regulatory assets & liabilities, and deferred inflows & outflows related to nuclear decommissioning/retirement, ash ponds, SERP and OPEB. If those studies would be helpful we can provide you copies. In addition, we participate in the State's multi-employer pension plan and have various assets, liabilities, deferred inflows and deferred outflows related to that plan. The state of SC conducts this study and provides us with the information to record our share of such amounts. We can obtain copies of those studies from the PEBA website if you would like.

1-3 In response to this series of questions, the regulatory definition of "used and useful" is defined as: Per our phone conference with ORS on 7/10/19 @11:00 am, question 1-3 specifically relates to any items identified in question 1-2 related to VC Summer Units 2&3. No studies related to those Units were identified in 1-2 therefore the response to question 1-3 is "NA".

1-3

Assets to be physically used and useful to current ratepayers before those ratepayers can be asked to pay the costs associated with them.

a. Identify the total value of rate base attributed to "used and useful" assets transferred into utility plant in service or inventory from the Units including Transmission and Nuclear Inventory. "NA"

b. Identify and provide the dollar value for any assets Santee Cooper has transferred into utility plant in service or inventory, but do not fit the definition of "used and useful." Provide an explanation for why the assets are not considered "used and useful." "NA"

1-4 Please complete Attachment A of the attached Excel workbook. The amounts provided should be as of December 31, 2018.

See file: "20190625 - ORS Request Attachments A-E 7-19-19.xls"

Per our phone conference with ORS on 7/10/19@ 11:00am, Santee Cooper was given clarifying direction requesting only electric system only.

a. Identify the dollar value funded by debt attributed to the Units, including Transmission and Nuclear Inventory. All of VCS 2/3 was funded entirely by debt.

b. Provide Santee Cooper's debt to equity ratio as of December 31, 2018. Santee Cooper's electric only debt to equity is 75/25.

c. Identify the dollar value of the Owner's Costs attributed to the Units, including Transmission and Nuclear Inventory. – Santee Cooper did not segregate out project cost between EPC and Owners Cost.

d. Identify the dollar value of all assets associated with the Westinghouse dispute. Per our phone conference with ORS on 7/10/19@ 11:00am, Santee Cooper was given direction to have our legal team send the pleadings in the case to satisfy this request. Rebecca Roser sent these pleadings on 7/10/19.

1-5 Please complete Attachment A of the attached Excel workbook. The amounts provided should be as of March 31, 2019.
See file: "20190625 - ORS Request Attachments A-E 7-19-19.xls"

Per our phone conference with ORS on 7/10/19@ 11:00am, Santee Cooper was given clarifying direction requesting electric system only.

a. Identify the dollar value funded by debt attributed to the Units, including Transmission and Nuclear Inventory. All of VCS 2/3 was funded entirely by debt.

b. Provide Santee Cooper's debt to equity ratio as of December 31, 2018. Santee Cooper's electric only debt to equity is 75/25.

c. Identify the dollar value of the Owner's Costs attributed to the Units, including Transmission and Nuclear Inventory. – Santee Cooper did not segregate out project cost between EPC and Owners Cost.

d. Identify the dollar value of all assets associated with the Westinghouse dispute. Per our phone conference with ORS on 7/10/19@ 11:00am, Santee Cooper was given direction to have our legal team send the pleadings in the case to satisfy this request. Rebecca Rosen sent these pleadings on 7/10/19.

1-6 Please complete Attachment C of the attached Excel workbook detailing any and all transfers to utility plant in service or inventory from the Units including transmission and nuclear fuel inventory. As discussed during our phone conversation, this request uses the term "used and useful, while Santee Cooper's enabling legislation uses the term Used or Useful. Therefore, no determination as to "used and useful" is being made. Our understanding of H. 4287 is that the professional services experts retained by the DOA and the Office of Regulatory Staff will determine what is used and useful for purposes of the process established by H.4287.

Without making any determination as to used and useful, Attachment C was completed with the assets that were transferred from units 2/3 to unit 1 in December 2017. See file 20190625 - ORS Request Attachments A-E 7-19-19.xls. The listing of assets came from our true up with SCANA on ownership percentage changes from 45% (units 2/3) to 33% (unit 1). Costs are as of the true up date and any costs charged to us after that point are not included as they are not easily identifiable in our project system. Depreciation is also estimated because we use composite deprecation. Accumulated depreciation is estimated based on the nuclear depreciation rate and when the asset is put into service.

a. Identify and provide the dollar value for any assets that have been transferred into utility plant in service or inventory, but do not fit the definition of "used and useful." Provide an explanation for why the assets are not considered "used and useful.".

1-7 Please provide Santee Cooper's interpretation or understanding of a "retail customer" as used in Section 2(A) of H. 4287: Santee Cooper is not certain what was intended by the term "retail customers" in H4287 and would assume that the DOA will clarify its understanding of this term prior to requesting information from Santee Cooper and the bidders on the project. In general retail customers are end users of electricity and are not purchasing electricity for resale. Santee Cooper generally includes Residential, Commercial, Lighting and Industrial customers (those that meet the qualification of or Large Light and Power rate schedules) when referring to retail electric customers.

> "*Require that the bidder's projected ratebase for all of Santee Cooper's* ***retail customers*** *exclude any portion of debt attributed to V.C. Summer nuclear units 2 and 3 that is not considered to be used and useful, as determined by the professional services experts and the Office of Regulatory Staff;*"

1-8 Please describe the cost allocation method used by Santee Cooper to allocate costs to its retail (residential, commercial, industrial, lighting, etc.) and wholesale (electric cooperatives, municipalities, etc.) customers.
Per our phone conference with ORS on 7/10/19@ 11:00am, Santee Cooper was given clarifying direction and was asked to provide our most recent rate study which was in 2015. It was also determined that this response will be applicable to 1-9, 1-10 & 1-11.

See attached file "Santee Cooper 2015 Electric COS Study_FINAL.pdf" as well as the Technical Appendix in file name "Technical Appendix- Final.xls". This rate study includes the cost of service methodology as well as allocation among classes.

1-9 Please provide a detailed breakdown or schedule of retail and wholesale allocation factors.

1-10 Please complete Attachment D of the attached Excel workbook. The amounts provided should be as of December 31, 2018 and allocated to retail customers.

a. Identify the dollar value funded by debt for the retail allocated amounts attributed to the Units, including Transmission and Nuclear Inventory.
b. Identify the dollar value of the retail allocated Owner's Costs attributed to the Units, including Transmission and Nuclear Inventory.
c. Identify the retail allocated dollar value of all assets associated with the Westinghouse dispute.

1-11 Please complete Attachment E of the attached Excel workbook. The amounts provided should be as of March 31, 2019 and allocated to retail.

a. Identify the dollar value funded by debt for the retail allocated amounts attributed to the Units, including Transmission and Nuclear Inventory.
b. Identify the dollar value of the retail allocated Owner's Costs attributed to the Units, including Transmission and Nuclear Inventory.
Identify the retail allocated dollar value of all assets associated with the Westinghouse dispute.

SANTEE COOPER

EXPENDITURES BY YEAR 2007-MARCH 2019

ORS REQUEST ITEM 1-1 (1)

Year	VC Summer 2- Capital(2)	VC Summer 3- Capital(2)	VC Summer 2 & 3 O&M
2007	13,747,868.01	0.00	0.00
2008	42,950,299.37	30,856,990.30	0.00
2009	213,486,654.09	73,162,520.17	0.00
2010	212,805,394.68	49,250,292.69	0.00
2011	212,953,639.18	106,947,310.97	0.00
2012	206,079,676.94	142,729,187.05	0.00
2013	225,391,136.08	163,984,067.01	0.00
2014	232,276,534.59	166,668,272.75	0.00
2015	170,034,548.37	213,091,725.27	0.00
2016	414,160,521.14	339,830,768.72	0.00
2017	189,889,349.63	263,893,783.89	0.00
2018	3,916,094.60	4,347,500.49	5,533,297.70
2019 Thru Mar	2,577,068.13	629,015.94	1,894,022.34
	2,140,268,784.81	1,555,391,435.25	7,427,320.04

(1) There is no Transmission related to VC Summer 2 & 3 only. All Transmission assets are being utilizec
planned prior to the Nuclear project. The Switchyard located at the VC Summer site is being utilized by '
(2) Original Capital expenditures including prior to suspension, post-suspension, and assets transferred '

Nuclear Fuel Inventory	Capitalized Interest for VC Summer 2	Capitalized Interest for VC Summer 3
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
0.00	0.00	0.00
17,596,058.40	0.00	0.00
10,047,065.80	0.00	0.00
29,841,811.71	60,572,158.65	23,086,490.88
341,924.72	41,699,182.33	17,571,590.89
307,060.46	23,276,713.83	20,204,377.34
44,969,191.65	117,529,854.90	70,190,300.06
0.00	40,712,118.12	27,198,675.15
0.00	0.00	0.00
0.00	0.00	0.00
103,103,112.74	283,790,027.83	158,251,434.32

d by all other Santee Cooper generating facilities and system upgrades were
VC Summer 1.
to VC Summer 1.

ORS Audit Information Request - Attachment A - Response 4
Santee Cooper - Projected Rate Base
As of December 31, 2018 (1)
H. 4287

	(Thousands)				
	Total As of December 31, 2018 *(Electric Only)*	Attributable to Units 2&3	Attributable to Related Transmission	Attributable to Related Nuclear Fuel	Detailed Description of Amounts Attributable to Units 2&3, Related transmission, and Nuclear Fuel
Gross Utility Plant in Service (Net of Contributed Capital, if applicable)	$ 7,608,936	$ -	$ -	$ -	
Long Lived Asset - ARC Retirement Cost	$ 265,116	$ -	$ -	$ -	
Accumulated Depreciation (Net of Amortization of Contributed Capital, if applicable)	$ (3,909,211)	$ -	$ -	$ -	
Net Utility Plant in Service	$ 3,964,841	$ -	$ -	$ -	
Inventory/Material & Supplies	$ 372,556	$ -	$ -	$ 34,560	
Prepayments	$ 74,864	$ -	$ -	$ -	
CWIP	$ 1,015,977	$ -	$ -	$ -	
Cash Working Capital (12.5% of electric operating expenses)	$ 174,230	$ -	$ -	$ -	
Regulatory Assets					
1) Cost to be recovered from future revenue	$ 223,422	$ -	$ -	$ -	
2) Regulatory asset-asset retirement obligation	$ 710,326	$ -	$ -	$ -	
3) Regulatory asset-OPEB	$ 153,235	$ -	$ -	$ -	
4) Regulatory asset-nuclear	$ 4,235,339	$ 4,166,796	$ -	$ 68,543	Includes current and non-current regulatory asset. Regulatory asset related to Units 2 & 3 Interest was $37.0 million. Regulatory asset related to Units 2 & 3 Impairment was $4.198 billion (including nuclear fuel).
5) Other non-current and regulatory assets	$ 189,626	$ -	$ -	$ -	
Deferred Outflows					
1) Deferred outflows-pension	$ 41,859	$ -	$ -	$ -	
2) Deferred outflows-OPEB	$ 23,175	$ -	$ -	$ -	

3) Accumulated decrease in fair value of hedging derivatives	$ 39,440	$ -	$ -	$ -	
4) Unamortized loss on refunded and defeased debt	$ 134,694	$ -	$ -	$ -	
5)					
Customer Deposits	$ 21,227	$ -	$ -	$ -	
Regulatory Liabilities					
1) Other credits and noncurrent liabilities	$ 91,672	$ 6,537	$ -	$ -	
2)					
3)					
4)					
5)					
Deferred Inflows					
1) Deferred inflows-pension	$ 16,740	$ -	$ -	$ -	
2) Deferred inflow-OPEB	$ 249	$ -	$ -	$ -	
3) Accumulated increase in fair value of hedging derivatives	$ 1,414	$ -	$ -	$ -	
4) Nuclear decommissioning costs	$ 215,551	$ -	$ -	$ -	
5) Regulatory inflows-Toshiba settlement	$ 732,325	$ 732,325	$ -	$ -	

(1) Please note, the Santee Cooper Financial Statements for total system (electric and water) as of December 31, 2018 have been audited, but the breakdown for electric system (above) was prepared from internal documentation. There is no Transmission related to VC Summer 2 & 3 only. All Transmission assets are being utilized by all other Santee Cooper generating facilities and system upgrades were planned prior to the Nuclear project. The Switchyard located at the VC Summer site is being utilized by VC Summer 1.

ORS Audit Information Request - Attachment B - Response 5
Santee Cooper - Projected Rate Base
As of March 31, 2019 [(1)]
H. 4287

	(Thousands)				
	Total As of March 31, 2019 *(Electric Only)*	Attributable to Units 2&3	Attributable to Related Transmission	Attributable to Related Nuclear Fuel	Detailed Description of Amounts Attributable to Units 2&3, Related transmission, and Nuclear Fuel
Gross Utility Plant in Service (Net of Contributed Capital, if applicable)	$ 7,617,226	$ -	$ -	$ -	
Long Lived Asset - ARC Retirement Cost	$ 265,116	$ -	$ -	$ -	
Accumulated Depreciation (Net of Amortization of Contributed Capital, if applicable)	$ (3,941,136)	$ -	$ -	$ -	
Net Utility Plant in Service	$ 3,941,206	$ -	$ -	$ -	
Inventory/Material & Supplies	$ 384,311	$ -	$ -	$ -	
Prepayments	$ 67,159	$ -	$ -	$ -	
CWIP	$ 1,058,022	$ -	$ -	$ -	
Cash Working Capital (12.5% of electric operating expenses)	$ 36,247	$ -	$ -	$ -	
Regulatory Assets					
1) Cost to be recovered from future revenue	$ 226,232	$ -	$ -	$ -	
2) Regulatory asset-asset retirement obligation	$ 710,799	$ -	$ -	$ -	
3) Regulatory asset-OPEB	$ 153,235	$ -	$ -	$ -	
4) Regulatory asset-nuclear	$ 4,234,607	$ 4,166,064	$ -	$ 68,543	Includes current and non-current regulatory asset. Regulatory asset related to Units 2 & 3 Interest was $37.0 million. Regulatory asset related to Units 2 & 3 Impairment was $4.197 billion (including nuclear fuel).
5) Other non-current and regulatory assets	$ 183,261	$ -	$ -	$ -	
Deferred Outflows					
1) Deferred outflows-pension	$ 41,859	$ -	$ -	$ -	

2) Deferred outflows-OPEB	$ 23,175	$ -	$ -	$ -	
3) Accumulated decrease in fair value of hedging derivatives	$ 32,043	$ -	$ -	$ -	
4) Unamortized loss on refunded and defeased debt	$ 131,621	$ -	$ -	$ -	
5)					
Customer Deposits	$ 22,099	$ -	$ -	$ -	
Regulatory Liabilities					
1) Other credits and noncurrent liabilities	$ 86,826	$ 6,537	$ -	$ -	
2)					
3)					
4)					
5)					
Deferred Inflows					
1) Deferred inflows-pension	$ 16,740	$ -	$ -	$ -	
2) Deferred inflow-OPEB	$ 249	$ -	$ -	$ -	
3) Accumulated increase in fair value of hedging derivatives	$ 3,349	$ -	$ -	$ -	
4) Nuclear decommissioning costs	$ 221,472	$ -	$ -	$ -	
5) Regulatory inflows-Toshiba settlement	$ 704,054	$ 704,054	$ -	$ -	

(1) Please note, the Santee Cooper Financial Statements as of March 31, 2019 are unaudited. There is no Transmission related to VC Summer 2 & 3 only. All Transmission assets are being utilized by all other Santee Cooper generating facilities and system upgrades were planned prior to the Nuclear project. The Switchyard located at the VC Summer site is being utilized by VC Summer 1.

ORS Audit Information Request - Attachment C - Response 6
Transfers from Units 2&3, Related Transmission, and Related Nuclear Fuel Inventory
H. 4287

Asset Description	How Is This Asset Currently Being Used?	Santee Cooper Calculated 1/3 Share	Accumulated Depreciation at 12/31/18 (See note A)	Accumulated Depreciation at 3/31/19 (See note A)
WORK HOUR TRACKING SOFTWARE	SOFTWARE	$384,517.69	$8,523.48	$9,802.00
MGMT. OBSERVATION DATABASE SOFTWARE	SOFTWARE	$65,689.85	$1,456.13	$1,674.54
Nuclear Operations Building (NOB)	FACILITIES	$13,184,015.50	$569,879.07	$613,715.92
VCS COUNT ROOM HARDWARE	TOOLS	$63,076.00	$2,726.46	$2,936.19
VCS COUNT ROOM SOFTWARE	SOFTWARE	$66,811.79	$0.00	$0.00
VISION LICENSES	SOFTWARE	$44,971.25	$996.86	$1,146.39
EMPACT 3.0 SOFTWARE	SOFTWARE	$431,415.69	$9,563.05	$10,997.50
CHAMPS REPLACEMENT	SOFTWARE	$6,225,754.03	$0.00	$0.00
Emergency Services Building	FACILITIES	$1,869,227.71	$0.00	$0.00

Security Training Facility (includes classroom trailers)	FACILITIES	$1,788,257.82	$0.00	$0.00
WinCDMS	SOFTWARE	$11,666.67	$258.61	$297.40
PRIMAVERA P6 SOFTWARE	SOFTWARE	$289,858.75	$6,425.20	$7,388.98
PLATEAU SOFTWARE UPGRADE	SOFTWARE	$94,515.26	$2,828.37	$3,142.63
WORKFORCE TIME & ATTEND. SOFTWARE	SOFTWARE	$321,988.53	$7,137.41	$8,208.02
EMPCENTER KIOSK REPLACEMENT	TOOLS	$18,770.31	$416.08	$478.49
MIDAS SOFTWARE	SOFTWARE	$79,042.14	$0.00	$0.00
VSDS SOFTWARE	SOFTWARE	$50,744.72	$2,193.44	$2,362.17
SIREN SYSTEM COMPUTER REPLACEMENT	EQUIPMENT	$5,200.41	$115.28	$132.57
RECORDS SHREDDER REPLACEMENT	TOOLS	$5,909.40	$130.99	$150.64
MAINTENANCE RULE	SOFTWARE	$203,548.77	$0.00	$0.00

WEB EOC	SOFTWARE	$22,682.81	$502.80	$578.22
TSC RAD MONITORS	EQUIPMENT	$12,858.75	$555.82	$598.57
DIGITAL FLOWMETER & SAMPLING ASBLY.	TOOLS	$2,506.34	$55.56	$63.89
VISION ENTERPRISE LICENSE	SOFTWARE	$20,770.00	$460.40	$529.46
COMMUNICATIONS TOWER FROM SCI	FACILITIES	$179,926.68	$7,777.33	$8,375.59
EMPACT SOFTWARE	SOFTWARE	$104,079.03	$3,114.56	$3,460.63
HP WHOLE BODY COUNT EQUIPMENT	TOOLS	$27,123.02	$0.00	$0.00
HP WHOLE BODY COUNT SOFTWARE	SOFTWARE	$18,360.68	$0.00	$0.00
WASTEWATER TREATMENT FACILITY (Outfall 5)	FACILITIES	$876,018.94	$0.00	$0.00
ADD'L TIME & ATTENDANCE KIOSKS	TOOLS	$9,183.49	$203.57	$234.10
MET TOWER SOFTWARE	SOFTWARE	$33,801.49	$0.00	$0.00

COFFEE MAKERS FOR NOB	TOOLS	$811.03	$17.98	$20.67
WASTEWATER TREATMENT FACILITY (Outfall 1)	FACILITIES	$328,447.44	$0.00	$0.00
KEY PERFORMANCE INDICATOR	SOFTWARE	$87,563.38	$0.00	$0.00
EMPACT 4.3 SOFTWARE	SOFTWARE	$50,775.20	$0.00	$0.00
EQUIPMENT ON-LINE MONITORING	SOFTWARE	$66,676.88	$0.00	$0.00
AIR PACKS FOR EP	TOOLS	$29,316.17	$0.00	$0.00
WebEOC ENF BOARD	SOFTWARE	$10,840.00	$0.00	$0.00
Unit 2 & 3 OWS	FACILITIES	$14,529,843.74	$322,078.20	$370,389.93
Nuclear Learning Center (Unit 2 & 3 Expansion)	FACILITIES	$3,283,043.67	$72,774.13	$83,690.25
Network Hardware from Service Bldg	TOOLS	$156,710.00	$3,473.74	$3,994.80
Fiber Hut 2-table top	FACILITIES	$205,125.00	$4,546.94	$5,228.98

Fiber Hut 5-table top	FACILITIES	$227,073.33	$5,033.46	$5,788.48
Fiber Hut 3-constr city bldg 15&23	FACILITIES	$58,333.33	$1,293.06	$1,487.01
Fiber Hut 4-constr transformer & cell tower	FACILITIES	$58,333.33	$1,293.06	$1,487.01

Note A: Santee Cooper uses composite depreciation. Accumulated depreciation is estimated based on the nuclear depreciation rate and when the asset is put into service.

2015 Electric System Cost of Service and Rate Design Study

South Carolina Public Service Authority (Santee Cooper)

June 12, 2015

leidos

2015 Electric System Cost of Service and Rate Design Study

South Carolina Public Service Authority (Santee Cooper)

June 12, 2015

leidos

South Carolina Public Service Authority (Santee Cooper)
One Riverwood Drive
Monks Corner, South Carolina 29461

Subject: **2015 Electric System Cost of Service and Rate Design Study**

Ladies and Gentlemen:

Pursuant to the provisions of an agreement between the South Carolina Public Service Authority (“Authority” or “Santee Cooper”) and Leidos Engineering, LLC (“Leidos” or “the Firm”) and the direction provided by the management and staff of the Authority, the Firm has completed a study of the Authority’s electric rates applicable to all retail customers (the “Study”), which does not include the wholesale customer Central Electric Power Cooperative, Inc. (“Central”) or any other wholesale contract customers served by the Authority. The Study addresses the calendar years 2016, 2017 and 2018.

The Firm has summarized the results of the analyses and conclusions in the enclosed report, which is submitted for your consideration and deliberation. The report summarizes the basis for the proposed rates for electric service that are necessary to recover the near future revenue requirements from the appropriate customer classes and are designed to be just and reasonable.

In preparing the Study, the Firm relied upon historical and projected data for the development of operating revenues, operating expenses, and capital requirements. Historical data was obtained from various Authority reports, actual customer billing data, load research information, and discussions with members of the Authority’s management and staff. Projected data in part was obtained from 2014 Load Forecast (LF1401) with known adjustments, the Authority’s forecast of fuel availability and cost, the results of the Authority’s production costing analysis, the summarized analysis of customer billing records, and the financial projections of Electric System operation, known as the 2015 Financial Forecast 1501.

Major factors driving the need for rate revisions and for this Study include:

(i) Continued construction of Summer Nuclear Units 2 and 3, in which the Authority retains a 45 percent ownership stake,

(ii) Slow to moderate load growth, and

(iii) A projected shortfall in revenue.

The impact of the financial assumptions utilized for this Study result in a projected cost of service for the Authority that exceeds the revenue projected to be recovered by the existing customers. Utilizing an allocated methodology as described herein, the projected percentage rate increase by service class for the 2016, 2017 and 2018 calendar years is provided in Table 1 below.

Table 1
Existing and Proposed Firm Rate Revenue Projections

		Year to Year Percent Increases		
	Service	2016	2017	2018
1	Residential	6.7%	2.2%	1.3%
2	Commercial	6.6%	2.7%	0.8%
3	Lighting	7.0%	2.6%	0.4%
4	Industrial (Firm)	3.8%	2.2%	0.9%
5	Total	6.2%	2.4%	1.0%

The Firm has prepared proposed electric rates that are designed to reflect, to the extent permitted: (i) the lowest reasonable price consistent with the projected revenue requirement, (ii) the encouragement of economic development, and job attraction and retention, (iii) simple and understandable rate design, (iv) equitable treatment of customer classes and individual customers within classes, (v) an avoidance of undue price fluctuations, (vi) the efficient use of electric service, and (vii) compliance with applicable orders and requirements of local, state, and federal regulatory authorities. The proposed rates have been designed to be implemented in three phases. The first phase is proposed to become effective April 1, 2016, the second phase is proposed to become effective April 1, 2017, and the third phase is proposed to become effective April 1, 2018.

Based upon the results of the studies and analyses as summarized in this report, and upon the numerous underlying financial and load assumptions and other considerations relied upon in making such analyses and incorporated by reference herein, Leidos is of the following opinion:

(i) The existing rates applicable to retail customers produce revenues that under-recover the projected revenue requirements for Test Years 2016, 2017 and 2018; and

(ii) Based on the results of the cost of service analysis conducted for this Study and the policy decisions and direction provided by Authority management and staff, the proposed rates which are to become effective on April 1 of 2016, 2017 and 2018 as identified herein, are just and reasonable;

We wish to take this opportunity to express our true appreciation for the spirited cooperation and valuable assistance given us throughout the course of this Study by each member of the Authority's management and staff.

Respectfully submitted,

Sincerely,

/s/ Leidos Engineering, LLC

2015 Electric System Cost of Service and Rate Design Study

Santee Cooper

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EXECUTIVE SUMMARY

Pursuant to the provisions of an agreement between the South Carolina Public Service Authority ("Authority" or "Santee Cooper") and Leidos Engineering, LLC ("Leidos" or "the Firm") and the direction provided by the management and staff of the Authority, the Firm has completed a study of the Authority's electric rates applicable to all retail customers (the "Study"), which does not include the wholesale customer Central Electric Power Cooperative, Inc. ("Central") or any other wholesale contract customers served by the Authority. The Study addresses the calendar years 2016, 2017 and 2018.

The Firm has summarized the results of the analyses and conclusions in the enclosed report. The report summarizes the basis for the proposed rates for electric service that are necessary to recover the near future revenue requirements from retail customer classes. The proposed rates were designed to be just and reasonable. This is in accordance with the direction provided by the Authority's management and staff, the historic and existing policies of the Authority, and in consideration of guidelines advocated by the Federal Energy Regulatory Commission ("FERC"), and the South Carolina Public Service Commission ("PSC").

In preparing the 2015 Electric System Cost of Service and Rate Design Study (the "Study"), the Firm relied upon historical and projected data for the development of operating revenues, operating expenses, and capital requirements. Historical data was obtained from various Authority reports, actual customer billing data, load research information, and discussions with members of the Authority's management and staff. Projected data in part was obtained from 2014 Load Forecast (LF1401) with known adjustments, the Authority's forecast of fuel availability and cost, the results of the Authority's production costing analysis, the summarized analysis of customer billing records, and the financial projections of Electric System operation, known as the 2015 Financial Forecast 1501.

Major factors driving the need for rate revisions and for this Study include:

(i) Continued construction of Summer Nuclear Units 2 and 3, in which the Authority retains a 45 percent ownership stake,

(ii) Slow to moderate load growth, and

(iii) A projected shortfall in revenue.

It should be recognized that the projections contained herein have been based on numerous assumptions and considerations traditionally used in the rate making process. Thus, the projections are intended to develop unit costs and rates necessary to recover the cost of providing service to the Authority's retail customer classes and any new municipal wholesale customers over time, and are not intended to be statements of actual operational performance. Revenues from services provided to Central and other existing municipal wholesale customers are identified herein.

The Authority's existing rates for retail and municipal wholesale customers were the second of two base rate adjustments adopted on September 11, 2012 and became effective December 1, 2013. A structural change to the on-peak hours effective under the Authority's Industrial Firm Service (L) rate was modified as of February 1, 2014.

The 2015 Study consists of a summary report and three appendices:

Appendix A – Bill Comparisons

Appendix B – Proposed Rate Schedules

Appendix C – Technical Appendix (Available Upon Request)

Summary of Findings

The various assumptions, adjustments and considerations are discussed in Section 2 regarding projected requirements, sales and customers, and in Section 3 regarding the projected revenues and expenditures. Based on the foregoing, the total system revenue requirements for calendar years 2016, 2017 and 2018 and the projected revenues, assuming existing rates, are summarized on Table ES-1:

Table ES-1
Total System Costs ($000)(1)

	Total System Revenue Requirements	2016	2017	2018
	Operations & Maintenance Expenses			
1	Fuel Expenses	$759,697	$784,715	$793,329
2	Purchased Power	136,796	140,282	135,388
3	Other Production O&M Expenses	229,840	233,441	238,907
4	Total Production Expenses	1,126,333	1,158,438	1,167,624
5	Transmission Expenses	33,892	33,104	32,812
6	Distribution Expenses	16,272	16,311	16,800
7	Customer Acct. & Information Exp.	16,469	16,852	17,358
8	Sales Expenses	15,106	14,594	15,352
9	Administration & General Expenses	107,946	110,854	114,073
10	Total Operations and Maintenance Expenses	$1,316,018	$1,350,152	$1,364,019
11	Sums in Lieu of Taxes and Other	24,650	25,620	26,181
12	Debt Service	437,038	468,260	482,245
13	Lease Payments	0	0	0
14	Working Capital Requirement	0	4,074	2,311
15	Total Revenue Requirement Before CIFR	$1,777,706	$1,848,106	$1,874,756
16	CIFR Requirement	$175,817	$182,780	$185,415
17	*Gross Revenue Requirements*	1,953,523	2,030,886	2,060,171
18	Less: Interest and Miscellaneous Income	(10,225)	(20,883)	(17,667)
19	Less: Other Operating Revenues	(15,783)	(16,585)	(17,375)
20	Less: Off-System Sales	(79,646)	(86,744)	(96,057)
21	Net On-System Requirements	1,847,870	1,906,674	1,929,073
22	Less: Non-Firm Sales	(166,425)	(173,630)	(175,255)
23	Total System Revenue Requirements	1,681,445	1,733,044	1,753,803
24	Less: Wholesale Power Sales	(1,177,410)	(1,208,765)	(1,213,137)
25	Total Cost of Service	504,035	524,279	540,681
26	Less: Revenues Under Current Rates	472,487	485,542	492,344
27	Estimated Revenue (Surplus) Deficiency	$31,548	$38,737	$48,337
28	% Rev. (Surplus) Deficiency Under Current Rates	6.7%	8.0%	9.8%

(1) Numbers may not add due to rounding.

Tables ES-2, ES-3 and ES-4 below set forth the difference between the cost of providing service and the revenue produced by the existing rates by customer class for 2016, 2017 and 2018.

Table ES-2
Retail Cost of Service and Existing Firm Rate Revenue Projections(1)

		Calendar Year 2016 ($000)(1)			
		Cost of	Existing	Difference	
	Service	Service(2)	Rate Revenue(2)	Amount	Percentage
1	Residential	$216,305	$202,087	$14,218	7.0%
2	Commercial	192,634	179,682	12,952	7.2%
3	Lighting	11,895	10,952	943	8.6%
4	Total Distribution	420,834	392,721	28,113	7.2%
5	Industrial (Firm)	83,199	79,766	3,433	4.3%
6	Total	$504,033	$472,487	$31,546	6.7%

Table ES-3
Retail Cost of Service and Existing Firm Rate Revenue Projections(1)

		Calendar Year 2017 ($000)(1)			
		Cost of	Existing	Difference	
	Service	Service(2)	Rate Revenue(2)	Amount	Percentage
1	Residential	$226,141	$208,502	$17,639	8.5%
2	Commercial	200,308	184,491	15,817	8.6%
3	Lighting	12,054	11,128	926	8.3%
4	Total Distribution	438,503	404,121	34,382	8.5%
5	Industrial (Firm)	85,776	81,421	4,355	5.3%
6	Total	$524,279	$485,542	$38,737	8.0%

Table ES-4
Retail Cost of Service and Existing Firm Rate Revenue Projections(1)

		Calendar Year 2018 ($000)(1)			
		Cost of	Existing	Difference	
	Service	Service(2)	Rate Revenue(2)	Amount	Percentage
1	Residential	$235,005	$213,141	$21,864	10.3%
2	Commercial	205,557	186,259	19,298	10.4%
3	Lighting	12,394	11,198	1,196	10.7%
4	Total Distribution	452,956	410,598	42,358	10.3%
5	Industrial (Firm)	87,723	81,746	5,977	7.3%
6	Total	$540,679	$492,344	$48,335	9.8%

(1) Numbers may not add due to rounding.
(2) Amounts shown are from firm service and have been reduced by revenues from Non-Class Sales. Excludes revenues from rates code RT.

Rate Design

The Firm has prepared proposed electric rates that are designed to reflect, to the extent permitted: (i) the lowest reasonable price consistent with the projected revenue requirement, (ii) the encouragement of economic development, and job attraction and retention, (iii) simple and understandable rate design, (iv) equitable treatment of customer classes and individual customers within classes, (v) an avoidance of undue price fluctuations, (vi) the efficient use of electric service, and (vii) compliance with applicable orders and requirements of local, state, and federal regulatory authorities. The proposed rates have been designed to be implemented in three phases. The first phase is proposed to become effective April 1, 2016, the second phase is proposed to become effective April 1, 2017, and the third phase is proposed to become effective April 1, 2018.

The principal effects of adopting the rates proposed herein are:

(i) Rate structures and levels, in general, will continue to be based, in part, on allocated embedded cost of service techniques,

(ii) The monthly customer charge of Residential and Commercial rates that do not currently include a demand charge will be increased to improve fixed cost recovery, and the differential between summer and non-summer energy charges will be increased from $0.01 to $0.02/kilowatt-hour,

(iii) The Residential RR and RN (Good Cents) rates will begin a period of transition, in which these customers will be moved to the RG rate by the end of the period of this Study (2018),

(iv) The Residential Net Billing Rate and Residential Demand Service Rider will be eliminated and replaced, as necessary, by the Distributed Generation Rider ("DG Rider") and the Residential Time-of-Use rate, respectively,

(v) The Large Light and Power Firm service demand charge for the first 300 kilowatts of demand will increase, and incremental demand above 300 kilowatts will be charged at a reduced rate,

(vi) The Large Light and Power Curtailable Supplemental Power Rider will be eliminated,

(vii) The interruptible service rider to the Large Light and Power rate has been modified to reflect an updated analysis of the avoided costs of a combustion turbine ("CT"),

(viii) Interruptible service will include a new provision for longer-duration curtailments, which will provide a longer notification period for economic curtailments that may be of greater duration than the current service for the months of December, January, and February,

(ix) The Economy Power Rider will be updated to better align the service with the Authority's Open Access Transmission Tariff,

(x) A new Economy Power product will be made available to be billed as energy (EP-AU),

(xi) Modifications to the ML rate will be made to better align with the proposed Industrial firm rate, and

(xii) A rider will be implemented to dictate the terms and conditions under which customers installing distributed generation will receive service from the Authority.

Tables ES-5, ES-6 and ES-7 are a comparison of the projected revenues produced by applying the projected billing units to the existing and proposed increase by customer class for 2016, 2017 and 2018. While ES-6, and ES-7 provide cumulative revenue increases for 2016 and 2017, Table ES-8 demonstrates incremental revenue increases for each year 2016 and 2017.

Table ES-5
Existing and Proposed Firm Rate Revenue Projections ($000)[(1)]

		Calendar Year 2016 ($000)[(1)]			
		Proposed	Existing	Difference	
	Service	Rate Revenue[(2)]	Rate Revenue[(2)]	Amount	Percentage
1	Residential	$215,628	$202,087	$13,541	6.7%
2	Commercial	191,613	179,682	11,931	6.6%
3	Lighting	11,715	10,952	763	7.0%
4	Total Distribution	418,956	392,721	26,235	6.7%
5	Industrial (Firm)	82,815	79,766	3,049	3.8%
6	Total	$501,771	$472,487	$29,284	6.2%

Table ES-6
Existing and Proposed Firm Rate Revenue Projections ($000)[(1)]

		Calendar Year 2017 ($000)[(1)]			
		Proposed	Existing	Difference	
	Service	Rate Revenue[(2)]	Rate Revenue[(2)]	Amount	Percentage
1	Residential	$227,363	$208,502	$18,861	9.0%
2	Commercial	202,003	184,491	17,512	9.5%
3	Lighting	12,216	11,128	1,088	9.8%
4	Total Distribution	441,582	404,121	37,461	9.3%
5	Industrial (Firm)	86,370	81,421	4,949	6.1%
6	Total	$527,952	$485,542	$42,410	8.7%

Table ES-7
Existing and Proposed Firm Rate Revenue Projections ($000)(1)

		Calendar Year 2018 ($000)(1)			
		Proposed	Existing	Difference	
	Service	Rate Revenue(2)	Rate Revenue(2)	Amount	Percentage
1	Residential	$235,363	$213,141	$22,222	10.4%
2	Commercial	205,593	186,259	19,334	10.4%
3	Lighting	12,345	11,198	1,147	10.2%
4	Total Distribution	453,301	410,598	42,703	10.4%
5	Industrial (Firm)	87,528	81,746	5,782	7.1%
6	Total	$540,829	$492,344	$48,485	9.8%

(1) Numbers may not add due to rounding.
(2) Amounts shown are for firm service.

Table ES-8
Existing and Proposed Firm Rate Revenue Projections

		Year to Year Percent Increases		
	Service	2016	2017	2018
1	Residential	6.7%	2.2%	1.3%
2	Commercial	6.6%	2.7%	0.8%
3	Lighting	7.0%	2.6%	0.4%
4	Industrial (Firm)	3.8%	2.2%	0.9%
5	Total	6.2%	2.4%	1.0%

Conclusions

Based upon the results of the studies and analyses as summarized in this report, and upon the numerous underlying financial and load assumptions and other considerations relied upon in making such analyses and incorporated by reference herein, the Firm is of the opinion that:

(i) The existing rates applicable to retail customers produce revenues that under-recover the projected revenue requirements for Test Years 2016, 2017 and 2018;

(ii) In Table ES-1, the existing rates for firm requirements customers produce revenues that are deficient in 2016 by approximately $31,548,000 or 6.7 percent, in 2017 by approximately $38,737,000 or 8.0 percent relative to 2016 revenues, and in 2018 by approximately $48,337,000 or 9.8 percent relative to 2016 revenues;

(iii) The proposed rates which are to become effective on April 1 of 2016, 2017 and 2018 are projected to meet the revenue requirements for the combined three-year period. Santee Cooper made an adjustment to proposed rates in 2016 and 2017 to account for a timing lag in revenue recovery caused by calculating revenue requirements on the basis of the calendar year combined with proposed rate adjustments becoming effective in April of each year. The revenue shortfall projected to stem from such a timing lag in revenue recovery is proposed to be fully recovered in 2016 and 2017;

(iv) Based on the adjustment in rate design to account for a timing lag in revenue recovery, on average, firm requirements customers other than Central and other existing municipal wholesale customers would experience an incremental annual rate increase of approximately 6.2 percent in 2016, 2.4 percent in 2017, and 1.0 percent in 2018;

(v) Based on the results of the cost of service analysis conducted for this Study and the policy decisions and direction provided by Authority management and staff, the proposed rates which are to become effective on April 1 of 2016, 2017 and 2018 as identified herein, are just and reasonable; and

(vi) To the extent the assumptions as stated herein regarding future expenses and revenues in 2016, 2017 and 2018 are not realized, the proposed rates as developed herein may not be sufficient to meet revenue requirements within the period identified.

Leidos would like to take this opportunity to express its appreciation for the spirited cooperation and valuable assistance provided by each member of the Authority's management and staff throughout the course of this Study.

Section 1
INTRODUCTION

General

The South Carolina Public Service Authority, also known as Santee Cooper, is referred to herein as the "Authority" and "Santee Cooper." The Authority is a body corporate and politic created by Act No. 887 of the Acts of South Carolina for 1934 and acts supplemental thereto and amendatory thereof (the "Act"), and is codified at S.C. Code Ann. §§ 58-31-10 et seq. The Act, among other things, authorizes the Authority to produce, distribute, and sell electric power and to acquire, treat, and transmit, and sell wholesale potable drinking water. The Authority began electric operations in 1942 and the regional water system began operations in 1994.

The Act also grants certain powers to the Authority, including "... to fix, alter, charge, and collect tolls and other charges for the use of their facilities of, or for the services rendered by, or for any commodities furnished by, the ... Authority at rates to be determined by it, these rates to be at least sufficient to provide for payment of all expenses of the Authority, the conservation, maintenance, and operation of its facilities and properties, the payment of principal and interest on its notes, bonds, and other evidences of indebtedness or obligation, and to fulfill the terms and provisions of any agreements made with the purchasers or holders of any such notes, bonds, or other evidences of indebtedness or obligation; ..."[1]

Pursuant to the Act, the Authority is governed by a Board of Directors consisting of up to twelve members appointed by the Governor and confirmed by the State Senate. The Authority's powers are exercised through its Board of Directors.[2] In addition, the Act establishes an Advisory Board consisting of the Governor, the Attorney General, the State Treasurer, the Comptroller General and the Secretary of State.

Among other things, each Director is required to discharge his or her duties in good faith, with the care of a similarly situated, ordinarily prudent person, in a manner reasonably believed to be in the best interests of the Authority.[3] The "best interests" of the Authority are defined as a balancing of the following factors: " ... preservation of the financial integrity of the ... Authority and its ongoing operation of generating, transmitting, and distributing electricity to wholesale and retail customers on a reliable, adequate, efficient, and safe basis, at just and reasonable rates, regardless of class of customers; ... economic development and job attraction and retention within the ... Authority's present service territory or areas within the State authorized to be served by an electric cooperative or municipally owned electric utility that is a direct or indirect wholesale customer of the Authority ..."; and exercise of the Authority's

[1] S.C. Code Ann. § 58-31-30(13).
[2] S.C. Code Ann. § 58-31-60.
[3] S.C. Code Ann. § 58-31-55(A)(1)-(3).

statutory powers "in accordance with good business practices and the requirements of applicable laws, licenses, and regulations."[4]

Senior management of the Authority is vested in eight executive-level individuals. The President and Chief Executive Officer is appointed by the Board of Directors. The remaining seven members of the executive leadership team are appointed by the President and Chief Executive Officer with the approval of the Board of Directors. The Authority manages approximately 1,800 employees located throughout the State.

Electric System

Pursuant to the powers of the Act, the Authority owns, operates and maintains electric generation, transmission, distribution and general plant facilities that provide electric power and energy to three "Sales for Resale" customers: Central Electric Power Cooperative, Inc. ("Central"); the City of Bamberg, SC and the City of Georgetown, SC (collectively, the "Municipal Customers," and collectively with Central, the "Wholesale Customers"). The Authority directly serves at retail approximately 172,000 residential, commercial, industrial and lighting customers including 27 large industrial customers (collectively, the "retail customers" or "direct serve customers").

The Authority's primary business operations are the production, transmission and distribution of electric power and energy to other electric utility entities and to end-use customers, and the acquisition, treatment and distribution of potable drinking water to certain governmental entities for sale to ultimate customers. Consequently, for the purposes of accounting and certain management activities, the Authority operates the Electric System and the Water System as separate entities. Certain common costs are allocated between the Electric System and the Water System. The 2015 Electric System Cost of Service and Rate Design Study does not address the Water System.

Generation

The Authority's reported total summer maximum continuous rating, assuming all generating units are available, is 5,182 MW, of which 3,480 MW is provided by coal-fueled units, 129 MW by hydroelectric stations, 318 MW by a nuclear-fueled unit, 1,226 MW by oil, gas or oil/gas-fueled units and 29 MW from landfill methane gas-fueled units. The reported total winter maximum continuous rating assuming all generating units are available, is 5,424 MW of which 3,525 MW is provided by coal-fueled units, 129 MW by hydroelectric stations, 318 MW by a nuclear-fueled unit, 1,423 MW by oil, gas, or oil/gas-fueled units, and 29 MW by landfill methane gas-fueled units.

Purchased Power

The Authority receives 84 MW of firm supply from the U.S. Army Corps of Engineers (the "Corps") and 319 MW of firm hydroelectric power from the Southeastern Power Administration ("SEPA"). The SEPA allocation consists of 184 MW for wheeling to

[4] S.C. Code Ann. § 58-31-55(A)(3)(a)-(c).

the SEPA preference customers served by the Authority (Central and the Municipal Customers) and 135 MW purchased by the Authority for its direct serve customers. The Authority also receives 8 MW of dependable capacity from the Buzzards Roost Hydroelectric Generating Facility which it leases from Greenwood County, South Carolina and 38 MW of biomass-fueled capacity and associated energy under four power purchase agreements (the first commenced in September 2010 and the most recent in November 2013 with varying terms from fifteen to thirty years). There is also an agreement to purchase the output from a 2.5 MW solar photovoltaic facility that started producing power in December of 2013 and has a 20 year term. The Authority has also entered into a purchase agreement with JP Morgan Ventures Energy Corporation for 300 MW of capacity and associated energy that will end December 31, 2015.

Transmission

The Authority operates an integrated transmission system, which includes lines owned and leased by the Authority as well as those owned by Central. The transmission system includes approximately 1,285 miles of 230 kilovolt ("kV"), 1,847 miles of 115 kV, 753 miles of 69 kV, 10 miles of 46 kV and 97 miles of 34 kV and below, consisting of overhead and underground transmission lines. The Authority operates 104 transmission substations and switching stations serving 86 distribution substations and 468 Central members' delivery points. Monitoring and control of integrated power system operations is supported by 91 primary communication sites. The Authority plans the transmission system to operate during normal and contingency conditions that are outlined in electric system reliability standards adopted by the North American Electric Reliability Corporation ("NERC") and to maintain system voltages that are consistent with good utility practice.

Interconnections and Interchanges

The Authority's transmission system is interconnected with other major electric utilities in the region. It is directly interconnected with South Carolina Electric & Gas Company ("SCE&G") at eight locations; with Duke Energy Progress at eight locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with Duke Energy Carolinas, LLC ("Duke") at two locations. The Authority is also interconnected with SCE&G, Duke, Southern Company and SEPA through a five-way interconnection at SEPA's J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at SEPA's R. B. Russell Hydroelectric Project. Through these interconnections, the Authority's transmission system is integrated into the regional transmission system serving the southeastern areas of the United States and the Eastern Interconnection. The Authority has separate interchange agreements with each of the companies with which it is interconnected which provide for mutual exchanges of power.

The Authority is a party to the Virginia-Carolinas Reliability Agreement ("VACAR") which exists for the purpose of safeguarding the reliability of electric service of the parties thereto. Other parties to the VACAR agreement are SCE&G, Duke Energy

Progress, Duke Energy Carolinas, APGI-Yadkin Division, Dominion, Virginia Power, and Public Works Commission of the City of Fayetteville. The Authority is also a member of the SERC Reliability Corporation ("SERC"), which is one of eight regional entities under the NERC.

Distribution

The Authority owns distribution facilities in two service areas: The Berkeley District serving retail customers in St. Stephen, Bonneau Beach, Moncks Corner and Pinopolis; and the Horry-Georgetown Division serving retail customers in Conway, Myrtle Beach, North Myrtle Beach, Loris, Briarcliffe, Surfside Beach, Atlantic Beach, Pawleys Island, unincorporated areas along the Grand Stand and portions of rural Georgetown and Horry Counties.

The electric generation, transmission and distribution facilities owned by the Authority as well as certain generation and transmission facilities leased from Central, are operated by the Authority as a fully integrated electric system.

General Plant

The Authority owns general plant consisting of office facilities, transportation and heavy equipment, computer equipment, and communication equipment necessary to support the Authority's operations. The Authority has nine customer service offices throughout its direct service territory and corporate headquarters located in Moncks Corner, which include a garage, maintenance facilities, and warehouse facilities.

Customers

Retail / Direct Serve Customers

The Authority owns distribution facilities and serves customers residing in two non-contiguous areas covering portions of Berkeley, Georgetown, and Horry Counties. These service areas include 2,806 miles of distribution lines. Sales to residential, commercial, small industrial customers and certain other customers are made pursuant to rate schedules which include a fuel adjustment clause and demand sales adjustment clause.

Sales to large industrial customers are made pursuant to long-term contracts and provide for a minimum kilowatt ("kW") load for an initial period of not less than five years. All contracts contain rate provisions of the demand and energy type, and include fuel adjustment clauses, demand sales adjustment clauses and other provisions generally used in large industrial power rate schedules.

Two of the Authority's largest industrial customers are Century Aluminum operating at the Mt. Holly smelting plant ("Century") and Nucor Corporation pertaining to its Nucor Steel Berkeley Division ("Nucor"). The contract with Century, which terminates on December 31, 2015, provides for the delivery of approximately 400 MW of capacity and energy. Century has given notice that it will not renew its existing power contract for the Mt. Holly facility. As of the date of this report, the Authority and Century continue to engage in ongoing discussions to negotiate a new long-term power contract. The Authority also has a long-term power contract with Nucor which extends through April 30, 2017 and provides for two year rollover terms thereafter. The contract currently provides for delivery of approximately 300 MW of capacity and energy.

Sales for Resale (Wholesale)

The Authority supplies the total power and energy requirements of Central less amounts which Central purchases directly from SEPA, a small amount purchased from others and amounts provided by a Central member cooperative's ownership interest in a small run-of-the-river hydroelectric plant. The amounts of power and energy supplied by the Authority are determined under the terms of an agreement between the Authority and Central (the "Central Agreement") which became effective January 1981. The Authority and Central adopted an amendment to the Central Agreement in January 1988, which revised the cost of service methodology, lowered the cost responsibility and rates to Central and extended the contract for a 35-year period ending on March 31, 2023.

In September 2009, the Authority and Central entered into another agreement which, among other things, would permit Central to purchase the electric power and energy requirements necessary to serve five of its member cooperatives located in the upper part of the State and connected to the transmission system of Duke Energy Carolinas, LLC (the "Upstate Load") from a power supplier other than the Authority. The Upstate Load will transition to the new power supplier over a seven-year period which began in 2013, and by 2019 will amount to approximately 900 MW. The agreement also provides that neither party will exercise any right to terminate the Central Agreement, as amended, effective on or before December 31, 2030.

In May 2013, an additional amendment to the Central Agreement was adopted to better align future interests and formalize the resource planning process among the parties to plan and determine the need for new resources. The revision further defers rights to terminate the agreement until December 31, 2058.

In addition to Central, the Authority provides wholesale electric service to the City of Georgetown, SC, the City of Bamberg, SC, and SCE&G pursuant to long-term contracts. New service agreements were executed in 2013 with the City of Georgetown and the City of Bamberg for 10 and 20 years, respectively.

The Authority has a long-term power agreement with Piedmont Municipal Power Agency ("PMPA") pursuant to which the Authority will provide PMPA its supplemental electric power and energy requirements (ranging from approximately 200 MW to 300 MW) above PMPA's current resources. This agreement commenced on January 1, 2014, for a term of no less than 12 years.

The Authority also has an agreement pursuant to which it will provide Alabama Municipal Electric Authority ("AMEA") 50 MW unit-contingent capacity and associated energy (25 MW – 50 MW). This agreement commenced on January 1, 2014, for a term of 10 years.

Existing Rates

The Authority's Board of Directors is empowered and required to set rates as necessary to provide for expenses of the Authority, including debt service. The Authority's existing rates and charges for retail customers were adopted by the Authority's Board of Directors on September 11, 2012. A series of two base rate adjustments were approved for retail, industrial and municipal customers. The adjustments increased total charges for customers an average of 3.5 percent each year for a total increase of 7 percent to ensure rates were at least adequate to provide revenues sufficient to pay debt service, the cost of operation and maintenance of the Authority's System, and meet the Revenue Obligation requirements for transfers to the Capital Improvement Fund, and all other such costs as necessary. The first adjustment took effect December 1, 2012 and the second took effect on December 1, 2013. Rates charged to Central are within the terms and conditions of the Central Agreement, as discussed herein. Similarly, rates charged to the Municipal Customers are within the terms and conditions of their respective contracts.

The Authority offers time-of-use, non-firm and off-peak rates to its direct-served commercial and industrial customers to encourage them to reduce their peak demand. As of December 31, 2014, the Authority had 834 MW of "non-firm power" under contract with its industrial customers. The Authority has also implemented seasonal energy charges for most rates affecting residential, commercial, and industrial customers. Seasonal energy charges reflect a higher charge during the summer months. The Authority's rate schedules include a "fuel adjustment clause" which provides for increases or decreases to the base rate schedules to cover increases or decreases in the cost of fuel and purchased power to the extent such costs vary from a predetermined base cost. The Authority's rate schedules also include a "demand sales adjustment clause" which provides for increases or decreases to the base rate schedules to reflect increases or decreases in demand revenues from non-firm sales (such as interruptible and economy power rate schedules and riders) and off-system sales. Demand revenues from non-firm sales are reductions (credits) to customers' rates, to the extent such credits vary from predetermined base amounts.

In accordance with the Central Agreement, the rates and charges for electric service to Central are determined and adjusted annually pursuant to a cost of service methodology set forth in the Central Agreement. Similarly, in accordance with the contractual provisions, the rates and charges for wholesale electric service to the Municipal Customers are determined pursuant to the cost of service methodology set forth in their respective agreements. The cost of service methodology applicable to the Authority's Wholesale Customers is similar to, but different from, the methodology used in determining the rates and charges applicable to the Authority's direct serve residential, commercial, industrial, lighting, and any new municipal customers.

2015 Electric System Cost of Service and Rate Design Study

In keeping with the Board of Director's direction, the Authority initiated certain actions to reduce costs, to minimize uncertainty where possible, and to evaluate the level and timing of the next proposed rate increase. On October 17, 2014, the Board of Directors requested management to prepare a comprehensive review of the Authority's existing rate structures and adequacy of its existing rate levels, and to present a recommendation concerning proposed revised rate schedules applicable to all retail customers for consideration at its June 2015 meeting. The result of that request is the enclosed 2015 Electric System Cost of Service and Rate Design Study (the "Study").

In 2014, the Authority retained Leidos Engineering, LLC ("Leidos" or "the Firm"), to provide consulting services to assist the management and staff of the Authority to prepare a comprehensive Electric Rate Study, revise rates applicable to retail customers that recover the projected near term costs for the years 2016, 2017 and 2018, accounting for the cost of service, the goals and policies of the Board of Directors, recognized industry standards, and customer input resulting from periodic meetings with its customers. Rate matters pertaining to the Authority's Wholesale Customers and the respective confidential agreements are excluded from this engagement.

During the course of the assignment, the Firm worked closely with the Authority's management and staff and provided consulting services in the following general ratemaking areas: (i) the development of the near term (calendar years 2016, 2017, and 2018) annual revenue requirements, (ii) the refinement of its cost of service methodology, (iii) guidance on industry-accepted best practices in rate design, (iv) the development of proposed rates and rate riders for electric service designed to be just and reasonable and equitably recover the near term cost of service, regardless of customer class, and (v) the participation in public meetings pertaining to this Study and the proposed rates and charges.

To meet schedule requirements and to minimize costs, the Firm relied on, and used, information prepared by, and/or prepared for, the Authority. The Firm believes such information to be reliable, but has not verified its accuracy. The Firm has performed a reasonable review of the Authority's cost of service model used to perform this rate Study. To the Firm's knowledge, the summaries presented herein accurately reflect the information obtained from such sources. As some of the information has been based on assumptions and estimates of future occurrences, such information is subject to change based on indeterminate future events that could include changes in forecasts of sales, customers, usage characteristics, operating costs, capital and financing costs and other costs of the Electric System.

In the preparation of this Study and the design of proposed rates, the Firm has considered and has utilized, where appropriate, the practices established or advocated by the Federal Energy Regulatory Commission ("FERC"), the National Association of Regulatory Utility Commissioners ("NARUC"), the South Carolina Public Service Commission ("PSC") as well as the past and present policies of the Authority and the applicable provisions of contracts between the Authority and its customers.

Specific sources utilized and relied on herein include, but are not limited to, the Authority's current forecast of sales known as 2014 Load Forecast (LF1401) with adjustments for known and measurable changes, the forecast of fuel availability and cost, the results of the Authority's production costing analysis, the summarized analysis of the Authority's customer billing records, and the financial projections of Electric System operations, known as Financial Forecast 1501.

Structure of Report

This report provides for the development of revised retail rate and rate structures for the Authority. The basis for the revised rates is the projections of customer sales and usage characteristics as provided in Section 2. Section 3 develops the revenues required by the Authority for the Test Years 2016, 2017 and 2018. The cost of service analysis, which allocates the revenue requirements to the customer classes is described in Section 4 of this report. Section 5 presents the proposed rate structure changes by customer class. Section 6 provides the proposed rates and rate comparisons to existing rates. This report is supported by a series of appendices, which include a comparison of customer bill impacts due to the proposed rate changes (Appendix A – Bill Comparisons), the proposed rate schedules (Appendix B - Rate Schedules), and a technical appendix that includes specific schedules and tables from the Authority's cost of service analysis (Appendix C – Technical Appendix). Appendix C is not included as an attachment to this report, but is available upon request from the Authority. Across this report and the accompanying Appendices, number values provided in tables and text may not always sum or exactly match number values in other tables due to rounding in calculating and conveying this quantitative information.

Section 2
SALES FORECAST

General

The development of an accurate forecast of future power and energy requirements, sales, customers, and customer usage characteristics, is essential in the evaluation of the adequacy of electric rates and rate structures. This section summarizes the various factors considered and utilized in the development of the Authority's Electric System future power and energy requirements for the Test Years ending December 31, 2016, 2017 and 2018. Recognizing the importance of an accurate forecast, the Authority continually reviews and enhances its forecasting models to refine input data and assumptions and to reflect observed changes in customers, usage characteristics and industry trends.

Sales, customers, and customer usage characteristics for the Test Years were derived from an adjusted version of the 2014 Load Forecast (LF1401) and were utilized in the determination of the Authority's projected near term power and energy requirements. LF1401 was modified with an adjustment to Santee Cooper's system load based on updated assumptions and projections made by the Authority after the completion of LF1401. The adjusted 2014 Load Forecast was prepared by Santee Cooper, Central and a consulting firm, GDS Associates, Inc., ("GDS"). The forecast incorporates updates of the Authority's end-use/econometric models developed by GDS. In addition, the forecast reflects current economic outlooks for the Santee Cooper and Central service areas, projected retail price increases, and normal weather conditions. The forecast for the direct sale industrial customers reflects any additions and changes to existing contracts as well as known probable future changes. The forecast includes off-system sales and estimated demand and energy reductions from future energy efficiency programs to be implemented by Santee Cooper and Central.

Demand and Energy Requirements

The Authority provides retail electric service to residential, commercial, and industrial customers, and wholesale service to Central, other utilities, and the Municipal Customers made pursuant to various contracts that provide for the sale, and in some cases, exchange of large amounts of energy.

Each year, in consultation with Central, the Authority prepares and updates a Load Forecast that sets forth its projected demand and energy requirements, taking into account the projections of the Authority's Demand Side Management ("DSM") and Energy Efficiency ("EE") Programs, and its expected power supply resources necessary to meet its projections. The estimates of the power and energy requirements of the Authority for the Test Years 2016, 2017 and 2018 have been prepared based upon an analysis of customers and sales by class of service contained in the Load Forecast.

Projection of Electricity Sales to Ultimate Customers

The projections of electric energy sales are based on the results of econometric and end-use analyses of historical growth, usage patterns, appliance stock and efficiencies, housing characteristics, economic conditions, normalized weather, population statistics, and certain economic parameters such as the price of electricity and income. The demand and energy projections also reflect the estimated effects of the conservation and demand-side management programs that have been implemented, proposed, or contemplated.

Projected Demand

Table 2-1 below sets forth the projected 60-minute integrated peak demands including firm and non-firm demand, losses and the estimated effects of the various planned conservation programs:

Table 2-1
Projected Summer / Winter Demand by Customer Group

		2016 (MW)		2017 (MW)		2018 (MW)	
		Winter	Summer	Winter	Summer	Winter	Summer
1	Distribution	870	875	886	891	902	905
2	Distribution Losses	30	31	31	31	31	32
3	Total Distribution[(1)]	900	906	917	922	933	937
4	Industrial – Firm	158	158	158	158	158	158
5	Industrial – Non Firm[(2)]	387	387	387	387	387	387
6	Total Industrial	545	545	545	545	545	545
7	Wholesale[(3)]	3,478	2,951	3,371	2,848	3,268	2,742
8	Wheeling Service Deliveries	135	135	135	135	135	135
9	Total Transmission Deliveries	5,058	4,537	4,968	4,450	4,881	4,359
10	Transmission Losses	167	149	164	147	161	144
11	Total Territorial	5,225	4,686	5,132	4,597	5,042	4,503
12	Off-System Sales	174	305	184	317	194	330
13	Total Requirements	5,399	4,991	5,316	4,914	5,236	4,833

(1) Includes Residential, Commercial and Lighting.
(2) Santee Cooper does not plan or build generation capacity to serve Interruptible, Economy Power, or Stand-by loads.
(3) Includes the portion of Central's load served directly by SEPA and excludes the portion of load served by another supplier.

Projected Energy Requirements

Included in the Load Forecast are losses and the projected effects on energy sales from existing and planned conservation programs. Table 2-2 below sets forth the projected energy requirements:

Table 2-2
Projected Energy by Customer Group

		2016 Energy (GWh)	2017 Energy (GWh)	2018 Energy (GWh)
1	Distribution	3,857	3,906	3,957
2	Distribution Losses	135	137	139
3	Total Distribution[1]	3,992	4,043	4,096
4	Industrial – Firm	1,276	1,276	1,276
5	Industrial – Non Firm[2]	2,810	2,816	2,816
6	Total Industrial	4,086	4,092	4,092
7	Wholesale[3]	15,564	15,099	14,658
8	Wheeling Service Deliveries	209	199	189
9	Total Transmission Deliveries	23,851	23,433	23,035
10	Transmission Losses	591	581	571
11	Total Territorial	24,442	24,014	23,606
12	Off-System Sales	1,046	1,071	1,100
13	Total Requirements	25,488	25,085	24,706

(1) Includes Residential, Commercial and Lighting.
(2) Santee Cooper does not plan or build generation capacity to serve Interruptible, Economy Power or Stand-by loads.
(3) Includes the portion of Central's load served directly by SEPA and excludes the portion of load served by another supplier.

DSM and Energy Efficiency Programs

Included in the projection of demand and energy requirements in the Load Forecast are estimated reductions associated with DSM and EE programs. DSM and EE programs benefit the Authority's distribution customer classes (and Central) by reducing their demand and energy. The reduction in demand results in a lower relative contribution to the demand measured at the time of the coincident peak, which effectively lowers their relative class contribution to fixed cost recovery (see Section 4). The reduction in demand can also result in lowered billing demand for a specific customer's monthly bill (depending on the customer type). The energy reduction is a direct reduction in energy consumption during the billing month, resulting in lower energy charges as well as lower fuel adjustment charges. Table 2-3 below summarizes the projected demand and energy reductions during the Test Years.

Table 2-3
Projected Demand and Energy Reductions

2016			2017			2018		
Winter (MW)	Summer (MW)	Energy (GWh)	Winter (MW)	Summer (MW)	Energy (GWh)	Winter (MW)	Summer (MW)	Energy (GWh)
15	13	112	25	22	128	36	31	144

Projected Average Number of Customers

As an integral part of its forecasting process, the Authority projects the average number of customers it expects to serve by major customer class. The projected average number of customers based on the load forecast and used as a basis for this Study are provided in Table 2-4 below.

Table 2-4
Projected Average Number of Customers by Customer Group

		2016 Customers	2017 Customers	2018 Customers
1	Residential	147,743	150,793	153,873
2	Commercial	20,223	20,654	21,056
3	Lighting	10,182	10,399	10,604
4	Total Distribution	178,148	181,846	185,533
5	Industrial (Firm)	27	27	27
6	Wholesale	3	3	3
7	Total Customers	178,178	181,876	185,563

Sales To and Purchases From Other Entities

The Authority has entered into interchange contracts with other electric utilities and power marketers providing for the purchase and sale of economy energy. It should be noted that economy energy purchases tend to reduce system fuel and energy costs, and these reductions are automatically passed on to the ultimate customer via the Fuel Adjustment Clause, which are integral components of the Electric Rate Tariffs. Additionally, any operating revenue derived from economy power or "off system" sales (or transmission services provided to others) is available to the Authority for the benefit of its customers through adjustment clauses or recognized as an offset to costs.

Summary Of Projected Demand and Energy Requirements

Table 2-5 below sets forth the projected summer and winter demands (adjusted for demand-side management programs) at the generation level, energy requirements and system load factors used in this Study:

Table 2-5
Projected Net Demand and Energy Requirements

		2016	2017	2018
	Annual 60-Minute Peak Demand[(1)]			
1	Winter - MW	5,399	5,316	5,236
2	Summer - MW	4,991	4,914	4,833
3	Annual Energy Requirements – GWh	25,488	25,085	24,706
4	Annual System Load Factor[(2)]	53.9%	53.9%	53.9%

(1) Includes the estimated reduction in sales associated with conservation/energy efficiency programs.
(2) Annual Energy Requirements divided by the product of 8,760 hours and the peak demand.

Power Supply

Power supply to meet the projected demand and energy requirements for the Test Years 2016, 2017 and 2018 has been assumed to consist of:

- The Authority's existing generation resources aggregating approximately 5,182 MW net summer capability;
- The purchase of capacity and energy from other utilities;
- The availability of SEPA capacity and energy for Central, the Municipal Customers and the Authority; and
- The generating reserve requirements imposed by SERC.

The expected sources of energy have been simulated by the Authority using its computerized economic dispatching model, which takes into account monthly loads, unit availability, maintenance schedules, heat rates, fuel costs, and system operating characteristics. Although in recent years the annual peak demand has occurred during the winter months, the Authority plans its system resources taking into consideration the summer peak period, which has longer durations of peak demands and has decreased capacity of its generating resources.

Customer Service Classes

In general, it is electric utility practice to classify customers and types of service into homogeneous customer groups. The Authority presently has the following electric rate classifications as provided in Table 2-6 below:

Table 2-6
Existing Rate Schedules (2015)

Type of Service	Existing Rate Schedule Rate Code	Existing Rate Schedule Schedule
Residential:		
Residential General Service	RG	RG-13
Residential Demand Service	RD	RD-13
Residential Good Cents (New) Standard Plus	R1	RN-13
Residential Good Cents (New) Standard	R2	RN-13
Residential Good Cents (Improved Home) Standard Plus	R3	RR-13
Residential Good Cents (Improved Home) Standard	R4	RR-13
Residential Time of Use	RT	RT-13
Residential Net Billing	RB	RB-14
Commercial:		
General Service Commercial	GA	GA-13
General Service Demand	GB	GB-13
Seasonal General Service	GV	GV-13
General Service Time of Use	GT	GT-13
Large General Service	GL	GL-13
Temporary Service	TP	TP-13
Transition Adjustment	TA	TA-14
Lighting:		
Traffic Signal Service	TL	TL-13
Municipal Street Lighting	MS	MS-13
Private Outdoor Lighting	OL	OL-13
Municipal Light and Power	ML	ML-13
Industrial:		
Large Light and Power	L	L-14
Curtailable Supplemental Power	SP	L-13-SP
Interruptible Service	I	L-13-I
Economy Power Service	EP	L-13-EP
Economy Power Optional Energy Charge	EP-O	L-14-EP-O
Standby Service	SB	L-13-SB
Demand Response Buy Back	DRB	L-13-DRB
Economic Development Service Rider	ED	L-13-ED-02
Economic Development Service Tiered Rider	ED-T	L-14-EDT
Other:		
Fuel Adjustment Clause	FAC	FAC-13
Demand Sales Adjustment Clause	DSC	DSC-13
Economic Development Sales Adjustment Clause	EDA	EDA-12
Pole Attachment	PA	PA-13

Historical and projected customer statistics by major rate classification are set forth in Appendix C (Technical Appendix, available upon request). The historical data shown has been derived from detailed operating, accounting and billing data provided by the Authority. The projected average annual number of customers and annual energy sales for the Test Years 2016, 2017 and 2018 have been developed from the Authority's Load Forecast, which incorporates the following considerations:

(i) Continuation of recent historical growth and usage characteristics;

(ii) Continuation of past, present, and projected conservation and demand-side management programs; and

(iii) Continuation of the existing regulatory structure in South Carolina.

Any departure from those assumptions could have a material adverse effect on energy sales and revenues.

The projected Test Year 2016 composition of the Authority's ultimate customers and associated energy sales by rate classification is provided in Table 2-7 below:

Table 2-7
Projected Customers and Energy Requirements by Direct Served Customer Group[1]

		Average Number of Customers	Percent of Total	Annual Gigawatt-Hour Sales	Percent of Total
1	Residential	147,743	82.91%	1,817	22.88%
2	Commercial	20,223	11.35%	1,969	24.79%
3	Lighting	10,182	5.71%	71	0.89%
4	Total Distribution	178,148	99.97%	3,857	48.56%
5	Industrial	48	0.03%	4,086	51.44%
6	Total Customers	178,196	100.00%	7,943	100.00%

(1) Direct served customers do not include the Municipal Customers or Central.

Billing Determinants

In order to determine the adequacy and estimated amount of revenues produced by the existing rates, the existing rates and surcharges were applied to the projected billing determinants. The projected billing determinants are based on the detailed load forecast and a special analysis of historical billing data (See Appendix C – Technical Appendix, available upon request).

Section 3
REVENUE REQUIREMENTS

General

The various components of costs associated with the operation, maintenance, financing of improvements, renewal and replacement of facilities, and assurance of the adequacy and continuity of reliable service to customers are generally referred to as the revenue requirements of a governmentally operated utility. The determination of the revenue requirements as they relate to the Electric System, consistent with the methods of other publicly owned utilities utilizing revenue bond financing, includes the various generalized cost components described below. The specific meanings of the components of cost are set forth in the Revenue Obligation Resolution.

Operation and Maintenance Expenses: These are ongoing operations and maintenance expenses, generally as defined in the FERC Uniform System of Accounts. These expenses are traditionally segregated into the following categories which relate to the several basic "functions" involved in supplying electricity to the ultimate consumer:

- Production Operation and Maintenance Expenses (including fuel expenses, purchased power expenses, and other power generation expenses);
- Transmission Operation and Maintenance Expenses;
- Distribution Operation and Maintenance Expenses;
- Customer Accounting Expenses;
- Sales Expenses;
- Customer Information Expenses; and
- Administrative and General Expenses.

Payment in Lieu of Taxes: As a public body, the Authority is not a taxable entity. Nevertheless, as a practical matter, the Authority is required to pay certain sums in lieu of taxes to certain local authorities and to the State. As with other types of utilities, these costs must ultimately be recovered through rates.

Debt Service: These costs consist of interest and principal payments on the Authority's debt. They are included in the cost of service on an accrual basis. The Authority's debt includes tax-exempt and taxable senior lien revenue bonds and short-term commercial paper. Investment income earned by the Authority on invested funds is used to offset annual debt service costs in the assessment of annual revenue requirements.

Lease Payments: These costs consist of payments required of the Authority under various leases, including both capital leases and operating leases. The facilities that the Authority leases include a hydroelectric generating facility and a number of transmission lines, substations, and other facilities.

Allowances for Working Capital, Equity, and Coverage: These categories consist of two cost components that provide equity funds and debt service coverage for the Authority. They are:

- An allowance for increases in working capital, which reflects the additional amounts needed each year to cover timing differences between the payment of expenses and the receipt of revenues from customers. Traditionally, this allowance has been set at one-eighth of the change in operation and maintenance expenses (excluding purchased power and nuclear fuel expenses) from the prior year.
- An allowance for capital improvements, in the form of the Capital Improvement Fund ("CIF") requirement, which provides a source of capital, other than borrowings, for renewals, replacements, and improvements to the Authority's system. The CIF requirement provides non-debt funding and thereby generates additional equity capital and debt service coverage, which helps to maintain the financial strength of the Authority (and fulfill its bond credit rating).

The CIF requirement the Authority has historically included in cost of service has been about 8.5 percent of gross revenue requirements each year. For this Study, the CIF requirement has been increased to 9.0 percent in order to improve the Authority's debt service coverage ratio. With this increase in CIF requirement, the Authority plans to transfer additional revenues to the CIF fund and use such funds to pay down debt during the same years the CIF allowance is increased. This allows the Authority to increase revenues while decreasing debt service, both of which improve the Authority's debt service coverage metrics. The net impact on rates from this change is anticipated to be minimal.

Total Annual Net Revenue Requirements: The total of the cost components described above less other income and other operating revenues is the total annual net revenue requirements and represents the amount of revenues required to be recovered through rates and charges to ultimate customers.

Future Test Year Revenue Requirements

Electric rates should be set at a level such that the revenues produced will be sufficient to meet near future revenue requirements. An important objective of a projected test year is to establish rates and rate levels that will also reflect the then current costs of providing service and market conditions. Thus, it is necessary to estimate or project various cost components over a reasonable period of time in order to determine the required rate levels. Projections must consider changes in operating practices, new facilities, expected changes in cost, and other factors that may affect the overall cost of operating and maintaining the utility system.

In keeping with the FERC use of a projected test period in establishing rates, a forward looking projected test period or Test Years has been utilized for the determination of the Electric System projected revenue requirements.

Basis for Test Years Revenue Requirements

It was determined that the revenue requirements for this 2015 Electric Rate Study would be predicated on the projected costs of the Electric System for the three fiscal years ending December 31, 2016, 2017 and 2018, designated as the Test Years. The Authority developed the approved 2015 Financial Forecast 1501 for the Electric System. The expenditures contained in the forecasted data were used as a baseline in the development of the projections of the annual revenue requirements for the Test Years.

The 2016, 2017 and 2018 expenditures contained in the Financial Forecast utilized as a baseline in development of the revenue requirements for the study period are provided in Table 3-1 below and summarized and discussed as follows:

Table 3-1
Expenditures in Financial Forecast 2016, 2017 and 2018
($000)

		2016	2017	2018
1	Fuel and Purchased Power	$896,493	$924,997	$928,717
2	Other Operation and Maintenance	419,525	425,155	435,302
3	Total Operation and Maintenance	1,316,018	1,350,152	1,364,019
4	Payment in Lieu of Taxes	24,650	25,620	26,181
5	Debt Service and Lease Payments	437,038	468,260	482,245
6	Working Capital	0	4,074	2,311
7	CIF Payment	175,817	182,780	185,415
8	Gross Revenue Requirement	$1,953,523	$2,030,886	$2,060,171

Assumptions and Considerations

The development of the projected revenue requirements for the Test Years ending December 31, 2016, 2017 and 2018 required certain assumptions and considerations in order to reflect certain known or anticipated changes. The analyses, estimates and projections summarized herein have been based upon an understanding of certain contracts, agreements, regulations, statutory requirements and planned operations. In the preparation of this report, certain assumptions have been made with respect to conditions which may occur in the future. While these assumptions are reasonable for the preparation of this Study, they are dependent upon future events and actual conditions may differ from those assumed. To the extent that actual future conditions differ from those assumed herein or provided to us by others, the actual results will vary from those projected.

The major assumptions and considerations included in the development of the projected annual revenue requirements have been divided into two categories and are listed below:

General

1. The general economic activity experienced in recent years will continue and inflation will remain at existing levels of approximately 3.0 percent annually.
2. All applicable Federal and State environmental laws will continue to be implemented, applied and enforced.
3. There will be no material change in the taxation of fuel used to produce electricity.
4. There will be no material change on the taxation of governmentally-owned or municipally financed electric generation, transmission and distribution systems.
5. There will be no material change in the level of Federal, State or local regulation of governmentally-owned electric systems.
6. There will be no material change in the Authority's existing ability to import or export power over the statewide transmission grid.
7. The existing form of governance and policies established by the Authority will continue throughout the study period.
8. The Authority will continue to be the exclusive owner and operator of the Electric System, including its generation, transmission, distribution, and customer care facilities.

Specific

1. Demand and Energy Requirements

The Load Forecast 1401 (LF1401) was the basis for the development of the projected energy and demand requirements for the fiscal years ending December 31, 2016, 2017 and 2018. It should be noted that (a) any meaningful variances in the load characteristics of existing or new customers, and/or (b) any differences in expected initiation of service for anticipated new customers, and/or (c) differences in the expected effectiveness of the various conservation programs initiated and contemplated by the Electric System and/or (d) any changes in Federal or State legislation that permit customers to select their energy service provider may result in a distortion and/or an over or under recovery of revenue requirements for 2016, 2017 and 2018. The LF1401 includes the continuation of moving approximately 1,000 MW of load currently served by Central off of the Authority's system by 2019. LF1401 was also adjusted to increase the amount of assumed distribution losses, and includes an opportunity sale to a new municipal customer beginning

July 1, 2015. Load assumptions also reflect the termination of Century's power sales contract effective December 31, 2015.

2. Operation and Maintenance Expenses.

The non-fuel O&M expenses for 2016 through 2018 were approved by the Board of Directors on December 8, 2014. The approved expenses included approval of the Authority's use of a different method for determining fixed and variable costs from that typically employed under FERC Predominance, which better aligns cost classifications with actual O&M expenditures.

3. Power Costs

Electric System costs are based on an economic dispatch of Santee Cooper's generating resources, including purchases. The dispatch reflects Santee Cooper's coal contracts, assumed purchased power contracts, and scheduled maintenance. Fuel burned is determined using average heat rate curves.

Power supply costs used herein are predicated in part on (a) the availability of the Electric System's existing generating resources, (b) the purchase of long term capacity and attendant energy, (c) generation reserve levels being maintained at current levels, and (d) the acquisition of all necessary permits and licenses to continue to operate the existing generating resources and transmission facilities and the planned generating resource at each facility's design capabilities.

Fuel and purchased power energy costs reflect any existing long-term contracts and their applicable annual escalation indexes and productivity adjustments as well as market purchases. Gas commodity prices are projected from a Santee Cooper internal forecast based on market-forward prices. Nuclear fuel prices for 2016, 2017 and 2018 were based on actual costs to Santee Cooper and thereafter based on projections from SCE&G. These projections do not include any costs associated with potential carbon legislation.

Projected purchased power capacity costs include renewable purchases, spot market purchases, short-term energy transactions and firm purchased power costs assumed to be contracted to meet projected power requirements during the forecast period.

4. Capital

For the purposes of this report as included in the financial projections, Commercial Operation Date ("COD") for Summer Nuclear Unit 2 is projected to be September 2019 and COD for Summer Nuclear Unit 3 is projected to be September 2020.

Future generation construction expenditures for Summer Nuclear Units 2 & 3 in Jenkinsville, South Carolina currently include expenditures for a 45 percent ownership share of the units, reducing in accordance with the agreement with SCE&G on the closing dates of the sale of 5 percent ownership interest in the units.

A portion of the interest expense incurred for Santee Cooper's retained ownership share in V. C. Summer Units 2 & 3 for the test year period has been capitalized. The remainder of the retained portion is expensed and included in rates.

Future generation expenditures also include renewable generation resources.

Unrecovered costs associated with the cancelled Pee Dee Project are recovered through rates at the amount of approximately $9.2 million annually over the test year period.

5. Financing Considerations

Table 3-2 below provides interest rates which were assumed for the various types of debt financing:

Table 3-2
Interest Rates Assumed for Debt Financing

		2016	2017-2018
1	Taxable Commercial Paper/Bond Anticipation Notes	2.25%	3.50%
2	Tax-Exempt Commercial Paper / Bond Anticipation Notes / Float Rate Notes	1.75%	2.50%
3	Taxable Revenue Obligation Bonds (30 year)	7.75%	8.80%
4	Taxable Revenue Obligation Bonds (40-year)	8.10%	9.15%
5	Tax-Exempt Revenue Obligation Bonds (30-year)	5.85%	6.90%
6	Tax-Exempt Revenue Obligation Bonds (40-year)	6.20%	7.25%

The Board of Directors has authorized the issuance of variable rate debt not to exceed 20 percent of the aggregate Authority debt outstanding (including commercial paper notes) at the end of each fiscal year. The financial projections reflect debt service (principal and interest) for existing and future debt issuances.

6. Payment to the State

Payment to the State of South Carolina is based on 1 percent of projected operating revenues (on an accrual basis).

No assumption or provision has been made or included in the projections utilized in the 2015 Electric Rate Study to reflect unforeseen load changes or changes in customer consumption characteristics which may be the result of, but not limited to, deviations from normal weather conditions, or modifications to or limitations on existing generation or transmission facilities, generating station or unit failures, or other catastrophic events.

It has been assumed that the Authority will continue to operate and exclusively serve all customers in its assigned service territory. No assumptions have been made to recognize the effects associated with the potential (a) restructuring of the electric utility industry in the state to enable, among other things, customers to choose supplier, (b) unbundling of traditional services and rates, (c) recovery of stranded investment costs, if any, (d) sale of all or a portion of the Electric System (unless otherwise noted herein), and (e) the passage of federal legislation that would impair the Authority's ability to issue indebtedness.

It should be recognized that in the development of the projected near term revenue requirements, there are several assumptions that have a material impact on the level of costs to be recovered in 2016, 2017, 2018 and beyond. These assumptions include: (i) the construction and financing costs of Summer Nuclear Unit 2 and Unit 3, (ii) the eventual sale of equipment associated with the cancelled generating station at Pee Dee and, (iii) the termination of Century as a customer receiving and paying for service similar to that under its existing contract.

Should these assumptions not materialize or become significantly delayed or revised, the level of the proposed rate increases in 2016 and beyond may differ from those forecasted in this Study.

7. Timing of Rate Adjustments and Calculation of Revenue Requirement

Because annual revenue requirements are calculated on the basis of calendar years and rate adjustments are not effective until April of each calendar year, Santee Cooper adjusted proposed rates to account for such a lag in revenue collection. To meet the forecast revenue requirements in 2016, 2017 and 2018, the entire shortfall in revenues caused by the timing lag in revenue recovery was averaged over two years. This two-year shortfall was added to the revenue requirements of 2016 and 2017, and proposed rates in those years were adjusted to recover the adjusted revenue requirement. This allows the Authority to leave 2018 rates unaffected by the impacts of the timing lag on revenue recovery, which will better position the Authority to reevaluate rates and forecast revenues after the completion of the three-year succession of rate adjustments as proposed herein.

Revenue Requirements for the Test Years 2016, 2017 and 2018

The revenue requirements of fiscal years ending December 31, 2016, 2017 and 2018 have been developed using the Financial Forecast 1501 values as a base. Predicated on the hereinbefore discussed assumptions and considerations, the Electric System retail revenue requirements for the Test Years 2016, 2017 and 2018 are summarized in Table 3-3 as follows:

Table 3-3
Projected Net Revenue Requirements Summary($000)

		2016	2017	2018
1	Operating Expenses	$1,316,018	$1,350,152	$1,364,019
2	Other Revenue Requirements	637,505	680,734	696,153
3	*Gross Revenue Requirements*	1,953,523	2,030,886	2,060,171
	Projected Revenue:			
4	Off System & Non-Class Sales	246,071	260,374	271,312
5	Other Operating Revenues	15,783	16,585	17,375
6	Interest and Miscellaneous Inc.	10,225	20,883	17,667
7	Wholesale	1,177,410	1,208,765	1,213,137
8	Total Projected Revenue	1,449,489	1,506,607	1,519,491
9	Total Cost of Service	504,035	524,279	540,681
10	Existing Rate Revenues	472,487	485,542	492,344
11	(Deficiency) under Existing Rates	($31,548)	($38,737)	($48,337)
12	Percent of Existing Rate Revenues	-6.7%	-8.0%	-9.8%

To the extent electric rates are increased as proposed herein effective April 1, 2016, April 1, 2017, and April 1, 2018, the deficiencies are projected to be eliminated.

Treatment of Wholesale Revenue

A large portion of Santee Cooper's load is delivered to Central, which purchases wholesale power from the Authority under a confidential negotiated contract. Since the 2012 rate study, Central's contract was renegotiated, and as such, the manner in which Central's revenues and costs flow through the cost of service model were evaluated as part of this Study given the new specifics of the contract. The cost allocation methodology used in accordance with Central's contract is similar but different from that used by Santee Cooper with its retail customers.

In Leidos' opinion, allocating costs to wholesale and retail customers in a similar but different manner is an acceptable industry practice. Santee Cooper applied revenues resulting from on-system wholesale contract sales as a credit on a functional basis to the gross revenue requirement of the retail classes. This approach reduced the revenue requirement for each function as applied to the retail class. Subsequently, the functionalized net revenue requirement was allocated to the Authority's retail customers in a manner similar to the 2012 Electric Rate Study and as described herein.

In addition to on-system wholesale revenues, the Authority also makes sales to municipal wholesale customers that are off-system. Such revenues are allocated to the Authority's retail customers as a credit to cost of service, and to the extent that such revenues are not included in base rates, will be distributed to the retail classes through the Demand Sales Adjustment.

Section 4
COST OF SERVICE ANALYSIS

General

In allocating utility costs, there are three major processes: functionalization, classification, and allocation. The functionalization and classification of the revenue requirements of the Test Years are discussed in the first part of this section. The development of allocation factors for the Test Years revenue requirements is discussed and set forth in the second half of this section.

Functionalization of Test Years Expenditures

Although budgeting and accounting systems generally follow functional groups, i.e., production, transmission, etc., certain costs such as those associated with administrative and general expenses and debt service generally are not assigned by accounting and budgetary convention to a major function. A cost of service analysis usually requires the rearrangement of certain expenditures into functional groups (i) to be more representative of the expenditure causation, (ii) to combine costs that have been incurred for a similar purpose, and (iii) to facilitate the allocation of cost responsibility. Thus, the functionalization of certain costs is merely a ratemaking mechanism to apportion such costs to the common utility function.

Categorization of costs in terms of several basic “functions” involved in the supply of electricity to the consumer is embodied to a large degree in the FERC Uniform System of Accounts:

- Production (the generation of electricity or its purchase at wholesale);
- Transmission (the operation of a high-voltage system-wide grid or network for the interconnection of generating facilities and major load centers);
- Distribution (the local distribution of electricity, generally at lower than transmission voltages, within and around load centers, to ultimate customers); and
- Customer Service (including a variety of customer service, billing, and administrative activities).

The typical functions of the Test Years Retail Revenue Requirements are developed in the retail cost of service analysis and summarized in Table 4-1 below.

Table 4-1
Functionalization of Test Years Retail Revenue Requirements ($000)

	2016	2017	2018
Production - Those costs associated with generating and purchasing power and delivering that power to the utility's bulk transmission system.	$389,686	$411,181	$416,249
Transmission - Those costs incurred in connection with the delivery of power over the bulk transmission system to the primary and secondary distribution system.	19,272	19,613	29,800
Distribution - Those costs incurred in connection with the delivery of power through the primary and secondary distribution system to the utility's consumers.	53,822	52,658	52,778
Customer and Sales Expense - Those costs incurred for billing accounts and providing various services and information for its customers.	41,254	40,826	41,852
TOTAL FUNCTIONALIZED REVENUE REQUIREMENTS	$504,034	$524,278	$540,679

Classification of Various Costs

Cost of service classification provides the means to distribute test year revenue requirements to the various customer classes. The classification of costs described below reflects usual regulatory practice as well as a reasonable and equitable approach.

Demand (Fixed) Costs: Defined as those costs incurred to maintain in readiness-to-serve an electric system capable of meeting the total combined demands of all classes of customers. Demand costs are those costs that are generally fixed in the short-run, that do not materially vary directly with the number of kilowatt-hours ("kWh") generated or sold, and that are not defined as customer costs. Demand costs will include that portion of operation and maintenance expenses, debt service, renewals, replacements and improvements, and other costs which are not designated as specifically customer or variable energy costs.

Energy (Variable) Costs: Defined as those costs that vary substantially or directly with the amount of energy sold or generated and purchased, including such items as fuel and a portion of operation and maintenance expense for production facilities.

Customer Costs: Defined as those costs directly related to the number, type and size of customers, such as customer accounting and collecting, the costs of meters and services, and other distribution-related costs associated with maintaining the minimum distribution system to serve the Authority's customers.

Operation and Maintenance Expenses

Presented below is a description of how the Authority's functionalized Test Years revenue requirements were classified for purposes of the cost of service analysis.

Production Expenses

Fuel expenses represent the largest single operation and maintenance expenditure of the Authority and are, for the most part, classified as energy-related because they vary in direct proportion to energy usage. However, a portion of fuel expenses is incurred in startup and to keep certain generating units running at less than full load in order to provide "spinning reserves" (capacity of generating units that are on-line and operating, but which are not fully loaded so that they may meet anticipated changes in demand and other contingencies). These fuel expenses, therefore, are classified as demand-related because they do not vary directly in proportion to energy consumption. Historically, the Authority has estimated the demand-related fuel expenses as 5 percent of total fuel costs. This percentage is used for purposes of the current study as well. Other production expenses (i.e., expenses other than fuel and purchased power) are classified based on an account-by-account analysis of the nature of the costs involved which differs slightly from that typically employed under FERC Predominance. This system better aligns cost classifications with actual O&M expenditures. Specifics on the Authority's classification of such expenses is provided in detail in Appendix C (Technical Appendix).

Transmission Expenses

Transmission operation and maintenance expenses are classified 100 percent as demand-related because (i) a given transmission system is sized to transmit the load (or demand) placed on that system; and (ii) the expenses incurred to operate and maintain the system do not vary with energy usage.

Distribution Expenses

Distribution expenses represent a combination of costs related to the demand, customer, and direct assignment classifications. The classification of the Authority's distribution expenses is based on an account-by-account analysis of the Authority's historical expenses. In general, meter expenses, customer installation expenses, and certain maintenance expenses are classified as customer-related, while load dispatching, station expenses, and line expenses are classified as demand-related. Expenses identified as being directly related to providing services to a particular customer or customer class have been directly assigned to that customer or customer class.

Customer Accounts, Service and Informational Expenses, and Sales Expense

Customer accounts, service and informational expenses, and sales expenses by definition, are all classified as customer-related because they represent costs incurred by the Authority for billing accounts and providing various services and information for its customers. These costs are based on the FERC Uniform System of Accounts.

Administrative and General Expenses

Administrative and general expenses are principally related to personnel matters. Property insurance costs are the one category of administrative and general expenses that are not personnel related. Accordingly, property insurance costs are functionalized and classified on the basis of insured property, while all other administrative and general expenses are functionalized and classified on the basis of functionalized wages and salaries.

Payments in Lieu of Taxes

This cost item generally includes franchise taxes, payments to the State, energy sales tax and generation tax, and other sums in lieu of taxes. Except for a small portion of franchise taxes directly assigned to distribution customers, the Authority's payments in lieu of taxes are classified as demand-related because they are regarded as fixed costs related to system facilities.

Debt Service, Capital Improvements Fund Requirements, and Lease Payments

The Authority's two primary sources of funding additions, renewals, replacements, and improvements to the Authority's system are through the issuance of debt and the CIF requirements.

The Authority's debt service payments are incurred as a result of infrastructure additions to the system and are, therefore, allocated in the same manner as the Authority's facilities. The Authority's plant in service is first functionalized, and then classified to various cost categories. The resulting classification of plant is used to classify debt service payments to demand-, energy-, or customer-related components. The Authority's CIF requirement is computed as 9.0 percent of gross revenue requirements. Because the CIF is used in lieu of debt to fund capital improvements, it is allocated in the same manner as the Authority's facilities are allocated.

Lease payments are related to certain of the Authority's transmission and generation facilities and are classified as demand-related.

Working Capital

The Authority's working capital requirements, which are directly related to operating expenses, are classified to the demand-, energy-, and customer-related components based on the classification of total operation and maintenance expenses other than nuclear fuel and purchased power expenses.

Other Income and Revenues

Other income and operating revenues, such as revenues from invested funds, non-class sales, wheeling, sales of property, and forfeited discounts, among others, are classified as being either demand-, energy-, or customer-related based on an analysis of the particular source of such revenues.

Development of Customer Class Allocation Factors

This section discusses the development of the factors utilized to allocate the demand-, energy-, customer-, and other-related costs to the various customer classes. The aforementioned costs are allocated to the customer classes according to the cost allocation factor developed for each class and for each type of cost.

The development of the allocation factors requires a compilation of data from several different sources including, among others, the Authority's peak demand and energy forecasts, historical billing and other customer information, and data from the Authority's on-going load research program. Cost of service allocation factors are developed based on the usage characteristics of the Authority's firm requirements customer and do not take into account non-firm sales. Following is a brief discussion of each type of allocation factor used in this Study.

Demand Allocation Factors

Demand allocation factors are used to allocate that portion of revenue requirements which have been determined to be demand- (or capacity) related. Costs allocated based on the demand allocation factors include:

- Demand-related production expenses;
- Demand-related purchased power expenses;
- Transmission expenses;
- Demand-related distribution expenses;
- Demand-related debt service requirements; and
- Capital Improvements.

The demand allocation factors were developed based on historical demand and energy relationships determined by the Authority's Load Research Program. The demand allocation factors are based on the estimated annual coincident and non-coincident peak demands (the allocation factors are referred to as Coincident Peak or CP and non-coincident peak or NCP, respectively). Certain costs, such as most production related costs, are related to the maximum system coincident peak demand, while other costs, such as most distribution related costs, correspond to the maximum non-coincident demand for a particular load.

In the Load Research Program, the Authority develops a sample list of load survey meters. This list contains customers by rate code and strata with at least one year of data, and it is sorted by average annual consumption. From the sample list, load survey meters are selected equally and randomly from each range. Meters are not placed based on dwelling type or customer type. The Load Research Program takes the strata data and inputs those parameters into a system to analyze rates by class, strata, and load survey meter. Each month the actual billing data by class is input into the program and the established weightings from the strata data are applied to produce totalized hourly coincident and non-coincident load data by rate code. The results of the load research showed a range of variations in the load factors by rate code. When prudent, these variations were then limited in range to be within a fixed percentage of the larger rate code classes, that is, rate code RG for the residential classes and GA and GB for the commercial classes. These limitations allow for the variations in load factor by rate code, but prevents a particular rate code from having an unreasonable rate change, thereby preventing large impacts on energy sales and revenues.

Demand allocation factors for production costs were developed based on the four coincident peaks during the months of January, July, August, and December ("4CP") which was the allocation method chosen based on the Authority's load characteristics for this Study. The Authority's system has two distinct periods with very little difference in peak load among the summer months and among the winter months. While the actual annual peak has typically occurred during the winter months for several years, due to the duration of the peaks, the reduced rated capacity for generation units, and the limited access to purchased power in the summer months, the Authority plans for capacity resources to meet the summer peaks.

To further allocate production costs among the residential, commercial and lighting classes, a blend of average and excess and a modified 4CP method was used. The modified 4CP approach incorporates 1NCP to allocate some production costs to off-peak loads. The proposed approach reduces the contribution of the "average and excess" method to 20 percent of the allocation, and the "modified 4CP" method to 80 percent of the allocation. This is a continuation of the transition that began in the 2009 Rate Study towards an eventual phase out the contribution of the "average and excess" method.

Demand allocation factors for transmission costs were developed based on the average of the twelve monthly coincident peaks ("12CP"). This is congruent with industry standards and is the preferred method by FERC in developing open access transmission tariff ("OATT").

Demand allocation factors for distribution costs including line expenses, substation expenses and load dispatching expenses were developed based on the average NCP of each rate class. All demand allocation factors include, where appropriate, transmission and distribution losses.

The following Tables 4-3, 4-4 and 4-5 summarize the demand allocation factors for the Test Years.

Table 4-3
Summary of Demand Allocation Factors

	Customer Class	2016 Production 4 CP (MW)	Production 4 CP (%)	Transmission 12 CP (MW)	Transmission 12 CP (%)	Distribution NCP (MW)	Distribution NCP (%)
1	Residential	481,905	47.07%	407,761	45.98%	424,822	49.55%
2	Commercial	387,031	37.80%	327,406	36.92%	418,645	48.83%
3	Lighting	11,690	1.14%	8,445	0.95%	13,818	1.61%
4	Total Distribution	880,626(1)	86.01%	743,612(2)	83.85%	857,285	100.00%
5	Industrial	143,204	13.99%	143,204	16.15%		
6	Total	1,023,830	100.00%	886,816	100.00%		

(1) Represents a "modified 4 CP" using a blend of average and excess demands.
(2) Represents a "modified 12 CP" using a blend of average and excess demands.

Table 4-4
Summary of Demand Allocation Factors

	Customer Class	2017 Production 4 CP (MW)	Production 4 CP (%)	Transmission 12 CP (MW)	Transmission 12 CP (%)	Distribution NCP (MW)	Distribution NCP (%)
1	Residential	492,082	47.35%	416,125	46.27%	433,896	49.78%
2	Commercial	392,034	37.72%	331,441	36.85%	423,603	48.60%
3	Lighting	11,922	1.15%	8,599	0.96%	14,106	1.62%
4	Total Distribution	896,038(1)	86.22%	756,165(2)	84.08%	871,605	100.00%
5	Industrial	143,204	13.78%	143,204	15.92%		
6	Total	1,039,242	100.00%	899,369	100.00%		

(1) Represents a "modified 4 CP" using a blend of average and excess demands.
(2) Represents a "modified 12 CP" using a blend of average and excess demands.

Table 4-5
Summary of Demand Allocation Factors

	Customer Class	Production 4 CP (MW) 2018	Production 4 CP (%) 2018	Transmission 12 CP (MW) 2018	Transmission 12 CP (%) 2018	Distribution NCP (MW) 2018	Distribution NCP (%) 2018
1	Residential	502,401	47.65%	424,575	46.57%	442,993	50.03%
2	Commercial	396,615	37.62%	335,096	36.76%	428,145	48.35%
3	Lighting	12,149	1.15%	8,750	0.96%	14,395	1.63%
4	Total Distribution	911,165(1)	86.42%	768,421(2)	84.29%	885,533	100.00%
5	Industrial	143,204	13.58%	143,204	15.71%		
6	Total	1,054,369	100.00%	911,625	100.00%		

(1) Represents a "modified 4 CP" using a blend of average and excess demands.
(2) Represents a "modified 12 CP" using a blend of average and excess demands.

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those revenue requirements classified as variable or energy-related and assumed to vary directly with the level of energy sales or generation. The costs classified herein as variable or energy related include fuel expense, the energy-related portion of purchased power expenses, and the variable portion of other production expenses. The development of the energy allocation factors involves a ratio analysis of total energy consumption for the individual customer class as compared to total system energy requirements, both measured at the production (or generation) level, so as to include transmission and distribution losses, as appropriate.

The projected Test Years energy sales data is discussed in Section 2. The resulting energy allocation factors are shown in Table 4-6 below.

Table 4-6
Summary of Energy Allocation Factors

	Customer Class	2016 (GWh)	2016 (%)	2017 (GWh)	2017 (%)	2018 (GWh)	2018 (%)
1	Residential	1,927	35.69%	1,963	36.01%	2,005	36.41%
2	Commercial	2,089	38.69%	2,105	38.61%	2,117	38.44%
3	Lighting	76	1.41%	76	1.39%	77	1.40%
	Total Distribution	4,091	75.78%	4,144	76.01%	4,199	76.25%
4	Industrial	1,308	24.22%	1,308	23.99%	1,308	23.75%
5	Total	5,400	100.00%	5,452	100.00%	5,507	100.00%

Customer Allocation Factors

The factors used to allocate customer-related revenue requirements are based on the projected average number of customers or delivery point, and/or service attachments in each customer classification. Customer-related revenue requirements include meter reading, meter maintenance, customer installations, billing, collecting, and other customer related accounting, service, and information functions.

In apportioning customer related costs and revenues to the various customer classifications, customer allocation factors were utilized that recognized weighted and un-weighted customers and fixtures. The customer weighting factors were based on an analysis of the Authority's customer related costs. The customer allocation factors are shown in Table 4-7 below.

Table 4-7
Summary of Customer Allocation Factors (2016)

Customer Class	Rate	Customers or Delivery Points (Avg. 2016-2018)	(%)	Weight Factor	Weighted Customer	(%)
1 Residential	RG,R1, R2,R3, R4	150,803	82.9%	1.00	150,803	80.8%
2 Commercial Non-Demand	GA,TP	18,132	10.0%	1.30	23,571	12.6%
3 Commercial Non-Demand	TA	137	0.1%	2.09	287	0.2%
4 Commercial Demand	GB,GV	2,108	1.2%	2.09	4,406	2.4%
5 Commercial Lg Demand	GL	43	0.0%	2.09	89	0.0%
6 Commercial Time of Use	GT	15	0.0%	2.09	30	0.0%
7 Commercial Traffic Light	TL	210	0.1%	1.00	210	0.1%
8 Lighting	MS,OL	10,395	5.7%	0.50	5,198	2.8%
9 Total Distribution		181,843	100%		184,594	99.0%
10 Industrial (Firm)		27	0.0%	40.51	1,094	0.6%
11 Total Retail System		181,870	100%		185,688	100%

Other Allocation Factors

Administrative and general expenses are allocated based on wages and salaries expense, with the exception of property insurance which is allocated based on net plant in service.

Debt service payments are related to the existing plant and additions of utility plant on the Authority's system. Therefore, debt service is functionalized on the basis of net plant in service and allocated using the appropriate plant allocation factor.

Direct Assignment

Sales Expenses are directly assigned to the various customer classes based on the specific services provided and the customer classes receiving such service. The Sales Expenses allocation factors are shown in Table 4-8.

Table 4-8
Summary of Sales Expense Allocation Factors

		2016		2017		2018	
	Customer Class	($000)	(%)	($000)	(%)	($000)	(%)
1	Residential	$4,792	31.72%	$4,630	31.73%	$4,872	31.74%
2	Commercial	5,561	36.81%	5,372	36.81%	5,650	36.80%
3	Lighting	0	0.00%	0	0.00%	0	0.00%
4	Total Distribution	10,352	68.53%	10,002	68.54%	10,522	68.54%
5	Industrial	4,754	31.47%	4,592	31.46%	4,830	31.46%
6	Total	$15,106	100.00%	$14,594	100.00%	$15,352	100.00%

DSM and EE costs are assigned directly to Residential and Commercial classes and are allocated to the customer classes on the basis of the projected demand and energy savings of each of the classes.

Allocated Cost of Service

As one of the factors considered in the development of the proposed rate levels and rate structures included in this Study, certain analyses common in ratemaking have been employed which provide a reasonable indication of the revenue levels required to recover the full cost of service or revenue requirement of each customer class. Since it is not the practice in utility accounting to maintain a subdivision of accounts that will report the cost of rendering service to each customer class, an allocation of costs must be made on the basis of parameters predicated upon the available classifications of operating expense and utility plant. The allocated cost of service starts with the projected revenue requirements for the Test Years and allocates these requirements to the various customer classes based on the allocation factors discussed above.

Load At Risk Analysis

Santee Cooper maintains diligence in seeking to provide competitive rates to its customers. Additionally, large firm industrial customers are important sales for Santee Cooper as such sales benefit all participants in the Authority's system. As part of this Study, the Authority maintained attention to offering competitive rates to such large firm industrial customers as a result of the system costs being allocated to the retail class.

Given the initial results of the retail cost of service, Santee Cooper analyzed the calculated required revenue increases from the perspective of competitiveness. The Authority reviewed data collected during the economic downturn in 2008-2009 to understand how load may decrease during periods of economic hardship. This analysis determined a portion of the Authority's load that may be considered "at risk" of leaving the system. Losing such load is not in the best interest of any of Santee Cooper's customers as such load loss would result in more fixed costs that must be recovered from remaining customers. Consequently, a portion of costs originally allocated to such large industrial firm customers was shifted away from the customer class to maintain competitive industrial rates, encourage economic development, and support load retention, all of which would mitigate price increases to the remaining system and ultimately benefit all of the Authority's customers.

Summary of Results

The results of the cost of service analysis are summarized in Table 4-9 as follows:

Table 4-9
Summary of Allocated Cost of Service
($000)

	Customer Class	2016	2017	2018
1	Residential	$216,305	$226,141	$235,005
2	Commercial	192,634	200,308	205,557
3	Lighting	11,895	12,054	12,394
4	Total Distribution	420,834	438,503	452,956
5	Industrial	83,199	85,776	87,723
6	Total	$504,033	$524,279	$540,679

Comparison of Allocated Costs to Existing Rate Revenues

The allocated costs by rate class compared to the revenues by class assuming the existing rates are in effect is provided in Tables 4-10, 4-11 and 4-12 as follows.

Table 4-10
Comparison of Allocated Costs to Existing Firm Rate Revenues (2016)

	Customer Class	Costs ($000)	Revenues ($000)	Difference ($000)	(%)
1	Residential	$216,305	$202,087	$14,218	7.0%
2	Commercial	192,634	179,682	12,952	7.2%
3	Lighting	11,895	10,952	943	8.6%
4	Total Distribution	420,834	392,721	28,113	7.2%
5	Industrial	83,199	79,766	3,433	4.3%
6	**Total**	$504,033	$472,487	$31,546	6.7%

Table 4-11
Comparison of Allocated Costs to Existing Firm Rate Revenues (2017)

	Customer Class	Costs ($000)	Revenues ($000)	Difference ($000)	(%)
1	Residential	$226,141	$208,502	$17,639	8.5%
2	Commercial	200,308	184,491	15,817	8.6%
3	Lighting	12,054	11,128	926	8.3%
4	Total Distribution	438,503	404,121	34,382	8.5%
5	Industrial	85,776	81,421	4,355	5.3%
6	**Total**	$524,279	$485,542	$38,737	8.0%

Table 4-12
Comparison of Allocated Costs to Existing Firm Rate Revenues (2018)

	Customer Class	Costs ($000)	Revenues ($000)	Difference ($000)	(%)
1	Residential	$235,005	$213,141	$21,864	10.3%
2	Commercial	205,557	186,259	19,298	10.4%
3	Lighting	12,394	11,198	1,196	10.7%
4	Total Distribution	452,956	410,598	42,358	10.3%
5	Industrial	87,723	81,746	5,977	7.3%
6	**Total**	$540,679	$492,344	$48,335	9.8%

The detailed cost of service analysis, along with supporting tables, is shown in the Appendix C (Technical Appendix) available upon request from the Authority.

Section 5
RATE DESIGN

General Rate Design Criteria

Rate design is the culmination of a rate study whereby the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the system will be recovered in an equitable manner consistent with the results of the allocated cost of service study, utility policy objectives, and any applicable orders and/or requirements of local, state, and federal regulatory authorities. To the extent possible, rate design should consider and reflect overall revenue stability, consistency with historical rate forms, conservation considerations, competitiveness with neighboring utility systems, and the policies of those charged with the management and operation of the utility.

The proposed rate levels and rate structures developed and submitted to the Authority for consideration and adoption should continue to meet the following electric utility rate criteria for service provided by publicly owned utilities:

- Electric rates should be based on a rate policy which calls for the lowest reasonable prices consistent with the customer requirements for quality service that is efficiently rendered.
- Electric rates should support economic development, job attraction and retention.
- Electric rates should be simple and understandable.
- Electric rates should be equitable among classes of customers and individuals within classes, taking into consideration the cost to provide service.
- Electric rates should avoid undue price fluctuations.
- Electric rates should be designed to encourage the most efficient use of the utility plant and discourage unnecessary or wasteful use of service.
- Electric rates should comply with applicable orders and requirements of local, state and federal regulatory authorities that have jurisdiction.

Proposed Rates

Changes to the existing rate structures/design are summarized below, and the proposed rates necessary to recover the revenue requirements are provided in detail in Appendix A (Bill Comparisons) and Appendix B (Proposed Rate Schedules).

Proposed Residential Rate Designs

General

Unless otherwise noted below, the existing rate structures for the residential rates are proposed to remain the same, including the use of a customer charge and seasonal energy charges. Across all residential rates, the Authority is proposing an increase to the monthly customer charge to better recover fixed costs, and an increase to the energy price differential between summer and non-summer months. The change to the energy price differential is being proposed to better incentivize efficient use of the Authority's system. Additional proposed changes to the existing residential rates include:

- Migration of all customers on the RR and RN rates to a transitional schedule (R-TA-16).
- Elimination of the Net Billing Rate (RB-14).
- Elimination of the Residential Demand Service Rider (RD-13) and Amendments to the Residential Time-of-Use Rate (RT-13).

Transition of RR and RN Rates (Good Cents) to RG Rate

Santee Cooper has created a new transitional schedule (R-TA-16), which will transition all RR and RN customers to the Residential General Service rate (RG). The transition process is dictated by a schedule of credits applied to both the customer charge and energy charge portion of RR and RN customers' bills. The size of the credit to each portion of the bill will gradually reduce to zero by 2018, which will complete such customers' transition to the RG rate. The Authority is also proposing that the "Good Cents" branding for customers on the RR and RN rate be eliminated during the process of transitioning such customers to the RG rate.

Elimination of the Residential Net Billing Rate (RB-13)

Santee Cooper has proposed a distributed generation ("DG") rate rider that stipulates the rate and terms and conditions that apply to customers that choose to install distributed generation. Because the DG rider will govern all such customers formerly served under Residential RB rate, the Authority is proposing to eliminate the Residential RB rate to be replaced by the DG rider. Specifics of the DG rider, its development, and its pricing are discussed in greater detail below.

Elimination of the Residential Demand Service Rider (RD-13)

The RD rate rider was partially adapted to address concerns over customers utilizing tankless electric water heaters, which may cause a dramatic increase in customer demand and drive low customer load factors. In eliminating the RD rate rider, the Authority will amend the applicable language of the RT (Residential Time-Of-Use) rate to allow Santee Cooper to move low load factor customers to the RT rate.

Proposed Commercial Rate Designs

General

Unless otherwise noted below, the existing rate structures for the commercial rates are proposed to remain the same, including the use of a customer charge, seasonal energy charges, and demand charges where applicable. To better recover fixed costs from commercial customers not currently receiving service under a rate with a demand charge, the Authority has proposed an increase to the monthly customer charge. The Authority has also proposed an increase to the energy price differential between summer and non-summer months for the Commercial General Service (GA-13) rate. The change to the energy price differential is being proposed to better incentivize efficient use of the Authority's system. Adjustments to the Authority's Commercial rates also include proposed changes to the demand ratchet and to the on/off-peak timing of the GT-13 General Service Time-Of-Use Rate.

Commercial General Service Time-of-Use Rate (GT-16)

The Authority is proposing two changes to the GT rate: A modification of the demand ratchet and changes to the months defined as "Non-Summer" for the purposes of defining Non-Summer On-Peak hours.

The adjustment to the demand ratchet is being made to better align the GT rate with Santee Cooper's other commercial demand rates. The ratchet is being reduced to 30 percent of the customer's greatest on-peak demand for the preceding eleven months.

The Authority is also proposing to change the Non-Summer months to include March, April, May, October, and November. GT-13 is a rate that was developed to send pricing signals to customers that would encourage customers to shift usage to off-peak times. The proposed change to include such months as "Non-Summer" will reward customers that are able to shift load from on- to off-peak times, which leads to more efficient use of Santee Cooper's system and benefits all of the Authority's customers.

No change is currently being recommended to the times of day designated as "On-Peak."

Proposed Lighting Rates

General

The Authority has proposed the addition of LED options to its lighting service offerings on an experimental basis, and the lighting fixture exhibit has been modified to include energy charges in the Monthly Rental Charge. Otherwise, no structural changes to the Authority's rates are being proposed at this time.

Proposed Industrial Rates

Services provided under the Authority's industrial rate schedules are offered to customers with a potential demand for electric service of at least 1,000 kW. Service under the industrial rate schedules (Schedule L-12 and various rates, riders and successors thereto) are governed by General Terms and Conditions of Large Power Electric Service (see "General Terms and Conditions" attached to Schedule L-14). Electric power and energy delivered under industrial rates is characterized as unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, provided at one of the Authority's standard nominal voltages of 480 volts or higher.

There are several changes proposed to the industrial rate schedules. These include the following:

- Adjustment to the price for the first 300 kW of Firm Billed Demand and to the billing of off-peak additional demand under the Large Light and Power (L-14) rate.
- Elimination of the Large Light and Power Curtailable Supplemental Power Rider (L-13-SP).
- Adjustments to the Large Light and Power Interruptible Service Rider (L-13-I) including an update to the avoided CT cost calculation, creation of new longer-notification guidelines, and creation of protocol for scheduling charges to accompany all economic curtailments.
- Modifications to the pricing and scheduling charges of the Large Light and Power Economy Power Rider (L-13-EP).
- Creation of new Economy Power service offering: Large Light and Power Economy Power As-Used Rider (proposed L-16-EP-AU).

Firm Service

First 300kW of Firm Billed Demand

Santee Cooper proposes to increase the price of the first 300 kW of Firm Billed Demand and subsequently decrease the demand charge for additional billed demand after the first 300 kW. The existing L-14 rate includes a fixed charge for the first 300 kW of demand, and a $/kW rate for additional firm demand. The existing price per kW for the first 300 kW is equal to the price for additional kW of demand. The proposed change will increase the price for the first 300 kW and apply the increased revenue to reduce the demand charge ($/kW) for subsequent billed demand. The prices developed for this change are intended to yield a "revenue neutral" result across the Firm Industrial class as a whole.

This change is intended to reflect more appropriate fixed cost recovery from smaller Firm customers and reflects the economies of scale present in the Authority's service of larger Firm load. This change in pricing reflects the Authority's policy of encouraging the efficient use of Santee Cooper's system.

For the purposes of calculating the effective demand rate applicable to Interruptible customers, the updated value of the Interruptible credit (as further described below) will be applied to the non-adjusted firm demand rate (the rate determined prior to application of the premium or discount for the first 300 kW and subsequent kW, respectively).

Off-Peak Additional Demand Billed as Energy

The Authority has proposed an alteration to the L-14 rate, which would bill all off-peak additional demand as energy. This change would replace the former treatment of off-peak additional demand, which was billed at a demand charge with a provision to waive such charge at the Authority's discretion, and bill customers for off-peak demand as energy only.

Curtailable Supplemental Power Rider

Santee Cooper proposes to eliminate the Curtailable Supplemental rider (L-13-SP) effective December 31, 2015.

Interruptible Service

CT Pricing

As indicated previously, like other utilities, the Authority values the Interruptible Service based on the costs for an incremental CT generation unit in a simple cycle configuration.

The Authority hired the engineering, procurement, and construction services firm of WorleyParsons to conduct a construction cost estimate for various CT sizes located on either a brownfield or greenfield site. It was determined that a greenfield site represents the least cost resource that provides high reliability in a relative short-term planning horizon. This provides a reasonable and defensible basis for the cost of avoided generation. Leidos reviewed WorleyParsons' methodology for developing the CT cost estimate and determined it was consistent with industry standard practices.

To calculate the Interruptible Credit, Santee Cooper added to the WorleyParsons CT cost estimates additional costs for quick-start capability, owner's costs, and gas/transmission line upgrades to produce a value for total unit costs at each site for each technology. Santee Cooper also incorporated other indirect costs, as well as contributions to the Authority's CIF. The total summed costs were divided by the summer rated capacity (in kW) of the CT being evaluated, which serves as the Interruptible Credit as expressed in terms of dollars per kilowatt-month ($/kW-mo).

Longer-Notification Curtailments

Santee Cooper is proposing changes to its Interruptible service offering which include greater notice of potential economic curtailment and an increase in the possible duration of such curtailments. This proposed change is designed to avoid excessive fuel costs during periods of natural gas supply constraints.

The Authority requires a longer planning horizon and longer curtailment periods than are provided in the current Interruptible rate tariff. Increasing such curtailment guidelines will benefit all of Santee Cooper's customers by reducing fuel costs recovered through the Fuel Cost Adjustment. Santee Cooper's longer-notification curtailments will be limited to the months of January, February, and December.

Longer notification curtailments are envisioned to be economic curtailments, and as such, Interruptible customers may choose to "buy-through" such periods of longer-notification curtailment at the price communicated by Santee Cooper to such customers in advance of a need for such curtailment.

Proposed Scheduling Charges and Protocol

Along with changes proposed for Interruptible service detailed above, the Authority has also outlined new scheduling protocol. To receive Secondary Power during a period of Economic Curtailment, a customer must provide the requested 30-minute maximum integrated demand (kW) the customer is willing to receive during an interval determined by Santee Cooper ("Scheduled Secondary Demand"). Delivered Secondary Demand shall be defined as the maximum 30-minute demand (kW) metered as delivered to the customer in excess of that customer's Firm Contract Demand not to exceed the customer's Interruptible Service Contract Demand.

The Authority proposes to calculate charges for a customer's receipt of Secondary Power based on a markup over a quoted price for power, and the degree to which the customer over- or under-takes power based on Scheduled Secondary Demand. The quoted price for Secondary Power shall include the Authority's best estimate of incremental costs plus a margin of 15 percent. Charges for taking less than a customer's Scheduled Secondary Demand are assessed when Delivered Secondary Demand is less than 80 percent of Scheduled Secondary Demand for the interval. Charges are calculated as the amount by which Delivered Secondary Demand was less than 80 percent of Scheduled Secondary Demand times 15 percent of the quoted energy price times the number of hours in the interval. Such charges only apply when Delivered Secondary Demand is greater than 100 kW of Scheduled Secondary Demand for the interval. Charges when customer's Delivered Secondary Demand exceeds the Scheduled Secondary Demand are calculated as 150 percent of the quoted price for the interval times the number of clock hours in the interval. During a single curtailment period, divergence between Scheduled Secondary Demand and Delivered Secondary Demand may be levied on the basis of net difference over the interval of the curtailment, and charges may be calculated based on the average quoted price for energy during the curtailment period times the average number of interval clock hours. Such treatment of charges over the course of a single curtailment period is made available at the discretion of the Authority.

Economy Power Rider (L-13-EP)

The Authority is proposing changes to its existing Economy Power ("EP") rider to better align this service offering with its OATT.

The proposed changes to L-13-EP include explicit calculations for contributions to generation-related expenses as well as percentage-based contributions to CIF and charges associated with transmission losses. Additional changes include a reduction in the premium charged for power delivered in excess of a customer's scheduled energy for an hour to 150 percent of the hourly cost incurred. The Authority is also proposing to amend its charges for customers that utilize 90 percent (or less) of their scheduled power for any hour, which is a change from the current level of assessing charges for customers that utilize less than 100 percent of their scheduled power for any hour. This proposed change allows for greater latitude in customers not having to forecast demand with 100 percent accuracy.

Economy Power As Used (EP-AU)

Industrial Rate Rider L-16-EP-AU is being proposed as a new service offering to encourage use of incremental load when available. This rate is available to industrial customers who qualify under the specific terms and conditions identified in the L-16-EP-AU rate (see Appendix B for revised rate schedules).

EP-AU will be billed as an on-peak product, with timing defined by the L rate, but unlike EP and EP-O, will not be subject to a monthly reservation charge. EP-AU will be charged on the basis of energy, with the price consisting of the hourly quoted Economy Power price plus a premium per kWh charge to reflect a contribution to the Authority's fixed costs. EP-AU is designed to stimulate incremental on-peak energy usage, which will allow the customer the ability to increase load, when made available, by up to 10 percent of the customer's total contract demand. Thus, EP-AU will be available to a customer only after that customer has exceeded other contract demands.

Without EP-AU as a service offering, incremental load exceeding contract demand would be billed as excess, which is prohibitively costly to the Authority's Industrial customers and potentially serves as a deterrent to increasing load beyond contract demand. In accordance with Santee Cooper's objectives to stimulate the growth of load to benefit all the system's customers, EP-AU is specifically designed to be incremental in nature (10 percent of total contract demand) and does not include a reservation charge. As a result, it removes the potential disincentive that may discourage a customer to use incremental energy.

System Cost and Benefits of Demand Response Buy-Back (DRBB)

As part of the 2012 Electric Rate Study, the Authority proposed the development of Demand Response Buy-Back ("DRBB"), citing the value of interrupting/curtailing a single large "block" of load during short-notice events as being higher than the current value of the interruptible credit.

DRBB service provides a benefit to the firm customers of the system in the form of increased reliability for delivery of firm service, cost avoidance of maintaining or purchasing additional resources, and increased flexibility for the Authority to respond to system events. These benefits are valued at the cost incurred by the Authority for the DRBB Service purchases. The costs associated with this program are included in the Authority's overall revenue requirement for its system and are allocated to the Authority's customer classes similar to purchased power costs. The capacity portion of the DRBB Service costs (associated with the capacity credit) are allocated to the system customer classes utilizing a fixed cost (demand) allocator. The "per event" credit associated with the DRBB Service costs are allocated utilizing a variable cost (energy) allocator. This approach is consistent with cost causation and cost allocation principles utilized by the Authority in its rate making process.

At this time, the Authority is not proposing any changes to DRBB.

Municipal Rate (ML)

The ML rate serves as the basis for negotiated wholesale sales, the terms of which are designed to align with the ML rate offering over time. At this time, the Authority is not proposing to make any changes to its ML rate structure.

Proposed Fuel Adjustment

In response to feedback from the Authority's customers, Santee Cooper analyzed its fuel costs as a function of timing. Based on this analysis, the Authority did not determine that there was justifiable cause to differentiate pricing in the fuel adjustment based on timing. There are no changes proposed for the Fuel Adjustment Clause.

Demand Sales Adjustment Clause (DSC)

The Authority has proposed only one change to the Demand Sales Adjustment Clause ("DSC"), which is related to the manner by which revenues from the new EP-AU product will flow through the DSC. Revenues stemming from the portion of collected energy charges that correspond to the recovery of fixed costs under EP-AU will flow through the DSC. Otherwise, there are no changes proposed to the existing DSC methodology.

EDR Sales Adjustment Clause

The Economic Development Rider (L-13-ED-02) ("EDR") was approved by the Authority's Board of Directors on April 26, 2013. The EDR is available to customers who qualify that are directly served by the Authority, or directly served from power and energy requirements purchased by a wholesale customer from the Authority. The structure of the EDR provides for a sliding scale discount to the Schedule L Base Demand Charge. The Authority also offers service under the ED tiered service rider (L-14-ED-T), which offers a tiered discount to the L rate for larger load operating certain types of businesses as defined by a North American Industry Classification System ("NAICS") code.

For the term of this Study, the Authority has not forecasted directly serving any existing or new EDR customers, though Central serves several EDR customers (which is included in the LF1401). The current EDR tariff stipulates that service under the rider is available to new applicants through December 31, 2015 for ED-L13-02 and December 31, 2017 for L-14-ED-T. Revenues from Central's current EDR sales, and any future EDR sales pass through to firm requirements and interruptible service customers through the Economic Development Sales Adjustment Clause.

The purpose of the Economic Development Sales Adjustment Clause is to credit the Authority's firm requirements and interruptible service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority from the sales associated with the EDR, to the extent that such sales are not reflected in the effective rates for such customers. No changes are currently being proposed to the methodology for the Economic Development Sales Adjustment Clause.

Proposed Distributed Generation Rider (DG-16)

In accordance with South Carolina Act 236, the Authority has proposed the creation of a new rider that will govern service to all retail customers that opt to install distributed generation. As such, each retail rate is proposed to include a new line explicitly conveying the right of all customers to install self-generation, and refers such customers to the appropriate terms and conditions for the specifics of the rate.

The DG Rider applies to both residential and non-residential retail customers. Installed systems are capped in size at 20 kilowatts for residential, 1,000 kilowatts for commercial customers, or the estimated maximum monthly kilowatt demand of the customer.

Through the proposed DG Rider, customers will be billed monthly based on a combination of the following billing components:

- A metering charge: A monthly charge for metering and other customer-related costs, which is billed in addition to the monthly customer charge under the customer's applicable rate.
- A standby charge or demand charge (as applicable): Customers currently on a rate that includes a demand charge will not be subject to the DG Rider standby charge. The purpose of and methodology for developing the standby charge is described in greater detail below.
- Energy charges: Charges resulting from the energy the DG customer consumes from the Authority during hours in which customer load exceeds the customer's DG system production.
- Energy credits: Credits resulting from the energy the DG customer delivers back to the Authority during hours in which the customer's DG system production exceeds onsite load.

Regardless of available energy credits, a customer's minimum bill is equal to the customer charge effective under the customer's applicable rate, plus the monthly metering charge under the DG rider, plus any relevant standby charges or demand charges. If a customer's bill is reduced to the monthly minimum with additional energy credits remaining for the month, such credits will be carried forward to subsequent months (if credits are less than or equal $50), or will be reimbursed to the customer by the Authority (if credits exceed $50).

The standby charge of the DG Rider is indicative of the fixed costs the Authority incurs in being prepared to serve a DG customer's load in the event the production of the DG system is limited. The production of energy from photovoltaic ("PV") technologies varies with the availability of sunlight, and will likely fluctuate with the passing of clouds in daytime hours when the PV system would otherwise generate energy. During such times, Santee Cooper must maintain the infrastructure to be prepared to serve the DG customer's load, and Santee Cooper incurs costs associated with maintaining such preparedness.

The Authority's proposed standby charge was developed by multiplying demand-related costs per kW of serving Residential and Non-Residential customers by the expected capacity factor[5] of an average PV system located in South Carolina. Santee Cooper must provide standby service to a DG customer only during times in which the PV system is expected to produce power. During other times, the Authority will provide service to, and recover costs from, the DG customer under fully-embedded retail rates. Thus, the capacity factor for solar – or the average percentage of time a PV system is expected to produce power – functions as an appropriate proxy for estimating the percentage of demand-related costs the Authority would need to recover from the DG customer to provide standby service.

Because demand charges typically recover demand-related costs of service from DG customers adequately, a standby charge is not necessary for DG customers served under rates with effective demand rates. Thus, for such customers being served under rates with demand charges, the DG Rider standby charge will be waived.

With regard to Renewable Energy Credits produced by DG systems, Santee Cooper proposes to allow ownership of such produced credits to accrue to the customer. However, the Authority reserves the right under the proposed DG Rider to revisit such ownership of Renewable Energy Credits at its discretion.

[5] Capacity factor is the mathematical relationship (expressed as a percentage) between a generating system's rated capacity and the expected energy output of that system over a period of time. Thus, a system's capacity factor can also be described as the percentage of time that a system can reasonably be expected to produce power.

Section 6
PROPOSED RATES

The proposed rates were designed to meet the revenue requirements for the Test Years 2016, 2017 and 2018. To test the reasonableness of the proposed rates, an analysis using the projected billing units was prepared. Shown in Table No. 6-6 is the projected rate revenue by customer class using the proposed rates effective April 1 of 2016, 2017 and 2018.

Residential Service

The proposed residential rates have been designed to produce approximately $215,627,000 in 2016, $227,363,000 in 2017 and $235,363,000 in 2018.

The existing and proposed monthly rates for residential service are provided in Table 6-1 below:

Table 6-1
Existing and Proposed Residential Rates

	Description	Sch	Existing	Proposed – Effective April 1 2016	2017	2018
	Residential General Service	RG				
1	Customer Charge		$14.00	$17.00	$19.50	$21.00
	Energy Charge					
2	Summer		$0.1087	$0.1202	$0.1197	$0.1190
3	Non-Summer		$0.0987	$0.1002	$0.0997	$0.0990
	Good Cents	R1				
4	Customer Charge		$2.00	$9.00	$15.50	$21.00
	Energy Charge					
5	Summer		$0.1024	$0.1160	$0.1176	$0.1190
6	Non-Summer		$0.0924	$0.0960	$0.0976	$0.0990
	Good Cents	R2				
7	Customer Charge		$14.00	$17.00	$19.50	$21.00
	Energy Charge					
8	Summer		$0.1064	$0.1160	$0.1176	$0.1190
9	Non-Summer		$0.0964	$0.0960	$0.0976	$0.0990
	Good Cents	R3				
10	Customer Charge		$5.75	$11.50	$16.75	$21.00
	Energy Charge					
11	Summer		$0.1064	$0.1187	$0.1189	$0.1190
12	Non-Summer		$0.0964	$0.0987	$0.0989	$0.0990
	Good Cents	R4				
13	Customer Charge		$14.00	$17.00	$19.50	$21.00
	Energy Charge					
14	Summer		$0.1064	$0.1187	$0.1189	$0.1190
15	Non-Summer		$0.0964	$0.0987	$0.0989	$0.0990
	Residential Time-of-Use	RT				
16	Customer Charge		$24.00	$26.00	$28.00	$30.00
	Energy Charge					
17	Summer		$0.3179	$0.3277	$0.3499	$0.3520
18	Non-Summer		$0.2861	$0.2949	$0.3149	$0.3168
19	Non-Summer		$0.0699	$0.0609	$0.0625	$0.0633

Commercial Service

The proposed Commercial rates have been designed to produce approximately $191,612,000 in 2016, $202,004,000 in 2017, and $205,593,000 in 2018.

The existing and proposed monthly rates for Commercial Service are provided in Table 6-2 below:

Table 6-2
Existing and Proposed Commercial Rates

	Description	Sch	Existing	Proposed - Effective April 1 2016	2017	2018
	General Service	GA				
1	Customer Charge		$18.00	$21.00	$25.00	$27.50
	Energy Charge					
2	Summer		$0.0995	$0.1125	$0.1126	$0.1121
3	Non-Summer		$0.0895	$0.0925	$0.0926	$0.0921
	General Service Demand	GB				
4	Customer Charge		$22.00	$25.00	$26.00	$26.00
5	Demand Charge		$19.88	$22.94	$23.42	$23.60
	Energy Charge					
6	Summer		$0.0475	$0.0475	$0.0475	$0.0475
7	Non-Summer		$0.0375	$0.0375	$0.0375	$0.0375
	Seasonal General	GV				
8	Customer Charge		$22.00	$25.00	$26.00	$26.00
9	Demand Charge		$21.60	$24.60	$25.04	$25.74
	Energy Charge					
10	Summer		$0.0475	$0.0475	$0.0475	$0.0475
11	Non-Summer		$0.0375	$0.0375	$0.0375	$0.0375
	Gen. Service Time-of-Use	GT				
12	Customer Charge		$30.00	$30.00	$31.00	$31.00
13	On-Peak Dem Chg		$21.95	$25.23	$25.76	$25.96
14	Off-Peak Dem Chg		$13.60	$13.28	$13.94	$14.58
	Energy Charge					
15	Summer		$0.0475	$0.0475	$0.0475	$0.0475
16	Non-Summer		$0.0475	$0.0475	$0.0475	$0.0475
17	Off-Peak Hours		$0.0375	$0.0375	$0.0375	$0.0375
	Large General Serv	GL				
18	Customer Charge		$25.00	$25.00	$26.00	$26.00
19	Demand Charge		$20.33	$23.29	$23.60	$23.83
	Energy Charge					
20	Summer		$0.0462	$0.0465	$0.0465	$0.0465
21	Non-Summer		$0.0362	$0.0365	$0.0365	$0.0365

	Description	Sch	Existing	Proposed - Effective April 1 2016	2017	2018
	Temporary Service	TP				
22	Customer Charge		$18.00	$21.00	$22.00	$23.00
	Energy Charge					
23	Summer		$0.1254	$0.1406	$0.1412	$0.1468
24	Non-Summer		$0.1154	$0.1206	$0.1212	$0.1268
	Transition Adjustment	TA				
25	Customer Charge		$22.00	$25.00	$26.00	$26.00
26	Demand Charge		$6.16	$9.75	$12.65	$15.46
	Energy Charge					
27	Summer		$0.0813	$0.0756	$0.0700	$0.0644
28	Non-Summer		$0.0713	$0.0656	$0.0600	$0.0544

Lighting Service

The proposed Lighting rates have been designed to produce approximately $11,714,000 in 2016, $12,216,000 in 2017 and $12,345,000 in 2018.

The existing and proposed monthly rates for Lighting Service are provided in Table 6-3 below:

Table 6-3
Existing and Proposed Lighting Rates

	Description	Sch	Existing	Proposed - Effective April 1 2016	2017	2018
	Traffic Signal Service	TL				
1	Customer Charge		$18.00	$21.00	$25.00	$27.50
2	Base Energy Charge		$0.0974	$0.1000	$0.1010	$0.1018
	Energy Charge					
3	Per Lamp 25 W or less		$1.51	$1.53	$1.60	$1.66
4	Per Lamp 26 to 70 W		$2.03	$2.17	$2.21	$2.25
5	Per Lamp > 70 W		$2.71	$2.99	$3.00	$3.02
	Municipal Street Lighting	MS				
6	Energy Charge		$0.0591	$0.0639	$0.0661	$0.0662
	Private Outdoor Lighting	OL				
7	Energy Charge		$0.0591	$0.0639	$0.0661	$0.0662
	Pole Attachment	PA				
8	Monthly Charge		$13.60	$14.60	$14.60	$14.60
9	Annual Charge		$0.0974	$0.1000	$0.1010	$0.1018

Industrial Service

The proposed Industrial rates for Firm service have been designed to produce approximately $82,815,000 in 2016, $86,370,000 in 2017 and $87,528,000 in 2018.

The existing and proposed monthly rates for Industrial Service are provided in Table 6-4 below:

Table 6-4
Existing and Proposed Industrial Rates

				Proposed - Effective April 1		
	Description	Sch	Existing	2016	2017	2018
	Large Light & Power	L				
1	Customer Charge		$3,000.00	$3,400.00	$3,400.00	$3,400.00
2	Base Dem First 300 kW		$4,989.00	$7,332.00	$7,511.40	$7,663.50
3	Additional kW Demand		$16.62	$18.80	$19.26	$19.65
4	Transformation Discount		$0.60	$0.60	$0.60	$0.60
5	Excess Demand Charge		$10.00	$11.00	$12.00	$12.00
6	Excess Reactive Demand		$0.82	$0.82	$0.82	$0.82
7	On-Peak Energy Charge		$0.0575	$0.0575	$0.0575	$0.0575
8	Off-Peak Energy Charge		$0.0375	$0.0375	$0.0375	$0.0375
	Interruptible Service	L-I				
9	Demand Charge		$8.91	$10.18	$10.31	$10.31
10	On-Peak Energy Charge		$0.0575	$0.0575	$0.0575	$0.0575
11	Off-Peak Energy Charge		$0.0375	$0.0375	$0.0375	$0.0375
	Economy Power Service	L-EP				
12	Customer Charge		$800.00	$1,000.00	$1,000.00	$1,000.00
13	Reservation Charge		$1.64	$1.77	$1.81	$1.87
	EP Optional Energy Chg	L-EP-O				
14	Reservation Charge		$3.20	$3.53	$3.66	$3.75
15	Off-Peak Energy Charge		$0.0375	$0.0375	$0.0375	$0.0375
	EP As Used	AU				
16	Hourly Energy Charge		--	$0.0199	$0.0210	$0.0218
	Standby Service	L-SB				
17	Reservation Charge		$3.20	$3.53	$3.66	$3.75
18	Standby Demand Charge		$12.70	$13.77	$14.34	$14.69
	Demand Resp Buy Back	DRB				
19	Monthly Credit		$563.00	$586.00	$614.00	$665.00
20	Annual Charge		$338.00	$293.00	$307.00	$333.00
	Distributed Gen. Rider	DG				
21	Metering Charge		--	$9.00	$9.00	$9.00
22	Standby Fee - Residential		--	$4.70	$4.70	$4.70
23	Standby Fee – Comm.		--	$5.00	$5.00	$5.00
24	Summer Credit		--	$0.0389	$0.0416	$0.0419
25	Non-Summer Credit		--	$0.0381	$0.0384	$0.0408

Summary

Table 6-5 below provides a comparison, as summarized from Tables 6.1 - 6.4, of the projected revenues of the Test Years produced by applying the projected billing determinants to the existing rates and the proposed rates for each classification:

Table 6-5
Summary of Proposed Revenues

		Rate	Proposed Revenues ($000)		
	Type of Service	Code	2016	2017	2018
	Residential:				
1	Residential General Service	RG	$198,455	$210,066	$218,275
2	Residential Good Cents (New) Standard Plus	R1	7,847	7,830	7,657
3	Residential Good Cents (New) Standard	R2	2,558	2,498	2,387
4	Res. Good Cents (Improved Home) Standard Plus	R3	5,657	5,877	5,986
5	Res. Good Cents (Improved Home) Standard	R4	1,110	1,092	1,057
6	Total Residential Revenues		215,627	227,363	235,363
	Commercial:				
7	General Service	GA	45,579	47,572	48,283
8	General Service Demand	GB	120,411	127,355	129,437
9	Seasonal General Service	GV	2,376	2,491	2,549
10	Large General Service	GL	16,359	17,194	17,458
11	General Service Time of Use	GT	415	433	443
12	Transition Adjustment	TA	2,206	2,525	2,788
13	Temporary Service	TP	4,215	4,381	4,582
14	Traffic Signal Service	TL	51	53	53
15	Total Commercial Revenues		191,612	202,004	205,593
	Lighting:				
16	Municipal Street Lighting	MS	3,283	3,425	3,460
17	Private Outdoor Lighting	OL	8,431	8,791	8,885
18	Total Lighting Revenues		11,714	12,216	12,345
	Industrial:				
19	Large Light and Power	L	82,815	86,370	87,528
20	Total Large Light and Power		82,815	86,370	87,528
21	Total Proposed Revenues		$501,768	$527,934	$540,952

Percent Increase in Revenue Recovery

Table 6-6 below provides a summary of the percent increase in firm revenue recovery for major rate classifications. Appendix A shows the calculations of the monthly bills assuming the existing and proposed rates at a variety of energy/demand usage.

Table 6-6
Proposed Firm Revenue Adjustments
Percent Increase in Revenue Recovery Under Existing Rates

		Year to Year Percent Increases		
	Service	2016	2017	2018
1	Residential	6.7%	2.2%	1.3%
2	Commercial	6.6%	2.7%	0.8%
3	Lighting	7.0%	2.6%	0.4%
4	Industrial (Firm)	3.8%	2.2%	0.9%
5	Total	6.2%	2.4%	1.0%

Appendix A
BILL COMPARISONS

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Residential Service Rates

		Rate Code RG	
		Existing	Proposed 2016
Customer Charge	($)	$14.00	$17.00
Energy Charge - Summer	($/kWh)	$0.10870	$0.12020
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	45.47	15.157	51.92	17.307	6.45	2.150	14.19%
400	55.96	13.990	63.56	15.890	7.60	1.900	13.58%
500	66.45	13.290	75.20	15.040	8.75	1.750	13.17%
600	76.94	12.823	86.84	14.473	9.90	1.650	12.87%
700	87.43	12.490	98.48	14.069	11.05	1.579	12.64%
800	97.92	12.240	110.12	13.765	12.20	1.525	12.46%
900	108.41	12.046	121.76	13.529	13.35	1.483	12.31%
1,000	118.90	11.890	133.40	13.340	14.50	1.450	12.20%
1,100	129.39	11.763	145.04	13.185	15.65	1.423	12.10%
1,200	139.88	11.657	156.68	13.057	16.80	1.400	12.01%
1,300	150.37	11.567	168.32	12.948	17.95	1.381	11.94%
1,400	160.86	11.490	179.96	12.854	19.10	1.364	11.87%
1,500	171.35	11.423	191.60	12.773	20.25	1.350	11.82%
2,000	223.80	11.190	249.80	12.490	26.00	1.300	11.62%
2,500	276.25	11.050	308.00	12.320	31.75	1.270	11.49%
3,000	328.70	10.957	366.20	12.207	37.50	1.250	11.41%
4,000	433.60	10.840	482.60	12.065	49.00	1.225	11.30%
5,000	538.50	10.770	599.00	11.980	60.50	1.210	11.23%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Residential Service Rates

		Rate Code RG	
		Existing	Proposed 2016
Customer Charge	($)	$14.00	$17.00
Energy Charge - Non Summer	($/kWh)	$0.09870	$0.10020
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	42.21	14.069	45.66	15.219	3.45	1.150	8.17%
400	51.61	12.902	55.21	13.802	3.60	0.900	6.98%
500	61.01	12.202	64.76	12.952	3.75	0.750	6.15%
600	70.41	11.735	74.31	12.385	3.90	0.650	5.54%
700	79.81	11.402	83.86	11.981	4.05	0.579	5.07%
800	89.22	11.152	93.42	11.677	4.20	0.525	4.71%
900	98.62	10.958	102.97	11.441	4.35	0.483	4.41%
1,000	108.02	10.802	112.52	11.252	4.50	0.450	4.17%
1,100	117.42	10.675	122.07	11.097	4.65	0.423	3.96%
1,200	126.82	10.569	131.62	10.969	4.80	0.400	3.78%
1,300	136.23	10.479	141.18	10.860	4.95	0.381	3.63%
1,400	145.63	10.402	150.73	10.766	5.10	0.364	3.50%
1,500	155.03	10.335	160.28	10.685	5.25	0.350	3.39%
2,000	202.04	10.102	208.04	10.402	6.00	0.300	2.97%
2,500	249.05	9.962	255.80	10.232	6.75	0.270	2.71%
3,000	296.06	9.869	303.56	10.119	7.50	0.250	2.53%
4,000	390.08	9.752	399.08	9.977	9.00	0.225	2.31%
5,000	484.10	9.682	494.60	9.892	10.50	0.210	2.17%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Residential Service Rates

		Rate Code R2	
		Existing	Proposed 2016
Customer Charge	($)	$14.00	$17.00
Energy Charge - Summer	($/kWh)	$0.10240	$0.11600
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	43.58	14.527	50.66	16.887	7.08	2.360	16.25%
400	53.44	13.360	61.88	15.470	8.44	2.110	15.79%
500	63.30	12.660	73.10	14.620	9.80	1.960	15.48%
600	73.16	12.193	84.32	14.053	11.16	1.860	15.25%
700	83.02	11.860	95.54	13.649	12.52	1.789	15.08%
800	92.88	11.610	106.76	13.345	13.88	1.735	14.94%
900	102.74	11.416	117.98	13.109	15.24	1.693	14.83%
1,000	112.60	11.260	129.20	12.920	16.60	1.660	14.74%
1,100	122.46	11.133	140.42	12.765	17.96	1.633	14.67%
1,200	132.32	11.027	151.64	12.637	19.32	1.610	14.60%
1,300	142.18	10.937	162.86	12.528	20.68	1.591	14.54%
1,400	152.04	10.860	174.08	12.434	22.04	1.574	14.50%
1,500	161.90	10.793	185.30	12.353	23.40	1.560	14.45%
2,000	211.20	10.560	241.40	12.070	30.20	1.510	14.30%
2,500	260.50	10.420	297.50	11.900	37.00	1.480	14.20%
3,000	309.80	10.327	353.60	11.787	43.80	1.460	14.14%
4,000	408.40	10.210	465.80	11.645	57.40	1.435	14.05%
5,000	507.00	10.140	578.00	11.560	71.00	1.420	14.00%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Residential Service Rates

		Rate Code R2 Existing	Rate Code R2 Proposed 2016
Customer Charge	($)	$14.00	$17.00
Energy Charge - Non-Summer	($/kWh)	$0.09240	$0.09600
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	40.32	13.439	44.40	14.799	4.08	1.360	10.12%
400	49.09	12.272	53.53	13.382	4.44	1.110	9.04%
500	57.86	11.572	62.66	12.532	4.80	0.960	8.30%
600	66.63	11.105	71.79	11.965	5.16	0.860	7.74%
700	75.40	10.772	80.92	11.561	5.52	0.789	7.32%
800	84.18	10.522	90.06	11.257	5.88	0.735	6.99%
900	92.95	10.328	99.19	11.021	6.24	0.693	6.71%
1,000	101.72	10.172	108.32	10.832	6.60	0.660	6.49%
1,100	110.49	10.045	117.45	10.677	6.96	0.633	6.30%
1,200	119.26	9.939	126.58	10.549	7.32	0.610	6.14%
1,300	128.04	9.849	135.72	10.440	7.68	0.591	6.00%
1,400	136.81	9.772	144.85	10.346	8.04	0.574	5.88%
1,500	145.58	9.705	153.98	10.265	8.40	0.560	5.77%
2,000	189.44	9.472	199.64	9.982	10.20	0.510	5.38%
2,500	233.30	9.332	245.30	9.812	12.00	0.480	5.14%
3,000	277.16	9.239	290.96	9.699	13.80	0.460	4.98%
4,000	364.88	9.122	382.28	9.557	17.40	0.435	4.77%
5,000	452.60	9.052	473.60	9.472	21.00	0.420	4.64%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Residential Service Rates

		Rate Code R4	
		Existing	Proposed 2016
Customer Charge	($)	$14.00	$17.00
Energy Charge - Summer	($/kWh)	$0.10640	$0.11870
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	44.78	14.927	51.47	17.157	6.69	2.230	14.94%
400	55.04	13.760	62.96	15.740	7.92	1.980	14.39%
500	65.30	13.060	74.45	14.890	9.15	1.830	14.01%
600	75.56	12.593	85.94	14.323	10.38	1.730	13.74%
700	85.82	12.260	97.43	13.919	11.61	1.659	13.53%
800	96.08	12.010	108.92	13.615	12.84	1.605	13.36%
900	106.34	11.816	120.41	13.379	14.07	1.563	13.23%
1,000	116.60	11.660	131.90	13.190	15.30	1.530	13.12%
1,100	126.86	11.533	143.39	13.035	16.53	1.503	13.03%
1,200	137.12	11.427	154.88	12.907	17.76	1.480	12.95%
1,300	147.38	11.337	166.37	12.798	18.99	1.461	12.89%
1,400	157.64	11.260	177.86	12.704	20.22	1.444	12.83%
1,500	167.90	11.193	189.35	12.623	21.45	1.430	12.78%
2,000	219.20	10.960	246.80	12.340	27.60	1.380	12.59%
2,500	270.50	10.820	304.25	12.170	33.75	1.350	12.48%
3,000	321.80	10.727	361.70	12.057	39.90	1.330	12.40%
4,000	424.40	10.610	476.60	11.915	52.20	1.305	12.30%
5,000	527.00	10.540	591.50	11.830	64.50	1.290	12.24%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Residential Service Rates

		Rate Code R4	
		Existing	Proposed 2016
Customer Charge	($)	$14.00	$17.00
Energy Charge - Non Summer	($/kWh)	$0.09640	$0.09870
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	41.52	13.839	45.21	15.069	3.69	1.230	8.89%
400	50.69	12.672	54.61	13.652	3.92	0.980	7.73%
500	59.86	11.972	64.01	12.802	4.15	0.830	6.93%
600	69.03	11.505	73.41	12.235	4.38	0.730	6.34%
700	78.20	11.172	82.81	11.831	4.61	0.659	5.89%
800	87.38	10.922	92.22	11.527	4.84	0.605	5.54%
900	96.55	10.728	101.62	11.291	5.07	0.563	5.25%
1,000	105.72	10.572	111.02	11.102	5.30	0.530	5.01%
1,100	114.89	10.445	120.42	10.947	5.53	0.503	4.81%
1,200	124.06	10.339	129.82	10.819	5.76	0.480	4.64%
1,300	133.24	10.249	139.23	10.710	5.99	0.461	4.50%
1,400	142.41	10.172	148.63	10.616	6.22	0.444	4.37%
1,500	151.58	10.105	158.03	10.535	6.45	0.430	4.26%
2,000	197.44	9.872	205.04	10.252	7.60	0.380	3.85%
2,500	243.30	9.732	252.05	10.082	8.75	0.350	3.60%
3,000	289.16	9.639	299.06	9.969	9.90	0.330	3.42%
4,000	380.88	9.522	393.08	9.827	12.20	0.305	3.20%
5,000	472.60	9.452	487.10	9.742	14.50	0.290	3.07%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GA Existing	Rate Code GA Proposed 2016
Customer Charge	($)	$18.00	$21.00
Energy Charge - Summer	($/kWh)	$0.09950	$0.11250
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	46.71	15.570	53.61	17.870	6.90	2.300	14.77%
400	56.28	14.070	64.48	16.120	8.20	2.050	14.57%
500	65.85	13.170	75.35	15.070	9.50	1.900	14.43%
750	89.78	11.970	102.53	13.670	12.75	1.700	14.20%
1,000	113.70	11.370	129.70	12.970	16.00	1.600	14.07%
2,000	209.40	10.470	238.40	11.920	29.00	1.450	13.85%
3,000	305.10	10.170	347.10	11.570	42.00	1.400	13.77%
4,000	400.80	10.020	455.80	11.395	55.00	1.375	13.72%
5,000	496.50	9.930	564.50	11.290	68.00	1.360	13.70%
6,000	592.20	9.870	673.20	11.220	81.00	1.350	13.68%
7,000	687.90	9.827	781.90	11.170	94.00	1.343	13.66%
8,000	783.60	9.795	890.60	11.133	107.00	1.338	13.65%
9,000	879.30	9.770	999.30	11.103	120.00	1.333	13.65%
10,000	975.00	9.750	1,108.00	11.080	133.00	1.330	13.64%
11,000	1,070.70	9.734	1,216.70	11.061	146.00	1.327	13.64%
12,000	1,166.40	9.720	1,325.40	11.045	159.00	1.325	13.63%
13,000	1,262.10	9.708	1,434.10	11.032	172.00	1.323	13.63%
14,000	1,357.80	9.699	1,542.80	11.020	185.00	1.321	13.62%
15,000	1,453.50	9.690	1,651.50	11.010	198.00	1.320	13.62%
20,000	1,932.00	9.660	2,195.00	10.975	263.00	1.315	13.61%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GA	
		Existing	Proposed 2016
Customer Charge	($)	$18.00	$21.00
Energy Charge - Non Summer	($/kWh)	$0.08950	$0.09250
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	43.45	14.482	47.35	15.782	3.90	1.300	8.98%
400	51.93	12.982	56.13	14.032	4.20	1.050	8.09%
500	60.41	12.082	64.91	12.982	4.50	0.900	7.45%
750	81.62	10.882	86.87	11.582	5.25	0.700	6.43%
1,000	102.82	10.282	108.82	10.882	6.00	0.600	5.84%
2,000	187.64	9.382	196.64	9.832	9.00	0.450	4.80%
3,000	272.46	9.082	284.46	9.482	12.00	0.400	4.40%
4,000	357.28	8.932	372.28	9.307	15.00	0.375	4.20%
5,000	442.10	8.842	460.10	9.202	18.00	0.360	4.07%
6,000	526.92	8.782	547.92	9.132	21.00	0.350	3.99%
7,000	611.74	8.739	635.74	9.082	24.00	0.343	3.92%
8,000	696.56	8.707	723.56	9.045	27.00	0.337	3.88%
9,000	781.38	8.682	811.38	9.015	30.00	0.333	3.84%
10,000	866.20	8.662	899.20	8.992	33.00	0.330	3.81%
11,000	951.02	8.646	987.02	8.973	36.00	0.327	3.79%
12,000	1,035.84	8.632	1,074.84	8.957	39.00	0.325	3.77%
13,000	1,120.66	8.620	1,162.66	8.944	42.00	0.323	3.75%
14,000	1,205.48	8.611	1,250.48	8.932	45.00	0.321	3.73%
15,000	1,290.30	8.602	1,338.30	8.922	48.00	0.320	3.72%
20,000	1,714.40	8.572	1,777.40	8.887	63.00	0.315	3.67%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GB	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$19.88	$22.94
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	1,335.01	18.288	1,491.01	20.425	156.00	2.137	11.69%
	30%	10,950	1,494.52	13.649	1,650.52	15.073	156.00	1.425	10.44%
	40%	14,600	1,654.02	11.329	1,810.02	12.397	156.00	1.068	9.43%
	50%	18,250	1,813.53	9.937	1,969.53	10.792	156.00	0.855	8.60%
	60%	21,900	1,973.03	9.009	2,129.03	9.722	156.00	0.712	7.91%
	70%	25,550	2,132.54	8.347	2,288.54	8.957	156.00	0.611	7.32%
	80%	29,200	2,292.04	7.849	2,448.04	8.384	156.00	0.534	6.81%
100	20%	14,600	2,648.02	18.137	2,957.02	20.254	309.00	2.116	11.67%
	30%	21,900	2,967.03	13.548	3,276.03	14.959	309.00	1.411	10.41%
	40%	29,200	3,286.04	11.254	3,595.04	12.312	309.00	1.058	9.40%
	50%	36,500	3,605.05	9.877	3,914.05	10.723	309.00	0.847	8.57%
	60%	43,800	3,924.06	8.959	4,233.06	9.665	309.00	0.705	7.87%
	70%	51,100	4,243.07	8.303	4,552.07	8.908	309.00	0.605	7.28%
	80%	58,400	4,562.08	7.812	4,871.08	8.341	309.00	0.529	6.77%
200	20%	29,200	5,274.04	18.062	5,889.04	20.168	615.00	2.106	11.66%
	30%	43,800	5,912.06	13.498	6,527.06	14.902	615.00	1.404	10.40%
	40%	58,400	6,550.08	11.216	7,165.08	12.269	615.00	1.053	9.39%
	50%	73,000	7,188.10	9.847	7,803.10	10.689	615.00	0.842	8.56%
	60%	87,600	7,826.12	8.934	8,441.12	9.636	615.00	0.702	7.86%
	70%	102,200	8,464.14	8.282	9,079.14	8.884	615.00	0.602	7.27%
	80%	116,800	9,102.16	7.793	9,717.16	8.319	615.00	0.527	6.76%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GB	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$19.88	$22.94
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	**20%**	**43,800**	7,900.06	18.037	8,821.06	20.139	921.00	2.103	11.66%
	30%	**65,700**	8,857.09	13.481	9,778.09	14.883	921.00	1.402	10.40%
	40%	**87,600**	9,814.12	11.203	10,735.12	12.255	921.00	1.051	9.38%
	50%	**109,500**	10,771.15	9.837	11,692.15	10.678	921.00	0.841	8.55%
	60%	**131,400**	11,728.18	8.926	12,649.18	9.626	921.00	0.701	7.85%
	70%	**153,300**	12,685.21	8.275	13,606.21	8.876	921.00	0.601	7.26%
	80%	**175,200**	13,642.24	7.787	14,563.24	8.312	921.00	0.526	6.75%
400	**20%**	**58,400**	10,526.08	18.024	11,753.08	20.125	1,227.00	2.101	11.66%
	30%	**87,600**	11,802.12	13.473	13,029.12	14.873	1,227.00	1.401	10.40%
	40%	**116,800**	13,078.16	11.197	14,305.16	12.248	1,227.00	1.051	9.38%
	50%	**146,000**	14,354.20	9.832	15,581.20	10.672	1,227.00	0.840	8.55%
	60%	**175,200**	15,630.24	8.921	16,857.24	9.622	1,227.00	0.700	7.85%
	70%	**204,400**	16,906.28	8.271	18,133.28	8.871	1,227.00	0.600	7.26%
	80%	**233,600**	18,182.32	7.784	19,409.32	8.309	1,227.00	0.525	6.75%
500	**20%**	**73,000**	13,152.10	18.017	14,685.10	20.117	1,533.00	2.100	11.66%
	30%	**109,500**	14,747.15	13.468	16,280.15	14.868	1,533.00	1.400	10.40%
	40%	**146,000**	16,342.20	11.193	17,875.20	12.243	1,533.00	1.050	9.38%
	50%	**182,500**	17,937.25	9.829	19,470.25	10.669	1,533.00	0.840	8.55%
	60%	**219,000**	19,532.30	8.919	21,065.30	9.619	1,533.00	0.700	7.85%
	70%	**255,500**	21,127.35	8.269	22,660.35	8.869	1,533.00	0.600	7.26%
	80%	**292,000**	22,722.40	7.782	24,255.40	8.307	1,533.00	0.525	6.75%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GB	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$19.88	$22.94
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Load		Existing		Proposed 2016		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,300	1,255.59	17.200	1,411.59	19.337	156.00	2.137	12.42%
	30%	10,950	1,375.38	12.561	1,531.38	13.985	156.00	1.425	11.34%
	40%	14,600	1,495.17	10.241	1,651.17	11.309	156.00	1.068	10.43%
	50%	18,250	1,614.97	8.849	1,770.97	9.704	156.00	0.855	9.66%
	60%	21,900	1,734.76	7.921	1,890.76	8.634	156.00	0.712	8.99%
	70%	25,550	1,854.55	7.259	2,010.55	7.869	156.00	0.611	8.41%
	80%	29,200	1,974.34	6.761	2,130.34	7.296	156.00	0.534	7.90%
100	20%	14,600	2,489.17	17.049	2,798.17	19.166	309.00	2.116	12.41%
	30%	21,900	2,728.76	12.460	3,037.76	13.871	309.00	1.411	11.32%
	40%	29,200	2,968.34	10.166	3,277.34	11.224	309.00	1.058	10.41%
	50%	36,500	3,207.93	8.789	3,516.93	9.635	309.00	0.847	9.63%
	60%	43,800	3,447.52	7.871	3,756.52	8.577	309.00	0.705	8.96%
	70%	51,100	3,687.10	7.215	3,996.10	7.820	309.00	0.605	8.38%
	80%	58,400	3,926.69	6.724	4,235.69	7.253	309.00	0.529	7.87%
200	20%	29,200	4,956.34	16.974	5,571.34	19.080	615.00	2.106	12.41%
	30%	43,800	5,435.52	12.410	6,050.52	13.814	615.00	1.404	11.31%
	40%	58,400	5,914.69	10.128	6,529.69	11.181	615.00	1.053	10.40%
	50%	73,000	6,393.86	8.759	7,008.86	9.601	615.00	0.842	9.62%
	60%	87,600	6,873.03	7.846	7,488.03	8.548	615.00	0.702	8.95%
	70%	102,200	7,352.20	7.194	7,967.20	7.796	615.00	0.602	8.36%
	80%	116,800	7,831.38	6.705	8,446.38	7.231	615.00	0.527	7.85%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GB	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$19.88	$22.94
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

Demand (kW)	Load Factor	Usage (kWh)	Existing Amount ($)	Existing Unit Cost (Cents/kWh)	Proposed 2016 Amount ($)	Proposed 2016 Unit Cost (Cents/kWh)	Difference Amount ($)	Difference Unit Cost (Cents/kWh)	Difference Percent (%)
300	**20%**	**43,800**	7,423.52	16.949	8,344.52	19.051	921.00	2.103	12.41%
	30%	**65,700**	8,142.27	12.393	9,063.27	13.795	921.00	1.402	11.31%
	40%	**87,600**	8,861.03	10.115	9,782.03	11.167	921.00	1.051	10.39%
	50%	**109,500**	9,579.79	8.749	10,500.79	9.590	921.00	0.841	9.61%
	60%	**131,400**	10,298.55	7.838	11,219.55	8.538	921.00	0.701	8.94%
	70%	**153,300**	11,017.31	7.187	11,938.31	7.788	921.00	0.601	8.36%
	80%	**175,200**	11,736.06	6.699	12,657.06	7.224	921.00	0.526	7.85%
400	**20%**	**58,400**	9,890.69	16.936	11,117.69	19.037	1,227.00	2.101	12.41%
	30%	**87,600**	10,849.03	12.385	12,076.03	13.785	1,227.00	1.401	11.31%
	40%	**116,800**	11,807.38	10.109	13,034.38	11.160	1,227.00	1.051	10.39%
	50%	**146,000**	12,765.72	8.744	13,992.72	9.584	1,227.00	0.840	9.61%
	60%	**175,200**	13,724.06	7.833	14,951.06	8.534	1,227.00	0.700	8.94%
	70%	**204,400**	14,682.41	7.183	15,909.41	7.783	1,227.00	0.600	8.36%
	80%	**233,600**	15,640.75	6.696	16,867.75	7.221	1,227.00	0.525	7.84%
500	**20%**	**73,000**	12,357.86	16.929	13,890.86	19.029	1,533.00	2.100	12.41%
	30%	**109,500**	13,555.79	12.380	15,088.79	13.780	1,533.00	1.400	11.31%
	40%	**146,000**	14,753.72	10.105	16,286.72	11.155	1,533.00	1.050	10.39%
	50%	**182,500**	15,951.65	8.741	17,484.65	9.581	1,533.00	0.840	9.61%
	60%	**219,000**	17,149.58	7.831	18,682.58	8.531	1,533.00	0.700	8.94%
	70%	**255,500**	18,347.51	7.181	19,880.51	7.781	1,533.00	0.600	8.36%
	80%	**292,000**	19,545.44	6.694	21,078.44	7.219	1,533.00	0.525	7.84%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GL	
		Existing	Proposed 2016
Customer Charge	($)	$25.00	$25.00
Demand Charge	($/kW)	$20.33	$23.29
Energy Charge - Summer	($/kWh)	$0.04620	$0.04650
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	**70%**	**153,300**	12,623.92	8.235	13,557.91	8.844	933.99	0.609	7.40%
	80%	**175,200**	13,552.48	7.735	14,493.04	8.272	940.56	0.537	6.94%
	90%	**197,100**	14,481.04	7.347	15,428.17	7.828	947.13	0.481	6.54%
400	**70%**	**204,400**	16,823.56	8.231	18,068.88	8.840	1,245.32	0.609	7.40%
	80%	**233,600**	18,061.64	7.732	19,315.72	8.269	1,254.08	0.537	6.94%
	90%	**262,800**	19,299.72	7.344	20,562.56	7.824	1,262.84	0.481	6.54%
500	**70%**	**255,500**	21,023.20	8.228	22,579.85	8.838	1,556.65	0.609	7.40%
	80%	**292,000**	22,570.80	7.730	24,138.40	8.267	1,567.60	0.537	6.95%
	90%	**328,500**	24,118.40	7.342	25,696.95	7.823	1,578.55	0.481	6.55%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GL	
		Existing	Proposed 2016
Customer Charge	($)	$25.00	$25.00
Demand Charge	($/kW)	$20.33	$23.29
Energy Charge - Summer	($/kWh)	$0.04620	$0.04650
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
600	**70%**	**306,600**	25,222.84	8.227	27,090.82	8.836	1,867.98	0.609	7.41%
	80%	**350,400**	27,079.96	7.728	28,961.08	8.265	1,881.12	0.537	6.95%
	90%	**394,200**	28,937.08	7.341	30,831.34	7.821	1,894.26	0.481	6.55%
800	**70%**	**408,800**	33,622.12	8.225	36,112.76	8.834	2,490.64	0.609	7.41%
	80%	**467,200**	36,098.28	7.727	38,606.44	8.263	2,508.16	0.537	6.95%
	90%	**525,600**	38,574.44	7.339	41,100.12	7.820	2,525.68	0.481	6.55%
1000	**70%**	**511,000**	42,021.40	8.223	45,134.70	8.833	3,113.30	0.609	7.41%
	80%	**584,000**	45,116.60	7.725	48,251.80	8.262	3,135.20	0.537	6.95%
	90%	**657,000**	48,211.80	7.338	51,368.90	7.819	3,157.10	0.481	6.55%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GL	
		Existing	Proposed 2016
Customer Charge	($)	$25.00	$25.00
Demand Charge	($/kW)	$20.33	$23.29
Energy Charge - Non Summer	($/kWh)	$0.03620	$0.03650
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	**70%**	**153,300**	10,956.02	7.147	11,890.01	7.756	933.99	0.609	8.52%
	80%	**175,200**	11,646.30	6.647	12,586.86	7.184	940.56	0.537	8.08%
	90%	**197,100**	12,336.59	6.259	13,283.72	6.740	947.13	0.481	7.68%
400	**70%**	**204,400**	14,599.69	7.143	15,845.01	7.752	1,245.32	0.609	8.53%
	80%	**233,600**	15,520.07	6.644	16,774.15	7.181	1,254.08	0.537	8.08%
	90%	**262,800**	16,440.46	6.256	17,703.30	6.736	1,262.84	0.481	7.68%
500	**70%**	**255,500**	18,243.36	7.140	19,800.01	7.750	1,556.65	0.609	8.53%
	80%	**292,000**	19,393.84	6.642	20,961.44	7.179	1,567.60	0.537	8.08%
	90%	**328,500**	20,544.32	6.254	22,122.87	6.735	1,578.55	0.481	7.68%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GL	
		Existing	Proposed 2016
Customer Charge	($)	$25.00	$25.00
Demand Charge	($/kW)	$20.33	$23.29
Energy Charge - Non Summer	($/kWh)	$0.03620	$0.03650
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
600	**70%**	**306,600**	21,887.03	7.139	23,755.01	7.748	1,867.98	0.609	8.53%
	80%	**350,400**	23,267.61	6.640	25,148.73	7.177	1,881.12	0.537	8.08%
	90%	**394,200**	24,648.18	6.253	26,542.44	6.733	1,894.26	0.481	7.69%
800	**70%**	**408,800**	29,174.38	7.137	31,665.02	7.746	2,490.64	0.609	8.54%
	80%	**467,200**	31,015.14	6.639	33,523.30	7.175	2,508.16	0.537	8.09%
	90%	**525,600**	32,855.91	6.251	35,381.59	6.732	2,525.68	0.481	7.69%
1000	**70%**	**511,000**	36,461.72	7.135	39,575.02	7.745	3,113.30	0.609	8.54%
	80%	**584,000**	38,762.68	6.637	41,897.88	7.174	3,135.20	0.537	8.09%
	90%	**657,000**	41,063.64	6.250	44,220.74	6.731	3,157.10	0.481	7.69%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GV	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$21.60	$24.60
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	**20%**	**7,300**	1,421.01	19.466	1,574.01	21.562	153.00	2.096	10.77%
	30%	**10,950**	1,580.52	14.434	1,733.52	15.831	153.00	1.397	9.68%
	40%	**14,600**	1,740.02	11.918	1,893.02	12.966	153.00	1.048	8.79%
	50%	**18,250**	1,899.53	10.408	2,052.53	11.247	153.00	0.838	8.05%
	60%	**21,900**	2,059.03	9.402	2,212.03	10.101	153.00	0.699	7.43%
	70%	**25,550**	2,218.54	8.683	2,371.54	9.282	153.00	0.599	6.90%
	80%	**29,200**	2,378.04	8.144	2,531.04	8.668	153.00	0.524	6.43%
100	**20%**	**14,600**	2,820.02	19.315	3,123.02	21.391	303.00	2.075	10.74%
	30%	**21,900**	3,139.03	14.333	3,442.03	15.717	303.00	1.384	9.65%
	40%	**29,200**	3,458.04	11.843	3,761.04	12.880	303.00	1.038	8.76%
	50%	**36,500**	3,777.05	10.348	4,080.05	11.178	303.00	0.830	8.02%
	60%	**43,800**	4,096.06	9.352	4,399.06	10.044	303.00	0.692	7.40%
	70%	**51,100**	4,415.07	8.640	4,718.07	9.233	303.00	0.593	6.86%
	80%	**58,400**	4,734.08	8.106	5,037.08	8.625	303.00	0.519	6.40%
200	**20%**	**29,200**	5,618.04	19.240	6,221.04	21.305	603.00	2.065	10.73%
	30%	**43,800**	6,256.06	14.283	6,859.06	15.660	603.00	1.377	9.64%
	40%	**58,400**	6,894.08	11.805	7,497.08	12.837	603.00	1.033	8.75%
	50%	**73,000**	7,532.10	10.318	8,135.10	11.144	603.00	0.826	8.01%
	60%	**87,600**	8,170.12	9.327	8,773.12	10.015	603.00	0.688	7.38%
	70%	**102,200**	8,808.14	8.619	9,411.14	9.209	603.00	0.590	6.85%
	80%	**116,800**	9,446.16	8.087	10,049.16	8.604	603.00	0.516	6.38%

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(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GV	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$21.60	$24.60
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	20%	43,800	8,416.06	19.215	9,319.06	21.276	903.00	2.062	10.73%
	30%	65,700	9,373.09	14.266	10,276.09	15.641	903.00	1.374	9.63%
	40%	87,600	10,330.12	11.792	11,233.12	12.823	903.00	1.031	8.74%
	50%	109,500	11,287.15	10.308	12,190.15	11.133	903.00	0.825	8.00%
	60%	131,400	12,244.18	9.318	13,147.18	10.005	903.00	0.687	7.37%
	70%	153,300	13,201.21	8.611	14,104.21	9.200	903.00	0.589	6.84%
	80%	175,200	14,158.24	8.081	15,061.24	8.597	903.00	0.515	6.38%
400	20%	58,400	11,214.08	19.202	12,417.08	21.262	1,203.00	2.060	10.73%
	30%	87,600	12,490.12	14.258	13,693.12	15.631	1,203.00	1.373	9.63%
	40%	116,800	13,766.16	11.786	14,969.16	12.816	1,203.00	1.030	8.74%
	50%	146,000	15,042.20	10.303	16,245.20	11.127	1,203.00	0.824	8.00%
	60%	175,200	16,318.24	9.314	17,521.24	10.001	1,203.00	0.687	7.37%
	70%	204,400	17,594.28	8.608	18,797.28	9.196	1,203.00	0.589	6.84%
	80%	233,600	18,870.32	8.078	20,073.32	8.593	1,203.00	0.515	6.38%
500	20%	73,000	14,012.10	19.195	15,515.10	21.254	1,503.00	2.059	10.73%
	30%	109,500	15,607.15	14.253	17,110.15	15.626	1,503.00	1.373	9.63%
	40%	146,000	17,202.20	11.782	18,705.20	12.812	1,503.00	1.029	8.74%
	50%	182,500	18,797.25	10.300	20,300.25	11.123	1,503.00	0.824	8.00%
	60%	219,000	20,392.30	9.312	21,895.30	9.998	1,503.00	0.686	7.37%
	70%	255,500	21,987.35	8.606	23,490.35	9.194	1,503.00	0.588	6.84%
	80%	292,000	23,582.40	8.076	25,085.40	8.591	1,503.00	0.515	6.37%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GV	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$21.60	$24.60
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Load		Existing		Proposed 2016		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,300	1,341.59	18.378	1,494.59	20.474	153.00	2.096	11.40%
	30%	10,950	1,461.38	13.346	1,614.38	14.743	153.00	1.397	10.47%
	40%	14,600	1,581.17	10.830	1,734.17	11.878	153.00	1.048	9.68%
	50%	18,250	1,700.97	9.320	1,853.97	10.159	153.00	0.838	8.99%
	60%	21,900	1,820.76	8.314	1,973.76	9.013	153.00	0.699	8.40%
	70%	25,550	1,940.55	7.595	2,093.55	8.194	153.00	0.599	7.88%
	80%	29,200	2,060.34	7.056	2,213.34	7.580	153.00	0.524	7.43%
100	20%	14,600	2,661.17	18.227	2,964.17	20.303	303.00	2.075	11.39%
	30%	21,900	2,900.76	13.245	3,203.76	14.629	303.00	1.384	10.45%
	40%	29,200	3,140.34	10.755	3,443.34	11.792	303.00	1.038	9.65%
	50%	36,500	3,379.93	9.260	3,682.93	10.090	303.00	0.830	8.96%
	60%	43,800	3,619.52	8.264	3,922.52	8.956	303.00	0.692	8.37%
	70%	51,100	3,859.10	7.552	4,162.10	8.145	303.00	0.593	7.85%
	80%	58,400	4,098.69	7.018	4,401.69	7.537	303.00	0.519	7.39%
200	20%	29,200	5,300.34	18.152	5,903.34	20.217	603.00	2.065	11.38%
	30%	43,800	5,779.52	13.195	6,382.52	14.572	603.00	1.377	10.43%
	40%	58,400	6,258.69	10.717	6,861.69	11.749	603.00	1.033	9.63%
	50%	73,000	6,737.86	9.230	7,340.86	10.056	603.00	0.826	8.95%
	60%	87,600	7,217.03	8.239	7,820.03	8.927	603.00	0.688	8.36%
	70%	102,200	7,696.20	7.531	8,299.20	8.121	603.00	0.590	7.84%
	80%	116,800	8,175.38	6.999	8,778.38	7.516	603.00	0.516	7.38%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GV Existing	Rate Code GV Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$21.60	$24.60
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

Demand (kW)	Load Factor	Usage (kWh)	Existing Amount ($)	Existing Unit Cost (Cents/kWh)	Proposed 2016 Amount ($)	Proposed 2016 Unit Cost (Cents/kWh)	Difference Amount ($)	Difference Unit Cost (Cents/kWh)	Difference Percent (%)
300	20%	43,800	7,939.52	18.127	8,842.52	20.188	903.00	2.062	11.37%
	30%	65,700	8,658.27	13.178	9,561.27	14.553	903.00	1.374	10.43%
	40%	87,600	9,377.03	10.704	10,280.03	11.735	903.00	1.031	9.63%
	50%	109,500	10,095.79	9.220	10,998.79	10.045	903.00	0.825	8.94%
	60%	131,400	10,814.55	8.230	11,717.55	8.917	903.00	0.687	8.35%
	70%	153,300	11,533.31	7.523	12,436.31	8.112	903.00	0.589	7.83%
	80%	175,200	12,252.06	6.993	13,155.06	7.509	903.00	0.515	7.37%
400	20%	58,400	10,578.69	18.114	11,781.69	20.174	1,203.00	2.060	11.37%
	30%	87,600	11,537.03	13.170	12,740.03	14.543	1,203.00	1.373	10.43%
	40%	116,800	12,495.38	10.698	13,698.38	11.728	1,203.00	1.030	9.63%
	50%	146,000	13,453.72	9.215	14,656.72	10.039	1,203.00	0.824	8.94%
	60%	175,200	14,412.06	8.226	15,615.06	8.913	1,203.00	0.687	8.35%
	70%	204,400	15,370.41	7.520	16,573.41	8.108	1,203.00	0.589	7.83%
	80%	233,600	16,328.75	6.990	17,531.75	7.505	1,203.00	0.515	7.37%
500	20%	73,000	13,217.86	18.107	14,720.86	20.166	1,503.00	2.059	11.37%
	30%	109,500	14,415.79	13.165	15,918.79	14.538	1,503.00	1.373	10.43%
	40%	146,000	15,613.72	10.694	17,116.72	11.724	1,503.00	1.029	9.63%
	50%	182,500	16,811.65	9.212	18,314.65	10.035	1,503.00	0.824	8.94%
	60%	219,000	18,009.58	8.224	19,512.58	8.910	1,503.00	0.686	8.35%
	70%	255,500	19,207.51	7.518	20,710.51	8.106	1,503.00	0.588	7.83%
	80%	292,000	20,405.44	6.988	21,908.44	7.503	1,503.00	0.515	7.37%

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Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GT	
		Existing	Proposed 2016
Customer Charge	($)	$30.00000	$30.00000
Demand Charge - On-Peak	($/kW)	$21.95000	$25.23000
Demand Charge - Off-Peak	($/kW)	$13.60000	$13.28000
Energy Charge - Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,390	1,045.34	14.145	1,057.16	14.305	11.82	0.160	1.13%
	30%	11,085	1,180.75	10.652	1,192.57	10.758	11.82	0.107	1.00%
	40%	14,780	1,316.16	8.905	1,327.98	8.985	11.82	0.080	0.90%
	50%	18,475	1,451.56	7.857	1,463.39	7.921	11.82	0.064	0.81%
	60%	22,170	1,586.97	7.158	1,598.79	7.212	11.82	0.053	0.74%
	70%	25,865	1,722.38	6.659	1,734.20	6.705	11.82	0.046	0.69%
	80%	29,560	1,857.78	6.285	1,869.61	6.325	11.82	0.040	0.64%
100	20%	14,780	2,060.69	13.942	2,084.33	14.102	23.64	0.160	1.15%
	30%	22,170	2,331.50	10.516	2,355.14	10.623	23.64	0.107	1.01%
	40%	29,560	2,602.31	8.803	2,625.96	8.883	23.64	0.080	0.91%
	50%	36,950	2,873.13	7.776	2,896.77	7.840	23.64	0.064	0.82%
	60%	44,340	3,143.94	7.091	3,167.58	7.144	23.64	0.053	0.75%
	70%	51,730	3,414.76	6.601	3,438.40	6.647	23.64	0.046	0.69%
	80%	59,120	3,685.57	6.234	3,709.21	6.274	23.64	0.040	0.64%
200	20%	29,560	4,091.37	13.841	4,138.66	14.001	47.28	0.160	1.16%
	30%	44,340	4,633.00	10.449	4,680.29	10.555	47.28	0.107	1.02%
	40%	59,120	5,174.63	8.753	5,221.91	8.833	47.28	0.080	0.91%
	50%	73,900	5,716.26	7.735	5,763.54	7.799	47.28	0.064	0.83%
	60%	88,680	6,257.88	7.057	6,305.17	7.110	47.28	0.053	0.76%
	70%	103,460	6,799.51	6.572	6,846.80	6.618	47.28	0.046	0.70%
	80%	118,240	7,341.14	6.209	7,388.42	6.249	47.28	0.040	0.64%

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		Rate Code GT	
		Existing	Proposed 2016
Customer Charge	($)	$30.00000	$30.00000
Demand Charge - On-Peak	($/kW)	$21.95000	$25.23000
Demand Charge - Off-Peak	($/kW)	$13.60000	$13.28000
Energy Charge - Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand	Load Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	20%	44,340	6,122.06	13.807	6,192.99	13.967	70.93	0.160	1.16%
	30%	66,510	6,934.50	10.426	7,005.43	10.533	70.93	0.107	1.02%
	40%	88,680	7,746.94	8.736	7,817.87	8.816	70.93	0.080	0.92%
	50%	110,850	8,559.38	7.722	8,630.31	7.786	70.93	0.064	0.83%
	60%	133,020	9,371.83	7.045	9,442.75	7.099	70.93	0.053	0.76%
	70%	155,190	10,184.27	6.562	10,255.19	6.608	70.93	0.046	0.70%
	80%	177,360	10,996.71	6.200	11,067.64	6.240	70.93	0.040	0.64%
400	20%	59,120	8,152.75	13.790	8,247.31	13.950	94.57	0.160	1.16%
	30%	88,680	9,236.00	10.415	9,330.57	10.522	94.57	0.107	1.02%
	40%	118,240	10,319.26	8.727	10,413.83	8.807	94.57	0.080	0.92%
	50%	147,800	11,402.51	7.715	11,497.08	7.779	94.57	0.064	0.83%
	60%	177,360	12,485.77	7.040	12,580.34	7.093	94.57	0.053	0.76%
	70%	206,920	13,569.02	6.558	13,663.59	6.603	94.57	0.046	0.70%
	80%	236,480	14,652.28	6.196	14,746.85	6.236	94.57	0.040	0.65%
500	20%	73,900	10,183.43	13.780	10,301.64	13.940	118.21	0.160	1.16%
	30%	110,850	11,537.50	10.408	11,655.71	10.515	118.21	0.107	1.02%
	40%	147,800	12,891.57	8.722	13,009.78	8.802	118.21	0.080	0.92%
	50%	184,750	14,245.64	7.711	14,363.85	7.775	118.21	0.064	0.83%
	60%	221,700	15,599.71	7.036	15,717.92	7.090	118.21	0.053	0.76%
	70%	258,650	16,953.78	6.555	17,071.99	6.600	118.21	0.046	0.70%
	80%	295,600	18,307.85	6.193	18,426.06	6.233	118.21	0.040	0.65%

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		Rate Code GT	
		Existing	Proposed 2016
Customer Charge	($)	$30.00	$30.00
Demand Charge - On-Peak	($/kW)	$21.95	$25.23
Demand Charge - Off-Peak	($/kW)	$13.60	$13.28
Energy Charge - Non-Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Non-Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

			Existing		Proposed 2016		Difference		
Demand	Load Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	**20%**	**7,390**	1,019.52	13.796	1,024.85	13.868	5.33	0.072	0.52%
	30%	**11,085**	1,149.55	10.370	1,154.88	10.418	5.33	0.048	0.46%
	40%	**14,780**	1,279.58	8.657	1,284.91	8.694	5.33	0.036	0.42%
	50%	**18,475**	1,409.60	7.630	1,414.93	7.659	5.33	0.029	0.38%
	60%	**22,170**	1,539.63	6.945	1,544.96	6.969	5.33	0.024	0.35%
	70%	**25,865**	1,669.66	6.455	1,674.99	6.476	5.33	0.021	0.32%
	80%	**29,560**	1,799.68	6.088	1,805.01	6.106	5.33	0.018	0.30%
100	**20%**	**14,780**	2,009.05	13.593	2,019.71	13.665	10.66	0.072	0.53%
	30%	**22,170**	2,269.10	10.235	2,279.76	10.283	10.66	0.048	0.47%
	40%	**29,560**	2,529.15	8.556	2,539.81	8.592	10.66	0.036	0.42%
	50%	**36,950**	2,789.21	7.549	2,799.86	7.577	10.66	0.029	0.38%
	60%	**44,340**	3,049.26	6.877	3,059.92	6.901	10.66	0.024	0.35%
	70%	**51,730**	3,309.31	6.397	3,319.97	6.418	10.66	0.021	0.32%
	80%	**59,120**	3,569.37	6.037	3,580.02	6.056	10.66	0.018	0.30%
200	**20%**	**29,560**	3,988.10	13.492	4,009.41	13.564	21.32	0.072	0.53%
	30%	**44,340**	4,508.20	10.167	4,529.52	10.215	21.32	0.048	0.47%
	40%	**59,120**	5,028.31	8.505	5,049.62	8.541	21.32	0.036	0.42%
	50%	**73,900**	5,548.41	7.508	5,569.73	7.537	21.32	0.029	0.38%
	60%	**88,680**	6,068.52	6.843	6,089.84	6.867	21.32	0.024	0.35%
	70%	**103,460**	6,588.63	6.368	6,609.94	6.389	21.32	0.021	0.32%
	80%	**118,240**	7,108.73	6.012	7,130.05	6.030	21.32	0.018	0.30%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 General Service Rates

		Rate Code GT	
		Existing	Proposed 2016
Customer Charge	($)	$30.00	$30.00
Demand Charge - On-Peak	($/kW)	$21.95	$25.23
Demand Charge - Off-Peak	($/kW)	$13.60	$13.28
Energy Charge - Non-Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Non-Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	**20%**	**44,340**	5,967.14	13.458	5,999.12	13.530	31.97	0.072	0.54%
	30%	**66,510**	6,747.30	10.145	6,779.28	10.193	31.97	0.048	0.47%
	40%	**88,680**	7,527.46	8.488	7,559.43	8.524	31.97	0.036	0.42%
	50%	**110,850**	8,307.62	7.494	8,339.59	7.523	31.97	0.029	0.38%
	60%	**133,020**	9,087.78	6.832	9,119.75	6.856	31.97	0.024	0.35%
	70%	**155,190**	9,867.94	6.359	9,899.91	6.379	31.97	0.021	0.32%
	80%	**177,360**	10,648.10	6.004	10,680.07	6.022	31.97	0.018	0.30%
400	**20%**	**59,120**	7,946.19	13.441	7,988.82	13.513	42.63	0.072	0.54%
	30%	**88,680**	8,986.40	10.134	9,029.03	10.182	42.63	0.048	0.47%
	40%	**118,240**	10,026.62	8.480	10,069.25	8.516	42.63	0.036	0.43%
	50%	**147,800**	11,066.83	7.488	11,109.46	7.517	42.63	0.029	0.39%
	60%	**177,360**	12,107.04	6.826	12,149.67	6.850	42.63	0.024	0.35%
	70%	**206,920**	13,147.25	6.354	13,189.88	6.374	42.63	0.021	0.32%
	80%	**236,480**	14,187.47	5.999	14,230.10	6.017	42.63	0.018	0.30%
500	**20%**	**73,900**	9,925.24	13.431	9,978.53	13.503	53.29	0.072	0.54%
	30%	**110,850**	11,225.51	10.127	11,278.79	10.175	53.29	0.048	0.47%
	40%	**147,800**	12,525.77	8.475	12,579.06	8.511	53.29	0.036	0.43%
	50%	**184,750**	13,826.04	7.484	13,879.32	7.512	53.29	0.029	0.39%
	60%	**221,700**	15,126.30	6.823	15,179.59	6.847	53.29	0.024	0.35%
	70%	**258,650**	16,426.57	6.351	16,479.85	6.371	53.29	0.021	0.32%
	80%	**295,600**	17,726.83	5.997	17,780.12	6.015	53.29	0.018	0.30%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Temporary Service Rate

		Rate Code TP	
		Existing	Proposed 2016
Customer Charge	($)	$18.00	$21.00
Energy Charge - Summer	($/kWh)	$0.12540	$0.14060
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	54.48	18.160	62.04	20.680	7.56	2.520	13.88%
400	66.64	16.660	75.72	18.930	9.08	2.270	13.63%
500	78.80	15.760	89.40	17.880	10.60	2.120	13.45%
750	109.20	14.560	123.60	16.480	14.40	1.920	13.19%
1,000	139.60	13.960	157.80	15.780	18.20	1.820	13.04%
2,000	261.20	13.060	294.60	14.730	33.40	1.670	12.79%
3,000	382.80	12.760	431.40	14.380	48.60	1.620	12.70%
4,000	504.40	12.610	568.20	14.205	63.80	1.595	12.65%
5,000	626.00	12.520	705.00	14.100	79.00	1.580	12.62%
6,000	747.60	12.460	841.80	14.030	94.20	1.570	12.60%
7,000	869.20	12.417	978.60	13.980	109.40	1.563	12.59%
8,000	990.80	12.385	1,115.40	13.943	124.60	1.558	12.58%
9,000	1,112.40	12.360	1,252.20	13.913	139.80	1.553	12.57%
10,000	1,234.00	12.340	1,389.00	13.890	155.00	1.550	12.56%
11,000	1,355.60	12.324	1,525.80	13.871	170.20	1.547	12.56%
12,000	1,477.20	12.310	1,662.60	13.855	185.40	1.545	12.55%
13,000	1,598.80	12.298	1,799.40	13.842	200.60	1.543	12.55%
14,000	1,720.40	12.289	1,936.20	13.830	215.80	1.541	12.54%
15,000	1,842.00	12.280	2,073.00	13.820	231.00	1.540	12.54%
20,000	2,450.00	12.250	2,757.00	13.785	307.00	1.535	12.53%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Temporary Service Rate

		Rate Code TP	
		Existing	Proposed 2016
Customer Charge	($)	$18.00	$21.00
Energy Charge - Non Summer	($/kWh)	$0.11540	$0.12060
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

	Existing		Proposed 2016		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	51.22	17.072	55.78	18.592	4.56	1.520	8.90%
400	62.29	15.572	67.37	16.842	5.08	1.270	8.16%
500	73.36	14.672	78.96	15.792	5.60	1.120	7.63%
750	101.04	13.472	107.94	14.392	6.90	0.920	6.83%
1,000	128.72	12.872	136.92	13.692	8.20	0.820	6.37%
2,000	239.44	11.972	252.84	12.642	13.40	0.670	5.60%
3,000	350.16	11.672	368.76	12.292	18.60	0.620	5.31%
4,000	460.88	11.522	484.68	12.117	23.80	0.595	5.16%
5,000	571.60	11.432	600.60	12.012	29.00	0.580	5.07%
6,000	682.32	11.372	716.52	11.942	34.20	0.570	5.01%
7,000	793.04	11.329	832.44	11.892	39.40	0.563	4.97%
8,000	903.76	11.297	948.36	11.855	44.60	0.557	4.93%
9,000	1,014.48	11.272	1,064.28	11.825	49.80	0.553	4.91%
10,000	1,125.20	11.252	1,180.20	11.802	55.00	0.550	4.89%
11,000	1,235.92	11.236	1,296.12	11.783	60.20	0.547	4.87%
12,000	1,346.64	11.222	1,412.04	11.767	65.40	0.545	4.86%
13,000	1,457.36	11.210	1,527.96	11.754	70.60	0.543	4.84%
14,000	1,568.08	11.201	1,643.88	11.742	75.80	0.541	4.83%
15,000	1,678.80	11.192	1,759.80	11.732	81.00	0.540	4.82%
20,000	2,232.40	11.162	2,339.40	11.697	107.00	0.535	4.79%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Transition Adjustment

		Rate Code TA	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$3.88	$9.75
Energy Charge - Summer	($/kWh)	$0.08690	$0.07563
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	822.63	11.269	1,036.69	14.201	214.06	2.932	26.02%
	30%	10,950	1,125.84	10.282	1,298.85	11.862	173.01	1.580	15.37%
	40%	14,600	1,429.16	9.789	1,561.02	10.692	131.86	0.903	9.23%
	50%	18,250	1,732.47	9.493	1,823.18	9.990	90.71	0.497	5.24%
	60%	21,900	2,035.79	9.296	2,085.34	9.522	49.55	0.226	2.43%
	70%	25,550	2,339.10	9.155	2,347.50	9.188	8.40	0.033	0.36%
	80%	29,200	2,642.42	9.049	2,609.66	8.937	(32.76)	(0.112)	-1.24%
100	20%	14,600	1,623.05	11.117	2,048.39	14.030	425.34	2.913	26.21%
	30%	21,900	2,229.68	10.181	2,572.71	11.748	343.03	1.566	15.38%
	40%	29,200	2,836.31	9.713	3,097.03	10.606	260.72	0.893	9.19%
	50%	36,500	3,442.94	9.433	3,621.35	9.922	178.41	0.489	5.18%
	60%	43,800	4,049.57	9.246	4,145.68	9.465	96.11	0.219	2.37%
	70%	51,100	4,656.20	9.112	4,670.00	9.139	13.80	0.027	0.30%
	80%	58,400	5,262.83	9.012	5,194.32	8.894	(68.51)	(0.117)	-1.30%
200	20%	29,200	3,224.10	11.041	4,071.77	13.944	847.67	2.903	26.29%
	30%	43,800	4,437.36	10.131	5,120.42	11.690	683.05	1.559	15.39%
	40%	58,400	5,650.62	9.676	6,169.06	10.563	518.44	0.888	9.17%
	50%	73,000	6,863.88	9.403	7,217.71	9.887	353.83	0.485	5.15%
	60%	87,600	8,077.14	9.220	8,266.35	9.436	189.21	0.216	2.34%
	70%	102,200	9,290.40	9.090	9,315.00	9.114	24.59	0.024	0.26%
	80%	116,800	10,503.66	8.993	10,363.64	8.873	(140.02)	(0.120)	-1.33%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Transition Adjustment

		Rate Code TA	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$3.88	$9.75
Energy Charge - Summer	($/kWh)	$0.08690	$0.07563
Demand Sales Adjustment	($/kWh)	-$0.00210	-$0.00210
Fuel Adjustment	($/kWh)	-$0.00170	-$0.00170

Demand	Load Factor	Usage	Existing Amount	Existing Unit Cost	Proposed 2016 Amount	Proposed 2016 Unit Cost	Difference Amount	Difference Unit Cost	Difference Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	20%	43,800	4,825.15	11.016	6,095.16	13.916	1,270.01	2.900	26.32%
	30%	65,700	6,645.04	10.114	7,668.12	11.671	1,023.08	1.557	15.40%
	40%	87,600	8,464.93	9.663	9,241.09	10.549	776.16	0.886	9.17%
	50%	109,500	10,284.82	9.393	10,814.06	9.876	529.24	0.483	5.15%
	60%	131,400	12,104.71	9.212	12,387.03	9.427	282.32	0.215	2.33%
	70%	153,300	13,924.60	9.083	13,959.99	9.106	35.39	0.023	0.25%
	80%	175,200	15,744.49	8.987	15,532.96	8.866	(211.53)	(0.121)	-1.34%
400	20%	58,400	6,426.20	11.004	8,118.54	13.902	1,692.34	2.898	26.34%
	30%	87,600	8,852.72	10.106	10,215.83	11.662	1,363.11	1.556	15.40%
	40%	116,800	11,279.24	9.657	12,313.12	10.542	1,033.88	0.885	9.17%
	50%	146,000	13,705.76	9.388	14,410.41	9.870	704.65	0.483	5.14%
	60%	175,200	16,132.28	9.208	16,507.70	9.422	375.42	0.214	2.33%
	70%	204,400	18,558.80	9.080	18,604.99	9.102	46.19	0.023	0.25%
	80%	233,600	20,985.32	8.983	20,702.28	8.862	(283.04)	(0.121)	-1.35%
500	20%	73,000	8,027.25	10.996	10,141.93	13.893	2,114.68	2.897	26.34%
	30%	109,500	11,060.40	10.101	12,763.54	11.656	1,703.14	1.555	15.40%
	40%	146,000	14,093.55	9.653	15,385.15	10.538	1,291.60	0.885	9.16%
	50%	182,500	17,126.70	9.384	18,006.76	9.867	880.06	0.482	5.14%
	60%	219,000	20,159.85	9.205	20,628.38	9.419	468.52	0.214	2.32%
	70%	255,500	23,193.00	9.077	23,249.99	9.100	56.99	0.022	0.25%
	80%	292,000	26,226.15	8.982	25,871.60	8.860	(354.55)	(0.121)	-1.35%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing GA and Proposed 2013 Transition Adjustment

		Rate Code TA	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$3.88	$9.75
Energy Charge - Nonsummer	($/kWh)	$0.07690	$0.06563
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	743.07	10.179	957.37	13.115	214.30	2.936	28.84%
	30%	10,950	1,006.67	9.193	1,179.82	10.775	173.15	1.581	17.20%
	40%	14,600	1,270.28	8.701	1,402.27	9.605	131.99	0.904	10.39%
	50%	18,250	1,533.88	8.405	1,624.72	8.903	90.84	0.498	5.92%
	60%	21,900	1,797.48	8.208	1,847.17	8.435	49.69	0.227	2.76%
	70%	25,550	2,061.09	8.067	2,069.62	8.100	8.53	0.033	0.41%
	80%	29,200	2,324.69	7.961	2,292.07	7.850	(32.62)	(0.112)	-1.40%
100	20%	14,600	1,464.14	10.028	1,889.75	12.943	425.60	2.915	29.07%
	30%	21,900	1,991.35	9.093	2,334.65	10.660	343.30	1.568	17.24%
	40%	29,200	2,518.56	8.625	2,779.54	9.519	260.99	0.894	10.36%
	50%	36,500	3,045.76	8.345	3,224.44	8.834	178.68	0.490	5.87%
	60%	43,800	3,572.97	8.157	3,669.34	8.377	96.37	0.220	2.70%
	70%	51,100	4,100.17	8.024	4,114.24	8.051	14.07	0.028	0.34%
	80%	58,400	4,627.38	7.924	4,559.14	7.807	(68.24)	(0.117)	-1.47%
200	20%	29,200	2,906.29	9.953	3,754.49	12.858	848.21	2.905	29.19%
	30%	43,800	3,960.70	9.043	4,644.29	10.603	683.59	1.561	17.26%
	40%	58,400	5,015.11	8.588	5,534.09	9.476	518.98	0.889	10.35%
	50%	73,000	6,069.52	8.314	6,423.89	8.800	354.36	0.485	5.84%
	60%	87,600	7,123.93	8.132	7,313.68	8.349	189.75	0.217	2.66%
	70%	102,200	8,178.35	8.002	8,203.48	8.027	25.13	0.025	0.31%
	80%	116,800	9,232.76	7.905	9,093.28	7.785	(139.48)	(0.119)	-1.51%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing GA and Proposed 2013 Transition Adjustment

		Rate Code TA	
		Existing	Proposed 2016
Customer Charge	($)	$22.00	$25.00
Demand Charge	($/kW)	$3.88	$9.75
Energy Charge - Nonsummer	($/kWh)	$0.07690	$0.06563
Demand Sales Adjustment	($/kWh)	-$0.00269	-$0.00269
Fuel Adjustment	($/kWh)	-$0.00199	-$0.00199

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	20%	43,800	4,348.43	9.928	5,619.24	12.829	1,270.81	2.901	29.22%
	30%	65,700	5,930.05	9.026	6,953.94	10.584	1,023.89	1.558	17.27%
	40%	87,600	7,511.67	8.575	8,288.63	9.462	776.97	0.887	10.34%
	50%	109,500	9,093.28	8.304	9,623.33	8.788	530.04	0.484	5.83%
	60%	131,400	10,674.90	8.124	10,958.02	8.339	283.12	0.215	2.65%
	70%	153,300	12,256.52	7.995	12,292.72	8.019	36.20	0.024	0.30%
	80%	175,200	13,838.14	7.898	13,627.41	7.778	(210.72)	(0.120)	-1.52%
400	20%	58,400	5,790.57	9.915	7,483.99	12.815	1,693.42	2.900	29.24%
	30%	87,600	7,899.40	9.018	9,263.58	10.575	1,364.19	1.557	17.27%
	40%	116,800	10,008.22	8.569	11,043.18	9.455	1,034.96	0.886	10.34%
	50%	146,000	12,117.04	8.299	12,822.77	8.783	705.73	0.483	5.82%
	60%	175,200	14,225.87	8.120	14,602.36	8.335	376.50	0.215	2.65%
	70%	204,400	16,334.69	7.992	16,381.96	8.015	47.27	0.023	0.29%
	80%	233,600	18,443.52	7.895	18,161.55	7.775	(281.96)	(0.121)	-1.53%
500	20%	73,000	7,232.72	9.908	9,348.74	12.806	2,116.02	2.899	29.26%
	30%	109,500	9,868.75	9.013	11,573.23	10.569	1,704.48	1.557	17.27%
	40%	146,000	12,504.78	8.565	13,797.72	9.450	1,292.95	0.886	10.34%
	50%	182,500	15,140.81	8.296	16,022.21	8.779	881.41	0.483	5.82%
	60%	219,000	17,776.84	8.117	18,246.71	8.332	469.87	0.215	2.64%
	70%	255,500	20,412.87	7.989	20,471.20	8.012	58.33	0.023	0.29%
	80%	292,000	23,048.90	7.893	22,695.69	7.772	(353.20)	(0.121)	-1.53%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Industrial Service Rate

		Rate Code L	
		Existing	Proposed 2016
Customer Charge	($)	$3,000.00	$3,400.00
Base Demand First 300 kW	($)	$4,986.00	$7,332.00
Additional Demand Charge	($/kW)	$16.62	$18.80
Energy Charge - On-Peak	($/kWh)	$0.05750	$0.05750
Energy Charge - Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kW)	-$0.96861	-$0.96861
Fuel Adjustment	($/kWh)	-$0.00162	-$0.00162

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
1,000	**20%**	**146,000**	24,384.85	16.702	28,656.85	19.628	4,272.00	2.926	17.52%
	30%	**219,000**	27,106.29	12.377	31,378.29	14.328	4,272.00	1.951	15.76%
	40%	**292,000**	29,827.73	10.215	34,099.73	11.678	4,272.00	1.463	14.32%
	50%	**365,000**	32,549.17	8.918	36,821.17	10.088	4,272.00	1.170	13.12%
	60%	**438,000**	35,270.61	8.053	39,542.61	9.028	4,272.00	0.975	12.11%
	70%	**511,000**	37,992.05	7.435	42,264.05	8.271	4,272.00	0.836	11.24%
	80%	**584,000**	40,713.49	6.971	44,985.49	7.703	4,272.00	0.732	10.49%
1,500	**20%**	**219,000**	34,931.99	15.951	40,293.99	18.399	5,362.00	2.448	15.35%
	30%	**328,500**	39,014.15	11.876	44,376.15	13.509	5,362.00	1.632	13.74%
	40%	**438,000**	43,096.31	9.839	48,458.31	11.064	5,362.00	1.224	12.44%
	50%	**547,500**	47,178.47	8.617	52,540.47	9.596	5,362.00	0.979	11.37%
	60%	**657,000**	51,260.63	7.802	56,622.63	8.618	5,362.00	0.816	10.46%
	70%	**766,500**	55,342.79	7.220	60,704.79	7.920	5,362.00	0.700	9.69%
	80%	**876,000**	59,424.95	6.784	64,786.95	7.396	5,362.00	0.612	9.02%
2,000	**20%**	**292,000**	45,479.12	15.575	51,931.12	17.785	6,452.00	2.210	14.19%
	30%	**438,000**	50,922.00	11.626	57,374.00	13.099	6,452.00	1.473	12.67%
	40%	**584,000**	56,364.88	9.652	62,816.88	10.756	6,452.00	1.105	11.45%
	50%	**730,000**	61,807.76	8.467	68,259.76	9.351	6,452.00	0.884	10.44%
	60%	**876,000**	67,250.64	7.677	73,702.64	8.414	6,452.00	0.737	9.59%
	70%	**1,022,000**	72,693.52	7.113	79,145.52	7.744	6,452.00	0.631	8.88%
	80%	**1,168,000**	78,136.40	6.690	84,588.40	7.242	6,452.00	0.552	8.26%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Industrial Service Rate

		Rate Code L	
		Existing	Proposed 2016
Customer Charge	($)	$3,000.00	$3,400.00
Base Demand First 300 kW	($)	$4,986.00	$7,332.00
Additional Demand Charge	($/kW)	$16.62	$18.80
Energy Charge - On-Peak	($/kWh)	$0.05750	$0.05750
Energy Charge - Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kW)	-$0.96861	-$0.96861
Fuel Adjustment	($/kWh)	-$0.00162	-$0.00162

	Load		Existing		Proposed 2016		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
3,000	**20%**	**438,000**	66,573.39	15.199	75,205.39	17.170	8,632.00	1.971	12.97%
	30%	**657,000**	74,737.71	11.376	83,369.71	12.689	8,632.00	1.314	11.55%
	40%	**876,000**	82,902.03	9.464	91,534.03	10.449	8,632.00	0.985	10.41%
	50%	**1,095,000**	91,066.35	8.317	99,698.35	9.105	8,632.00	0.788	9.48%
	60%	**1,314,000**	99,230.67	7.552	107,862.67	8.209	8,632.00	0.657	8.70%
	70%	**1,533,000**	107,394.99	7.006	116,026.99	7.569	8,632.00	0.563	8.04%
	80%	**1,752,000**	115,559.31	6.596	124,191.31	7.089	8,632.00	0.493	7.47%
4,000	**20%**	**584,000**	87,667.66	15.012	98,479.66	16.863	10,812.00	1.851	12.33%
	30%	**876,000**	98,553.42	11.250	109,365.42	12.485	10,812.00	1.234	10.97%
	40%	**1,168,000**	109,439.18	9.370	120,251.18	10.295	10,812.00	0.926	9.88%
	50%	**1,460,000**	120,324.94	8.241	131,136.94	8.982	10,812.00	0.741	8.99%
	60%	**1,752,000**	131,210.70	7.489	142,022.70	8.106	10,812.00	0.617	8.24%
	70%	**2,044,000**	142,096.46	6.952	152,908.46	7.481	10,812.00	0.529	7.61%
	80%	**2,336,000**	152,982.22	6.549	163,794.22	7.012	10,812.00	0.463	7.07%
5,000	**20%**	**730,000**	108,761.93	14.899	121,753.93	16.679	12,992.00	1.780	11.95%
	30%	**1,095,000**	122,369.13	11.175	135,361.13	12.362	12,992.00	1.186	10.62%
	40%	**1,460,000**	135,976.33	9.313	148,968.33	10.203	12,992.00	0.890	9.55%
	50%	**1,825,000**	149,583.53	8.196	162,575.53	8.908	12,992.00	0.712	8.69%
	60%	**2,190,000**	163,190.73	7.452	176,182.73	8.045	12,992.00	0.593	7.96%
	70%	**2,555,000**	176,797.93	6.920	189,789.93	7.428	12,992.00	0.508	7.35%
	80%	**2,920,000**	190,405.13	6.521	203,397.13	6.966	12,992.00	0.445	6.82%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Municipal Service Rate

		Rate Code ML	
		Existing	Proposed 2016
Customer Charge	($)	$1,200.00	$1,400.00
Base Demand First 1,000 kW	($)	$16,650.00	$17,240.00
Additional Demand Charge	($/kW)	$16.65	$17.24
Energy Charge	($/kWh)	$0.03890	$0.04100
Demand Sales Adjustment	($/kW)	-$0.96861	-$0.96861
Fuel Adjustment	($/kWh)	-$0.00162	-$0.00162

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
5,000	**20%**	**730,000**	106,821.35	14.633	111,504.35	15.275	4,683.00	0.642	4.38%
	30%	**1,095,000**	120,428.55	10.998	125,878.05	11.496	5,449.50	0.498	4.53%
	40%	**1,460,000**	134,035.75	9.181	140,251.75	9.606	6,216.00	0.426	4.64%
	50%	**1,825,000**	147,642.95	8.090	154,625.45	8.473	6,982.50	0.383	4.73%
	60%	**2,190,000**	161,250.15	7.363	168,999.15	7.717	7,749.00	0.354	4.81%
10,000	**20%**	**1,460,000**	212,442.70	14.551	221,608.70	15.179	9,166.00	0.628	4.31%
	30%	**2,190,000**	239,657.10	10.943	250,356.10	11.432	10,699.00	0.489	4.46%
	40%	**2,920,000**	266,871.50	9.139	279,103.50	9.558	12,232.00	0.419	4.58%
	50%	**3,650,000**	294,085.90	8.057	307,850.90	8.434	13,765.00	0.377	4.68%
	60%	**4,380,000**	321,300.30	7.336	336,598.30	7.685	15,298.00	0.349	4.76%
15,000	**20%**	**2,190,000**	318,064.05	14.523	331,713.05	15.147	13,649.00	0.623	4.29%
	30%	**3,285,000**	358,885.65	10.925	374,834.15	11.410	15,948.50	0.485	4.44%
	40%	**4,380,000**	399,707.25	9.126	417,955.25	9.542	18,248.00	0.417	4.57%
	50%	**5,475,000**	440,528.85	8.046	461,076.35	8.421	20,547.50	0.375	4.66%
	60%	**6,570,000**	481,350.45	7.326	504,197.45	7.674	22,847.00	0.348	4.75%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Existing and Proposed 2016 Municipal Service Rate

		Rate Code ML	
		Existing	Proposed 2016
Customer Charge	($)	$1,200.00	$1,400.00
Base Demand First 1,000 kW	($)	$16,650.00	$17,240.00
Additional Demand Charge	($/kW)	$16.65	$17.24
Energy Charge	($/kWh)	$0.03890	$0.04100
Demand Sales Adjustment	($/kW)	-$0.96861	-$0.96861
Fuel Adjustment	($/kWh)	-$0.00162	-$0.00162

			Existing		Proposed 2016		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
20,000	**20%**	**2,920,000**	423,685.40	14.510	441,817.40	15.131	18,132.00	0.621	4.28%
	30%	**4,380,000**	478,114.20	10.916	499,312.20	11.400	21,198.00	0.484	4.43%
	40%	**5,840,000**	532,543.00	9.119	556,807.00	9.534	24,264.00	0.415	4.56%
	50%	**7,300,000**	586,971.80	8.041	614,301.80	8.415	27,330.00	0.374	4.66%
	60%	**8,760,000**	641,400.60	7.322	671,796.60	7.669	30,396.00	0.347	4.74%
25,000	**20%**	**3,650,000**	529,306.75	14.502	551,921.75	15.121	22,615.00	0.620	4.27%
	30%	**5,475,000**	597,342.75	10.910	623,790.25	11.393	26,447.50	0.483	4.43%
	40%	**7,300,000**	665,378.75	9.115	695,658.75	9.530	30,280.00	0.415	4.55%
	50%	**9,125,000**	733,414.75	8.037	767,527.25	8.411	34,112.50	0.374	4.65%
	60%	**10,950,000**	801,450.75	7.319	839,395.75	7.666	37,945.00	0.347	4.73%
30,000	**20%**	**4,380,000**	634,928.10	14.496	662,026.10	15.115	27,098.00	0.619	4.27%
	30%	**6,570,000**	716,571.30	10.907	748,268.30	11.389	31,697.00	0.482	4.42%
	40%	**8,760,000**	798,214.50	9.112	834,510.50	9.526	36,296.00	0.414	4.55%
	50%	**10,950,000**	879,857.70	8.035	920,752.70	8.409	40,895.00	0.373	4.65%
	60%	**13,140,000**	961,500.90	7.317	1,006,994.90	7.664	45,494.00	0.346	4.73%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Residential Service Rates and Proposed 2017 Residential Service Rates

		Rate Code RG	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$17.00	$19.50
Energy Charge - Summer	($/kWh)	$0.12020	$0.11970
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Proposed 2016		Proposed 2017		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	52.64	17.547	54.99	18.330	2.35	0.783	4.46%
400	64.52	16.130	66.82	16.705	2.30	0.575	3.56%
500	76.40	15.280	78.65	15.730	2.25	0.450	2.95%
600	88.28	14.713	90.48	15.080	2.20	0.367	2.49%
700	100.16	14.309	102.31	14.616	2.15	0.307	2.15%
800	112.04	14.005	114.14	14.268	2.10	0.262	1.87%
900	123.92	13.769	125.97	13.997	2.05	0.228	1.65%
1,000	135.80	13.580	137.80	13.780	2.00	0.200	1.47%
1,100	147.68	13.425	149.63	13.603	1.95	0.177	1.32%
1,200	159.56	13.297	161.46	13.455	1.90	0.158	1.19%
1,300	171.44	13.188	173.29	13.330	1.85	0.142	1.08%
1,400	183.32	13.094	185.12	13.223	1.80	0.129	0.98%
1,500	195.20	13.013	196.95	13.130	1.75	0.117	0.90%
2,000	254.60	12.730	256.10	12.805	1.50	0.075	0.59%
2,500	314.00	12.560	315.25	12.610	1.25	0.050	0.40%
3,000	373.40	12.447	374.40	12.480	1.00	0.033	0.27%
4,000	492.20	12.305	492.70	12.318	0.50	0.013	0.10%
5,000	611.00	12.220	611.00	12.220	0.00	0.000	0.00%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Residential Service Rates and Proposed 2017 Residential Service Rates

		Rate Code RG	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$17.00	$19.50
Energy Charge - Non Summer	($/kWh)	$0.10020	$0.09970
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Proposed 2016		Proposed 2017		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	45.84	15.280	48.19	16.063	2.35	0.783	5.13%
400	55.45	13.863	57.75	14.438	2.30	0.575	4.15%
500	65.07	13.013	67.32	13.463	2.25	0.450	3.46%
600	74.68	12.446	76.88	12.813	2.20	0.367	2.95%
700	84.29	12.042	86.44	12.349	2.15	0.307	2.55%
800	93.90	11.738	96.00	12.001	2.10	0.262	2.24%
900	103.52	11.502	105.57	11.730	2.05	0.228	1.98%
1,000	113.13	11.313	115.13	11.513	2.00	0.200	1.77%
1,100	122.74	11.158	124.69	11.336	1.95	0.177	1.59%
1,200	132.36	11.030	134.26	11.188	1.90	0.158	1.44%
1,300	141.97	10.921	143.82	11.063	1.85	0.142	1.30%
1,400	151.58	10.827	153.38	10.956	1.80	0.129	1.19%
1,500	161.20	10.746	162.95	10.863	1.75	0.117	1.09%
2,000	209.26	10.463	210.76	10.538	1.50	0.075	0.72%
2,500	257.33	10.293	258.58	10.343	1.25	0.050	0.49%
3,000	305.39	10.180	306.39	10.213	1.00	0.033	0.33%
4,000	401.52	10.038	402.02	10.051	0.50	0.012	0.12%
5,000	497.65	9.953	497.65	9.953	0.00	0.000	0.00%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Residential Service Rates and Proposed 2017 Residential Service Rates

		Rate Code R2	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$17.00	$19.50
Energy Charge - Summer	($/kWh)	$0.11600	$0.11760
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Proposed 2016		Proposed 2017		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	51.38	17.127	54.36	18.120	2.98	0.993	5.80%
400	62.84	15.710	65.98	16.495	3.14	0.785	5.00%
500	74.30	14.860	77.60	15.520	3.30	0.660	4.44%
600	85.76	14.293	89.22	14.870	3.46	0.577	4.03%
700	97.22	13.889	100.84	14.406	3.62	0.517	3.72%
800	108.68	13.585	112.46	14.058	3.78	0.472	3.48%
900	120.14	13.349	124.08	13.787	3.94	0.438	3.28%
1,000	131.60	13.160	135.70	13.570	4.10	0.410	3.12%
1,100	143.06	13.005	147.32	13.393	4.26	0.387	2.98%
1,200	154.52	12.877	158.94	13.245	4.42	0.368	2.86%
1,300	165.98	12.768	170.56	13.120	4.58	0.352	2.76%
1,400	177.44	12.674	182.18	13.013	4.74	0.339	2.67%
1,500	188.90	12.593	193.80	12.920	4.90	0.327	2.59%
2,000	246.20	12.310	251.90	12.595	5.70	0.285	2.32%
2,500	303.50	12.140	310.00	12.400	6.50	0.260	2.14%
3,000	360.80	12.027	368.10	12.270	7.30	0.243	2.02%
4,000	475.40	11.885	484.30	12.108	8.90	0.223	1.87%
5,000	590.00	11.800	600.50	12.010	10.50	0.210	1.78%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Residential Service Rates and Proposed 2017 Residential Service Rates

		Rate Code R2	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$17.00	$19.50
Energy Charge - Non Summer	($/kWh)	$0.09600	$0.09760
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Proposed 2016		Proposed 2017		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	44.58	14.860	47.56	15.853	2.98	0.993	6.68%
400	53.77	13.443	56.91	14.228	3.14	0.785	5.84%
500	62.97	12.593	66.27	13.253	3.30	0.660	5.24%
600	72.16	12.026	75.62	12.603	3.46	0.577	4.80%
700	81.35	11.622	84.97	12.139	3.62	0.517	4.45%
800	90.54	11.318	94.32	11.791	3.78	0.472	4.17%
900	99.74	11.082	103.68	11.520	3.94	0.438	3.95%
1,000	108.93	10.893	113.03	11.303	4.10	0.410	3.76%
1,100	118.12	10.738	122.38	11.126	4.26	0.387	3.61%
1,200	127.32	10.610	131.74	10.978	4.42	0.368	3.47%
1,300	136.51	10.501	141.09	10.853	4.58	0.352	3.36%
1,400	145.70	10.407	150.44	10.746	4.74	0.339	3.25%
1,500	154.90	10.326	159.80	10.653	4.90	0.327	3.16%
2,000	200.86	10.043	206.56	10.328	5.70	0.285	2.84%
2,500	246.83	9.873	253.33	10.133	6.50	0.260	2.63%
3,000	292.79	9.760	300.09	10.003	7.30	0.243	2.49%
4,000	384.72	9.618	393.62	9.841	8.90	0.222	2.31%
5,000	476.65	9.533	487.15	9.743	10.50	0.210	2.20%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Residential Service Rates and Proposed 2017 Residential Service Rates

		Rate Code R4	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$17.00	$19.50
Energy Charge - Summer	($/kWh)	$0.11870	$0.11890
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Proposed 2016		Proposed 2017		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	52.19	17.397	54.75	18.250	2.56	0.853	4.91%
400	63.92	15.980	66.50	16.625	2.58	0.645	4.04%
500	75.65	15.130	78.25	15.650	2.60	0.520	3.44%
600	87.38	14.563	90.00	15.000	2.62	0.437	3.00%
700	99.11	14.159	101.75	14.536	2.64	0.377	2.66%
800	110.84	13.855	113.50	14.188	2.66	0.333	2.40%
900	122.57	13.619	125.25	13.917	2.68	0.298	2.19%
1,000	134.30	13.430	137.00	13.700	2.70	0.270	2.01%
1,100	146.03	13.275	148.75	13.523	2.72	0.247	1.86%
1,200	157.76	13.147	160.50	13.375	2.74	0.228	1.74%
1,300	169.49	13.038	172.25	13.250	2.76	0.212	1.63%
1,400	181.22	12.944	184.00	13.143	2.78	0.199	1.53%
1,500	192.95	12.863	195.75	13.050	2.80	0.187	1.45%
2,000	251.60	12.580	254.50	12.725	2.90	0.145	1.15%
2,500	310.25	12.410	313.25	12.530	3.00	0.120	0.97%
3,000	368.90	12.297	372.00	12.400	3.10	0.103	0.84%
4,000	486.20	12.155	489.50	12.238	3.30	0.083	0.68%
5,000	603.50	12.070	607.00	12.140	3.50	0.070	0.58%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Residential Service Rates and Proposed 2017 Residential Service Rates

		Rate Code R4	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$17.00	$19.50
Energy Charge - Non Summer	($/kWh)	$0.09870	$0.09890
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Proposed 2016		Proposed 2017		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	45.39	15.130	47.95	15.983	2.56	0.853	5.64%
400	54.85	13.713	57.43	14.358	2.58	0.645	4.70%
500	64.32	12.863	66.92	13.383	2.60	0.520	4.04%
600	73.78	12.296	76.40	12.733	2.62	0.437	3.55%
700	83.24	11.892	85.88	12.269	2.64	0.377	3.17%
800	92.70	11.588	95.36	11.921	2.66	0.333	2.87%
900	102.17	11.352	104.85	11.650	2.68	0.298	2.62%
1,000	111.63	11.163	114.33	11.433	2.70	0.270	2.42%
1,100	121.09	11.008	123.81	11.256	2.72	0.247	2.25%
1,200	130.56	10.880	133.30	11.108	2.74	0.228	2.10%
1,300	140.02	10.771	142.78	10.983	2.76	0.212	1.97%
1,400	149.48	10.677	152.26	10.876	2.78	0.199	1.86%
1,500	158.95	10.596	161.75	10.783	2.80	0.187	1.76%
2,000	206.26	10.313	209.16	10.458	2.90	0.145	1.41%
2,500	253.58	10.143	256.58	10.263	3.00	0.120	1.18%
3,000	300.89	10.030	303.99	10.133	3.10	0.103	1.03%
4,000	395.52	9.888	398.82	9.971	3.30	0.082	0.83%
5,000	490.15	9.803	493.65	9.873	3.50	0.070	0.71%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GA	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$21.00	$25.00
Energy Charge - Summer	($/kWh)	$0.11250	$0.11260
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Proposed 2016		Proposed 2017		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	54.33	18.110	58.36	19.453	4.03	1.343	7.42%
400	65.44	16.360	69.48	17.370	4.04	1.010	6.17%
500	76.55	15.310	80.60	16.120	4.05	0.810	5.29%
750	104.33	13.910	108.40	14.453	4.08	0.543	3.91%
1,000	132.10	13.210	136.20	13.620	4.10	0.410	3.10%
2,000	243.20	12.160	247.40	12.370	4.20	0.210	1.73%
3,000	354.30	11.810	358.60	11.953	4.30	0.143	1.21%
4,000	465.40	11.635	469.80	11.745	4.40	0.110	0.95%
5,000	576.50	11.530	581.00	11.620	4.50	0.090	0.78%
6,000	687.60	11.460	692.20	11.537	4.60	0.077	0.67%
7,000	798.70	11.410	803.40	11.477	4.70	0.067	0.59%
8,000	909.80	11.373	914.60	11.433	4.80	0.060	0.53%
9,000	1,020.90	11.343	1,025.80	11.398	4.90	0.054	0.48%
10,000	1,132.00	11.320	1,137.00	11.370	5.00	0.050	0.44%
11,000	1,243.10	11.301	1,248.20	11.347	5.10	0.046	0.41%
12,000	1,354.20	11.285	1,359.40	11.328	5.20	0.043	0.38%
13,000	1,465.30	11.272	1,470.60	11.312	5.30	0.041	0.36%
14,000	1,576.40	11.260	1,581.80	11.299	5.40	0.039	0.34%
15,000	1,687.50	11.250	1,693.00	11.287	5.50	0.037	0.33%
20,000	2,243.00	11.215	2,249.00	11.245	6.00	0.030	0.27%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GA	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$21.00	$25.00
Energy Charge - Non Summer	($/kWh)	$0.09250	$0.09260
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Proposed 2016		Proposed 2017		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	47.53	15.843	51.56	17.186	4.03	1.343	8.48%
400	56.37	14.093	60.41	15.103	4.04	1.010	7.17%
500	65.22	13.043	69.27	13.853	4.05	0.810	6.21%
750	87.32	11.643	91.40	12.186	4.08	0.543	4.67%
1,000	109.43	10.943	113.53	11.353	4.10	0.410	3.75%
2,000	197.86	9.893	202.06	10.103	4.20	0.210	2.12%
3,000	286.29	9.543	290.59	9.686	4.30	0.143	1.50%
4,000	374.72	9.368	379.12	9.478	4.40	0.110	1.17%
5,000	463.15	9.263	467.65	9.353	4.50	0.090	0.97%
6,000	551.58	9.193	556.18	9.270	4.60	0.077	0.83%
7,000	640.01	9.143	644.71	9.210	4.70	0.067	0.73%
8,000	728.44	9.106	733.24	9.166	4.80	0.060	0.66%
9,000	816.87	9.076	821.77	9.131	4.90	0.054	0.60%
10,000	905.30	9.053	910.30	9.103	5.00	0.050	0.55%
11,000	993.73	9.034	998.83	9.080	5.10	0.046	0.51%
12,000	1,082.16	9.018	1,087.36	9.061	5.20	0.043	0.48%
13,000	1,170.59	9.005	1,175.89	9.045	5.30	0.041	0.45%
14,000	1,259.02	8.993	1,264.42	9.032	5.40	0.039	0.43%
15,000	1,347.45	8.983	1,352.95	9.020	5.50	0.037	0.41%
20,000	1,789.60	8.948	1,795.60	8.978	6.00	0.030	0.34%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GB	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$22.94	$23.42
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

Demand	Load	Usage	Proposed 2016		Proposed 2017		Difference		
	Factor		Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,300	1,508.53	20.665	1,533.53	21.007	25.00	0.342	1.66%
	30%	10,950	1,676.80	15.313	1,701.80	15.542	25.00	0.228	1.49%
	40%	14,600	1,845.06	12.637	1,870.06	12.809	25.00	0.171	1.35%
	50%	18,250	2,013.33	11.032	2,038.33	11.169	25.00	0.137	1.24%
	60%	21,900	2,181.59	9.962	2,206.59	10.076	25.00	0.114	1.15%
	70%	25,550	2,349.86	9.197	2,374.86	9.295	25.00	0.098	1.06%
	80%	29,200	2,518.12	8.624	2,543.12	8.709	25.00	0.086	0.99%
100	20%	14,600	2,992.06	20.494	3,041.06	20.829	49.00	0.336	1.64%
	30%	21,900	3,328.59	15.199	3,377.59	15.423	49.00	0.224	1.47%
	40%	29,200	3,665.12	12.552	3,714.12	12.720	49.00	0.168	1.34%
	50%	36,500	4,001.65	10.963	4,050.65	11.098	49.00	0.134	1.22%
	60%	43,800	4,338.18	9.905	4,387.18	10.016	49.00	0.112	1.13%
	70%	51,100	4,674.71	9.148	4,723.71	9.244	49.00	0.096	1.05%
	80%	58,400	5,011.24	8.581	5,060.24	8.665	49.00	0.084	0.98%
200	20%	29,200	5,959.12	20.408	6,056.12	20.740	97.00	0.332	1.63%
	30%	43,800	6,632.18	15.142	6,729.18	15.363	97.00	0.221	1.46%
	40%	58,400	7,305.24	12.509	7,402.24	12.675	97.00	0.166	1.33%
	50%	73,000	7,978.30	10.929	8,075.30	11.062	97.00	0.133	1.22%
	60%	87,600	8,651.36	9.876	8,748.36	9.987	97.00	0.111	1.12%
	70%	102,200	9,324.42	9.124	9,421.42	9.219	97.00	0.095	1.04%
	80%	116,800	9,997.48	8.559	10,094.48	8.643	97.00	0.083	0.97%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GB	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$22.94	$23.42
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	20%	43,800	8,926.18	20.379	9,071.18	20.710	145.00	0.331	1.62%
	30%	65,700	9,935.77	15.123	10,080.77	15.344	145.00	0.221	1.46%
	40%	87,600	10,945.36	12.495	11,090.36	12.660	145.00	0.166	1.32%
	50%	109,500	11,954.95	10.918	12,099.95	11.050	145.00	0.132	1.21%
	60%	131,400	12,964.54	9.866	13,109.54	9.977	145.00	0.110	1.12%
	70%	153,300	13,974.13	9.116	14,119.13	9.210	145.00	0.095	1.04%
	80%	175,200	14,983.72	8.552	15,128.72	8.635	145.00	0.083	0.97%
400	20%	58,400	11,893.24	20.365	12,086.24	20.696	193.00	0.330	1.62%
	30%	87,600	13,239.36	15.113	13,432.36	15.334	193.00	0.220	1.46%
	40%	116,800	14,585.48	12.488	14,778.48	12.653	193.00	0.165	1.32%
	50%	146,000	15,931.60	10.912	16,124.60	11.044	193.00	0.132	1.21%
	60%	175,200	17,277.72	9.862	17,470.72	9.972	193.00	0.110	1.12%
	70%	204,400	18,623.84	9.111	18,816.84	9.206	193.00	0.094	1.04%
	80%	233,600	19,969.96	8.549	20,162.96	8.631	193.00	0.083	0.97%
500	20%	73,000	14,860.30	20.357	15,101.30	20.687	241.00	0.330	1.62%
	30%	109,500	16,542.95	15.108	16,783.95	15.328	241.00	0.220	1.46%
	40%	146,000	18,225.60	12.483	18,466.60	12.648	241.00	0.165	1.32%
	50%	182,500	19,908.25	10.909	20,149.25	11.041	241.00	0.132	1.21%
	60%	219,000	21,590.90	9.859	21,831.90	9.969	241.00	0.110	1.12%
	70%	255,500	23,273.55	9.109	23,514.55	9.203	241.00	0.094	1.04%
	80%	292,000	24,956.20	8.547	25,197.20	8.629	241.00	0.083	0.97%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GB	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$22.94	$23.42
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	1,416.04	19.398	1,441.04	19.740	25.00	0.342	1.77%
	30%	10,950	1,538.06	14.046	1,563.06	14.275	25.00	0.228	1.63%
	40%	14,600	1,660.08	11.370	1,685.08	11.542	25.00	0.171	1.51%
	50%	18,250	1,782.10	9.765	1,807.10	9.902	25.00	0.137	1.40%
	60%	21,900	1,904.12	8.695	1,929.12	8.809	25.00	0.114	1.31%
	70%	25,550	2,026.14	7.930	2,051.14	8.028	25.00	0.098	1.23%
	80%	29,200	2,148.16	7.357	2,173.16	7.442	25.00	0.086	1.16%
100	20%	14,600	2,807.08	19.227	2,856.08	19.562	49.00	0.336	1.75%
	30%	21,900	3,051.12	13.932	3,100.12	14.156	49.00	0.224	1.61%
	40%	29,200	3,295.16	11.285	3,344.16	11.453	49.00	0.168	1.49%
	50%	36,500	3,539.20	9.696	3,588.20	9.831	49.00	0.134	1.38%
	60%	43,800	3,783.23	8.638	3,832.23	8.749	49.00	0.112	1.30%
	70%	51,100	4,027.27	7.881	4,076.27	7.977	49.00	0.096	1.22%
	80%	58,400	4,271.31	7.314	4,320.31	7.398	49.00	0.084	1.15%
200	20%	29,200	5,589.16	19.141	5,686.16	19.473	97.00	0.332	1.74%
	30%	43,800	6,077.23	13.875	6,174.23	14.096	97.00	0.221	1.60%
	40%	58,400	6,565.31	11.242	6,662.31	11.408	97.00	0.166	1.48%
	50%	73,000	7,053.39	9.662	7,150.39	9.795	97.00	0.133	1.38%
	60%	87,600	7,541.47	8.609	7,638.47	8.720	97.00	0.111	1.29%
	70%	102,200	8,029.55	7.857	8,126.55	7.952	97.00	0.095	1.21%
	80%	116,800	8,517.62	7.292	8,614.62	7.376	97.00	0.083	1.14%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GB	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$22.94	$23.42
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Load		Proposed 2016		Proposed 2017		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**43,800**	8,371.23	19.112	8,516.23	19.443	145.00	0.331	1.73%
	30%	**65,700**	9,103.35	13.856	9,248.35	14.077	145.00	0.221	1.59%
	40%	**87,600**	9,835.47	11.228	9,980.47	11.393	145.00	0.166	1.47%
	50%	**109,500**	10,567.59	9.651	10,712.59	9.783	145.00	0.132	1.37%
	60%	**131,400**	11,299.70	8.599	11,444.70	8.710	145.00	0.110	1.28%
	70%	**153,300**	12,031.82	7.849	12,176.82	7.943	145.00	0.095	1.21%
	80%	**175,200**	12,763.94	7.285	12,908.94	7.368	145.00	0.083	1.14%
400	**20%**	**58,400**	11,153.31	19.098	11,346.31	19.429	193.00	0.330	1.73%
	30%	**87,600**	12,129.47	13.846	12,322.47	14.067	193.00	0.220	1.59%
	40%	**116,800**	13,105.62	11.221	13,298.62	11.386	193.00	0.165	1.47%
	50%	**146,000**	14,081.78	9.645	14,274.78	9.777	193.00	0.132	1.37%
	60%	**175,200**	15,057.94	8.595	15,250.94	8.705	193.00	0.110	1.28%
	70%	**204,400**	16,034.09	7.844	16,227.09	7.939	193.00	0.094	1.20%
	80%	**233,600**	17,010.25	7.282	17,203.25	7.364	193.00	0.083	1.13%
500	**20%**	**73,000**	13,935.39	19.090	14,176.39	19.420	241.00	0.330	1.73%
	30%	**109,500**	15,155.59	13.841	15,396.59	14.061	241.00	0.220	1.59%
	40%	**146,000**	16,375.78	11.216	16,616.78	11.381	241.00	0.165	1.47%
	50%	**182,500**	17,595.98	9.642	17,836.98	9.774	241.00	0.132	1.37%
	60%	**219,000**	18,816.17	8.592	19,057.17	8.702	241.00	0.110	1.28%
	70%	**255,500**	20,036.37	7.842	20,277.37	7.936	241.00	0.094	1.20%
	80%	**292,000**	21,256.56	7.280	21,497.56	7.362	241.00	0.083	1.13%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GL	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$23.29	$23.60
Energy Charge - Summer	($/kWh)	$0.04650	$0.04650
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	70%	153,300	13,925.83	9.084	14,019.83	9.145	94.00	0.061	0.68%
	80%	175,200	14,913.52	8.512	15,007.52	8.566	94.00	0.054	0.63%
	90%	197,100	15,901.21	8.068	15,995.21	8.115	94.00	0.048	0.59%
400	70%	204,400	18,559.44	9.080	18,684.44	9.141	125.00	0.061	0.67%
	80%	233,600	19,876.36	8.509	20,001.36	8.562	125.00	0.054	0.63%
	90%	262,800	21,193.28	8.064	21,318.28	8.112	125.00	0.048	0.59%
500	70%	255,500	23,193.05	9.078	23,349.05	9.139	156.00	0.061	0.67%
	80%	292,000	24,839.20	8.507	24,995.20	8.560	156.00	0.053	0.63%
	90%	328,500	26,485.35	8.063	26,641.35	8.110	156.00	0.047	0.59%

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		Rate Code GL	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$23.29	$23.60
Energy Charge - Summer	($/kWh)	$0.04650	$0.04650
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Load		Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
600	**70%**	**306,600**	27,826.66	9.076	28,013.66	9.137	187.00	0.061	0.67%
	80%	**350,400**	29,802.04	8.505	29,989.04	8.559	187.00	0.053	0.63%
	90%	**394,200**	31,777.42	8.061	31,964.42	8.109	187.00	0.047	0.59%
800	**70%**	**408,800**	37,093.88	9.074	37,342.88	9.135	249.00	0.061	0.67%
	80%	**467,200**	39,727.72	8.503	39,976.72	8.557	249.00	0.053	0.63%
	90%	**525,600**	42,361.56	8.060	42,610.56	8.107	249.00	0.047	0.59%
1000	**70%**	**511,000**	46,361.10	9.073	46,672.10	9.133	311.00	0.061	0.67%
	80%	**584,000**	49,653.40	8.502	49,964.40	8.556	311.00	0.053	0.63%
	90%	**657,000**	52,945.70	8.059	53,256.70	8.106	311.00	0.047	0.59%

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		Rate Code GL	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$23.29	$23.60
Energy Charge - Non Summer	($/kWh)	$0.03650	$0.03650
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	70%	153,300	11,983.52	7.817	12,077.52	7.878	94.00	0.061	0.78%
	80%	175,200	12,693.74	7.245	12,787.74	7.299	94.00	0.054	0.74%
	90%	197,100	13,403.95	6.801	13,497.95	6.848	94.00	0.048	0.70%
400	70%	204,400	15,969.69	7.813	16,094.69	7.874	125.00	0.061	0.78%
	80%	233,600	16,916.65	7.242	17,041.65	7.295	125.00	0.054	0.74%
	90%	262,800	17,863.60	6.797	17,988.60	6.845	125.00	0.048	0.70%
500	70%	255,500	19,955.87	7.811	20,111.87	7.872	156.00	0.061	0.78%
	80%	292,000	21,139.56	7.240	21,295.56	7.293	156.00	0.053	0.74%
	90%	328,500	22,323.26	6.796	22,479.26	6.843	156.00	0.047	0.70%

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		Rate Code GL	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$23.29	$23.60
Energy Charge - Non Summer	($/kWh)	$0.03650	$0.03650
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Load		Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
600	70%	306,600	23,942.04	7.809	24,129.04	7.870	187.00	0.061	0.78%
	80%	350,400	25,362.47	7.238	25,549.47	7.292	187.00	0.053	0.74%
	90%	394,200	26,782.91	6.794	26,969.91	6.842	187.00	0.047	0.70%
800	70%	408,800	31,914.38	7.807	32,163.38	7.868	249.00	0.061	0.78%
	80%	467,200	33,808.30	7.236	34,057.30	7.290	249.00	0.053	0.74%
	90%	525,600	35,702.21	6.793	35,951.21	6.840	249.00	0.047	0.70%
1000	70%	511,000	39,886.73	7.806	40,197.73	7.866	311.00	0.061	0.78%
	80%	584,000	42,254.12	7.235	42,565.12	7.289	311.00	0.053	0.74%
	90%	657,000	44,621.51	6.792	44,932.51	6.839	311.00	0.047	0.70%

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		Rate Code GV	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$24.60	$25.04
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

Demand (kW)	Load Factor	Usage (kWh)	Proposed 2016 Amount ($)	Proposed 2016 Unit Cost (Cents/kWh)	Proposed 2017 Amount ($)	Proposed 2017 Unit Cost (Cents/kWh)	Difference Amount ($)	Difference Unit Cost (Cents/kWh)	Difference Percent (%)
50	20%	7,300	1,591.53	21.802	1,614.53	22.117	23.00	0.315	1.45%
	30%	10,950	1,759.80	16.071	1,782.80	16.281	23.00	0.210	1.31%
	40%	14,600	1,928.06	13.206	1,951.06	13.363	23.00	0.158	1.19%
	50%	18,250	2,096.33	11.487	2,119.33	11.613	23.00	0.126	1.10%
	60%	21,900	2,264.59	10.341	2,287.59	10.446	23.00	0.105	1.02%
	70%	25,550	2,432.86	9.522	2,455.86	9.612	23.00	0.090	0.95%
	80%	29,200	2,601.12	8.908	2,624.12	8.987	23.00	0.079	0.88%
100	20%	14,600	3,158.06	21.631	3,203.06	21.939	45.00	0.308	1.42%
	30%	21,900	3,494.59	15.957	3,539.59	16.163	45.00	0.205	1.29%
	40%	29,200	3,831.12	13.120	3,876.12	13.274	45.00	0.154	1.17%
	50%	36,500	4,167.65	11.418	4,212.65	11.542	45.00	0.123	1.08%
	60%	43,800	4,504.18	10.284	4,549.18	10.386	45.00	0.103	1.00%
	70%	51,100	4,840.71	9.473	4,885.71	9.561	45.00	0.088	0.93%
	80%	58,400	5,177.24	8.865	5,222.24	8.942	45.00	0.077	0.87%
200	20%	29,200	6,291.12	21.545	6,380.12	21.850	89.00	0.305	1.41%
	30%	43,800	6,964.18	15.900	7,053.18	16.103	89.00	0.203	1.28%
	40%	58,400	7,637.24	13.077	7,726.24	13.230	89.00	0.152	1.17%
	50%	73,000	8,310.30	11.384	8,399.30	11.506	89.00	0.122	1.07%
	60%	87,600	8,983.36	10.255	9,072.36	10.357	89.00	0.102	0.99%
	70%	102,200	9,656.42	9.449	9,745.42	9.536	89.00	0.087	0.92%
	80%	116,800	10,329.48	8.844	10,418.48	8.920	89.00	0.076	0.86%

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		Rate Code GV	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$24.60	$25.04
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	20%	43,800	9,424.18	21.516	9,557.18	21.820	133.00	0.304	1.41%
	30%	65,700	10,433.77	15.881	10,566.77	16.083	133.00	0.202	1.27%
	40%	87,600	11,443.36	13.063	11,576.36	13.215	133.00	0.152	1.16%
	50%	109,500	12,452.95	11.373	12,585.95	11.494	133.00	0.121	1.07%
	60%	131,400	13,462.54	10.245	13,595.54	10.347	133.00	0.101	0.99%
	70%	153,300	14,472.13	9.440	14,605.13	9.527	133.00	0.087	0.92%
	80%	175,200	15,481.72	8.837	15,614.72	8.913	133.00	0.076	0.86%
400	20%	58,400	12,557.24	21.502	12,734.24	21.805	177.00	0.303	1.41%
	30%	87,600	13,903.36	15.871	14,080.36	16.073	177.00	0.202	1.27%
	40%	116,800	15,249.48	13.056	15,426.48	13.208	177.00	0.152	1.16%
	50%	146,000	16,595.60	11.367	16,772.60	11.488	177.00	0.121	1.07%
	60%	175,200	17,941.72	10.241	18,118.72	10.342	177.00	0.101	0.99%
	70%	204,400	19,287.84	9.436	19,464.84	9.523	177.00	0.087	0.92%
	80%	233,600	20,633.96	8.833	20,810.96	8.909	177.00	0.076	0.86%
500	20%	73,000	15,690.30	21.494	15,911.30	21.796	221.00	0.303	1.41%
	30%	109,500	17,372.95	15.866	17,593.95	16.068	221.00	0.202	1.27%
	40%	146,000	19,055.60	13.052	19,276.60	13.203	221.00	0.151	1.16%
	50%	182,500	20,738.25	11.363	20,959.25	11.485	221.00	0.121	1.07%
	60%	219,000	22,420.90	10.238	22,641.90	10.339	221.00	0.101	0.99%
	70%	255,500	24,103.55	9.434	24,324.55	9.520	221.00	0.086	0.92%
	80%	292,000	25,786.20	8.831	26,007.20	8.907	221.00	0.076	0.86%

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		Rate Code GV	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$24.60	$25.04
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Load		Proposed 2016		Proposed 2017		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,300	1,499.04	20.535	1,522.04	20.850	23.00	0.315	1.53%
	30%	10,950	1,621.06	14.804	1,644.06	15.014	23.00	0.210	1.42%
	40%	14,600	1,743.08	11.939	1,766.08	12.096	23.00	0.158	1.32%
	50%	18,250	1,865.10	10.220	1,888.10	10.346	23.00	0.126	1.23%
	60%	21,900	1,987.12	9.074	2,010.12	9.179	23.00	0.105	1.16%
	70%	25,550	2,109.14	8.255	2,132.14	8.345	23.00	0.090	1.09%
	80%	29,200	2,231.16	7.641	2,254.16	7.720	23.00	0.079	1.03%
100	20%	14,600	2,973.08	20.364	3,018.08	20.672	45.00	0.308	1.51%
	30%	21,900	3,217.12	14.690	3,262.12	14.896	45.00	0.205	1.40%
	40%	29,200	3,461.16	11.853	3,506.16	12.007	45.00	0.154	1.30%
	50%	36,500	3,705.20	10.151	3,750.20	10.275	45.00	0.123	1.21%
	60%	43,800	3,949.23	9.017	3,994.23	9.119	45.00	0.103	1.14%
	70%	51,100	4,193.27	8.206	4,238.27	8.294	45.00	0.088	1.07%
	80%	58,400	4,437.31	7.598	4,482.31	7.675	45.00	0.077	1.01%
200	20%	29,200	5,921.16	20.278	6,010.16	20.583	89.00	0.305	1.50%
	30%	43,800	6,409.23	14.633	6,498.23	14.836	89.00	0.203	1.39%
	40%	58,400	6,897.31	11.810	6,986.31	11.963	89.00	0.152	1.29%
	50%	73,000	7,385.39	10.117	7,474.39	10.239	89.00	0.122	1.21%
	60%	87,600	7,873.47	8.988	7,962.47	9.090	89.00	0.102	1.13%
	70%	102,200	8,361.55	8.182	8,450.55	8.269	89.00	0.087	1.06%
	80%	116,800	8,849.62	7.577	8,938.62	7.653	89.00	0.076	1.01%

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		Rate Code GV	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$24.60	$25.04
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Load		Proposed 2016		Proposed 2017		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**43,800**	8,869.23	20.249	9,002.23	20.553	133.00	0.304	1.50%
	30%	**65,700**	9,601.35	14.614	9,734.35	14.816	133.00	0.202	1.39%
	40%	**87,600**	10,333.47	11.796	10,466.47	11.948	133.00	0.152	1.29%
	50%	**109,500**	11,065.59	10.106	11,198.59	10.227	133.00	0.121	1.20%
	60%	**131,400**	11,797.70	8.978	11,930.70	9.080	133.00	0.101	1.13%
	70%	**153,300**	12,529.82	8.173	12,662.82	8.260	133.00	0.087	1.06%
	80%	**175,200**	13,261.94	7.570	13,394.94	7.646	133.00	0.076	1.00%
400	**20%**	**58,400**	11,817.31	20.235	11,994.31	20.538	177.00	0.303	1.50%
	30%	**87,600**	12,793.47	14.604	12,970.47	14.806	177.00	0.202	1.38%
	40%	**116,800**	13,769.62	11.789	13,946.62	11.941	177.00	0.152	1.29%
	50%	**146,000**	14,745.78	10.100	14,922.78	10.221	177.00	0.121	1.20%
	60%	**175,200**	15,721.94	8.974	15,898.94	9.075	177.00	0.101	1.13%
	70%	**204,400**	16,698.09	8.169	16,875.09	8.256	177.00	0.087	1.06%
	80%	**233,600**	17,674.25	7.566	17,851.25	7.642	177.00	0.076	1.00%
500	**20%**	**73,000**	14,765.39	20.227	14,986.39	20.529	221.00	0.303	1.50%
	30%	**109,500**	15,985.59	14.599	16,206.59	14.801	221.00	0.202	1.38%
	40%	**146,000**	17,205.78	11.785	17,426.78	11.936	221.00	0.151	1.28%
	50%	**182,500**	18,425.98	10.096	18,646.98	10.218	221.00	0.121	1.20%
	60%	**219,000**	19,646.17	8.971	19,867.17	9.072	221.00	0.101	1.12%
	70%	**255,500**	20,866.37	8.167	21,087.37	8.253	221.00	0.086	1.06%
	80%	**292,000**	22,086.56	7.564	22,307.56	7.640	221.00	0.076	1.00%

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Rate Code GT		Proposed 2016	Proposed 2017
Customer Charge	($)	$30.00000	$31.00000
Demand Charge - On-Peak	($/kW)	$25.23000	$25.76000
Demand Charge - Off-Peak	($/kW)	$13.28000	$13.94000
Energy Charge - Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,390	1,074.90	14.545	1,107.90	14.992	33.00	0.446	3.07%
	30%	11,085	1,219.18	10.998	1,252.17	11.296	33.00	0.298	2.71%
	40%	14,780	1,363.45	9.225	1,396.45	9.448	33.00	0.223	2.42%
	50%	18,475	1,507.73	8.161	1,540.72	8.339	33.00	0.179	2.19%
	60%	22,170	1,652.00	7.452	1,685.00	7.600	33.00	0.149	2.00%
	70%	25,865	1,796.28	6.945	1,829.27	7.072	33.00	0.128	1.84%
	80%	29,560	1,940.55	6.565	1,973.55	6.676	33.00	0.112	1.70%
100	20%	14,780	2,119.80	14.342	2,184.79	14.782	64.99	0.440	3.07%
	30%	22,170	2,408.35	10.863	2,473.34	11.156	64.99	0.293	2.70%
	40%	29,560	2,696.90	9.123	2,761.89	9.343	64.99	0.220	2.41%
	50%	36,950	2,985.45	8.080	3,050.44	8.256	64.99	0.176	2.18%
	60%	44,340	3,274.00	7.384	3,338.99	7.530	64.99	0.147	1.99%
	70%	51,730	3,562.55	6.887	3,627.54	7.012	64.99	0.126	1.82%
	80%	59,120	3,851.10	6.514	3,916.09	6.624	64.99	0.110	1.69%
200	20%	29,560	4,209.60	14.241	4,338.58	14.677	128.98	0.436	3.06%
	30%	44,340	4,786.70	10.795	4,915.68	11.086	128.98	0.291	2.69%
	40%	59,120	5,363.80	9.073	5,492.78	9.291	128.98	0.218	2.40%
	50%	73,900	5,940.90	8.039	6,069.88	8.214	128.98	0.175	2.17%
	60%	88,680	6,518.00	7.350	6,646.98	7.495	128.98	0.145	1.98%
	70%	103,460	7,095.10	6.858	7,224.08	6.982	128.98	0.125	1.82%
	80%	118,240	7,672.20	6.489	7,801.18	6.598	128.98	0.109	1.68%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GT	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$30.00000	$31.00000
Demand Charge - On-Peak	($/kW)	$25.23000	$25.76000
Demand Charge - Off-Peak	($/kW)	$13.28000	$13.94000
Energy Charge - Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Load		Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	20%	44,340	6,299.40	14.207	6,492.37	14.642	192.97	0.435	3.06%
	30%	66,510	7,165.05	10.773	7,358.02	11.063	192.97	0.290	2.69%
	40%	88,680	8,030.70	9.056	8,223.67	9.273	192.97	0.218	2.40%
	50%	110,850	8,896.35	8.026	9,089.32	8.200	192.97	0.174	2.17%
	60%	133,020	9,762.00	7.339	9,954.97	7.484	192.97	0.145	1.98%
	70%	155,190	10,627.65	6.848	10,820.62	6.972	192.97	0.124	1.82%
	80%	177,360	11,493.30	6.480	11,686.27	6.589	192.97	0.109	1.68%
400	20%	59,120	8,389.20	14.190	8,646.17	14.625	256.96	0.435	3.06%
	30%	88,680	9,543.40	10.762	9,800.37	11.051	256.96	0.290	2.69%
	40%	118,240	10,697.60	9.047	10,954.56	9.265	256.96	0.217	2.40%
	50%	147,800	11,851.80	8.019	12,108.76	8.193	256.96	0.174	2.17%
	60%	177,360	13,006.00	7.333	13,262.96	7.478	256.96	0.145	1.98%
	70%	206,920	14,160.20	6.843	14,417.16	6.968	256.96	0.124	1.81%
	80%	236,480	15,314.40	6.476	15,571.36	6.585	256.96	0.109	1.68%
500	20%	73,900	10,479.00	14.180	10,799.96	14.614	320.95	0.434	3.06%
	30%	110,850	11,921.75	10.755	12,242.71	11.044	320.95	0.290	2.69%
	40%	147,800	13,364.50	9.042	13,685.46	9.259	320.95	0.217	2.40%
	50%	184,750	14,807.25	8.015	15,128.21	8.188	320.95	0.174	2.17%
	60%	221,700	16,250.00	7.330	16,570.95	7.474	320.95	0.145	1.98%
	70%	258,650	17,692.75	6.840	18,013.70	6.965	320.95	0.124	1.81%
	80%	295,600	19,135.50	6.473	19,456.45	6.582	320.95	0.109	1.68%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GT	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$30.00	$31.00
Demand Charge - On-Peak	($/kW)	$25.23	$25.76
Demand Charge - Off-Peak	($/kW)	$13.28	$13.94
Energy Charge - Nonsummer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Nonsummer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

			Proposed 2016		Proposed 2017		Difference		
Demand	Load Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,390	1,029.36	13.929	1,062.59	14.379	33.23	0.450	3.23%
	30%	11,085	1,161.64	10.479	1,194.87	10.779	33.23	0.300	2.86%
	40%	14,780	1,293.92	8.755	1,327.15	8.979	33.23	0.225	2.57%
	50%	18,475	1,426.20	7.720	1,459.43	7.899	33.23	0.180	2.33%
	60%	22,170	1,558.48	7.030	1,591.71	7.180	33.23	0.150	2.13%
	70%	25,865	1,690.76	6.537	1,723.99	6.665	33.23	0.128	1.97%
	80%	29,560	1,823.04	6.167	1,856.27	6.280	33.23	0.112	1.82%
100	20%	14,780	2,028.72	13.726	2,094.18	14.169	65.46	0.443	3.23%
	30%	22,170	2,293.28	10.344	2,358.74	10.639	65.46	0.295	2.85%
	40%	29,560	2,557.84	8.653	2,623.30	8.875	65.46	0.221	2.56%
	50%	36,950	2,822.40	7.638	2,887.86	7.816	65.46	0.177	2.32%
	60%	44,340	3,086.97	6.962	3,152.42	7.110	65.46	0.148	2.12%
	70%	51,730	3,351.53	6.479	3,416.99	6.605	65.46	0.127	1.95%
	80%	59,120	3,616.09	6.117	3,681.55	6.227	65.46	0.111	1.81%
200	20%	29,560	4,027.44	13.625	4,157.36	14.064	129.92	0.440	3.23%
	30%	44,340	4,556.56	10.276	4,686.48	10.569	129.92	0.293	2.85%
	40%	59,120	5,085.69	8.602	5,215.61	8.822	129.92	0.220	2.55%
	50%	73,900	5,614.81	7.598	5,744.73	7.774	129.92	0.176	2.31%
	60%	88,680	6,143.93	6.928	6,273.85	7.075	129.92	0.147	2.11%
	70%	103,460	6,673.05	6.450	6,802.97	6.575	129.92	0.126	1.95%
	80%	118,240	7,202.17	6.091	7,332.09	6.201	129.92	0.110	1.80%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2016 General Service Rates and Proposed 2017 General Service Rates

		Rate Code GT	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$30.00	$31.00
Demand Charge - On-Peak	($/kW)	$25.23	$25.76
Demand Charge - Off-Peak	($/kW)	$13.28	$13.94
Energy Charge - Nonsummer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Nonsummer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Load		Proposed 2016		Proposed 2017		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**44,340**	6,026.16	13.591	6,220.54	14.029	194.38	0.438	3.23%
	30%	**66,510**	6,819.85	10.254	7,014.23	10.546	194.38	0.292	2.85%
	40%	**88,680**	7,613.53	8.585	7,807.91	8.805	194.38	0.219	2.55%
	50%	**110,850**	8,407.21	7.584	8,601.59	7.760	194.38	0.175	2.31%
	60%	**133,020**	9,200.90	6.917	9,395.27	7.063	194.38	0.146	2.11%
	70%	**155,190**	9,994.58	6.440	10,188.96	6.565	194.38	0.125	1.94%
	80%	**177,360**	10,788.26	6.083	10,982.64	6.192	194.38	0.110	1.80%
400	**20%**	**59,120**	8,024.89	13.574	8,283.72	14.012	258.84	0.438	3.23%
	30%	**88,680**	9,083.13	10.243	9,341.97	10.534	258.84	0.292	2.85%
	40%	**118,240**	10,141.37	8.577	10,400.21	8.796	258.84	0.219	2.55%
	50%	**147,800**	11,199.62	7.578	11,458.46	7.753	258.84	0.175	2.31%
	60%	**177,360**	12,257.86	6.911	12,516.70	7.057	258.84	0.146	2.11%
	70%	**206,920**	13,316.10	6.435	13,574.94	6.560	258.84	0.125	1.94%
	80%	**236,480**	14,374.35	6.078	14,633.19	6.188	258.84	0.109	1.80%
500	**20%**	**73,900**	10,023.61	13.564	10,346.90	14.001	323.30	0.437	3.23%
	30%	**110,850**	11,346.41	10.236	11,669.71	10.527	323.30	0.292	2.85%
	40%	**147,800**	12,669.22	8.572	12,992.51	8.791	323.30	0.219	2.55%
	50%	**184,750**	13,992.02	7.573	14,315.32	7.748	323.30	0.175	2.31%
	60%	**221,700**	15,314.83	6.908	15,638.12	7.054	323.30	0.146	2.11%
	70%	**258,650**	16,637.63	6.432	16,960.93	6.557	323.30	0.125	1.94%
	80%	**295,600**	17,960.44	6.076	18,283.73	6.185	323.30	0.109	1.80%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2016 Temporary Service Rates and Proposed 2017 Temporary Service Rates

		Rate Code TP	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$21.00	$22.00
Energy Charge - Summer	($/kWh)	$0.14060	$0.14120
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Proposed 2016		Proposed 2017		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	62.76	20.920	63.94	21.313	1.18	0.393	1.88%
400	76.68	19.170	77.92	19.480	1.24	0.310	1.62%
500	90.60	18.120	91.90	18.380	1.30	0.260	1.43%
750	125.40	16.720	126.85	16.913	1.45	0.193	1.16%
1,000	160.20	16.020	161.80	16.180	1.60	0.160	1.00%
2,000	299.40	14.970	301.60	15.080	2.20	0.110	0.73%
3,000	438.60	14.620	441.40	14.713	2.80	0.093	0.64%
4,000	577.80	14.445	581.20	14.530	3.40	0.085	0.59%
5,000	717.00	14.340	721.00	14.420	4.00	0.080	0.56%
6,000	856.20	14.270	860.80	14.347	4.60	0.077	0.54%
7,000	995.40	14.220	1,000.60	14.294	5.20	0.074	0.52%
8,000	1,134.60	14.183	1,140.40	14.255	5.80	0.073	0.51%
9,000	1,273.80	14.153	1,280.20	14.224	6.40	0.071	0.50%
10,000	1,413.00	14.130	1,420.00	14.200	7.00	0.070	0.50%
11,000	1,552.20	14.111	1,559.80	14.180	7.60	0.069	0.49%
12,000	1,691.40	14.095	1,699.60	14.163	8.20	0.068	0.48%
13,000	1,830.60	14.082	1,839.40	14.149	8.80	0.068	0.48%
14,000	1,969.80	14.070	1,979.20	14.137	9.40	0.067	0.48%
15,000	2,109.00	14.060	2,119.00	14.127	10.00	0.067	0.47%
20,000	2,805.00	14.025	2,818.00	14.090	13.00	0.065	0.46%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2016 Temporary Service Rates and Proposed 2017 Temporary Service Rates

		Rate Code TP	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$21.00	$22.00
Energy Charge - Non Summer	($/kWh)	$0.12060	$0.12120
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

	Proposed 2016		Proposed 2017		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	55.96	18.653	57.14	19.046	1.18	0.393	2.11%
400	67.61	16.903	68.85	17.213	1.24	0.310	1.83%
500	79.27	15.853	80.57	16.113	1.30	0.260	1.64%
750	108.40	14.453	109.85	14.646	1.45	0.193	1.34%
1,000	137.53	13.753	139.13	13.913	1.60	0.160	1.16%
2,000	254.06	12.703	256.26	12.813	2.20	0.110	0.87%
3,000	370.59	12.353	373.39	12.446	2.80	0.093	0.76%
4,000	487.12	12.178	490.52	12.263	3.40	0.085	0.70%
5,000	603.65	12.073	607.65	12.153	4.00	0.080	0.66%
6,000	720.18	12.003	724.78	12.080	4.60	0.077	0.64%
7,000	836.71	11.953	841.91	12.027	5.20	0.074	0.62%
8,000	953.24	11.916	959.04	11.988	5.80	0.072	0.61%
9,000	1,069.77	11.886	1,076.17	11.957	6.40	0.071	0.60%
10,000	1,186.30	11.863	1,193.30	11.933	7.00	0.070	0.59%
11,000	1,302.83	11.844	1,310.43	11.913	7.60	0.069	0.58%
12,000	1,419.36	11.828	1,427.56	11.896	8.20	0.068	0.58%
13,000	1,535.89	11.815	1,544.69	11.882	8.80	0.068	0.57%
14,000	1,652.42	11.803	1,661.82	11.870	9.40	0.067	0.57%
15,000	1,768.95	11.793	1,778.95	11.860	10.00	0.067	0.57%
20,000	2,351.60	11.758	2,364.60	11.823	13.00	0.065	0.55%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2016 Transition Adjustment and Proposed 2017 Transition Adjustment

		Rate Code TA	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$9.75	$12.65
Energy Charge - Summer	($/kWh)	$0.07563	$0.07000
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

Demand	Load Factor	Usage	Proposed 2016 Amount	Proposed 2016 Unit Cost	Proposed 2017 Amount	Proposed 2017 Unit Cost	Difference Amount	Difference Unit Cost	Difference Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	**20%**	**7,300**	1,054.32	14.443	1,159.01	15.877	104.69	1.434	9.93%
	30%	**10,950**	1,325.13	12.102	1,409.40	12.871	84.27	0.770	6.36%
	40%	**14,600**	1,596.05	10.932	1,659.79	11.368	63.74	0.437	3.99%
	50%	**18,250**	1,866.97	10.230	1,910.18	10.467	43.21	0.237	2.31%
	60%	**21,900**	2,137.89	9.762	2,160.57	9.866	22.68	0.104	1.06%
	70%	**25,550**	2,408.81	9.428	2,410.96	9.436	2.15	0.008	0.09%
	80%	**29,200**	2,679.73	9.177	2,661.35	9.114	(18.38)	(0.063)	-0.69%
100	**20%**	**14,600**	2,083.41	14.270	2,292.02	15.699	208.61	1.429	10.01%
	30%	**21,900**	2,625.25	11.987	2,792.80	12.752	167.54	0.765	6.38%
	40%	**29,200**	3,167.10	10.846	3,293.58	11.279	126.48	0.433	3.99%
	50%	**36,500**	3,708.94	10.161	3,794.36	10.395	85.42	0.234	2.30%
	60%	**43,800**	4,250.78	9.705	4,295.14	9.806	44.35	0.101	1.04%
	70%	**51,100**	4,792.62	9.379	4,795.92	9.385	3.29	0.006	0.07%
	80%	**58,400**	5,334.47	9.134	5,296.70	9.070	(37.77)	(0.065)	-0.71%
200	**20%**	**29,200**	4,141.82	14.184	4,558.03	15.610	416.21	1.425	10.05%
	30%	**43,800**	5,225.51	11.930	5,559.59	12.693	334.09	0.763	6.39%
	40%	**58,400**	6,309.19	10.803	6,561.15	11.235	251.96	0.431	3.99%
	50%	**73,000**	7,392.88	10.127	7,562.71	10.360	169.83	0.233	2.30%
	60%	**87,600**	8,476.56	9.676	8,564.27	9.777	87.71	0.100	1.03%
	70%	**102,200**	9,560.25	9.354	9,565.83	9.360	5.58	0.005	0.06%
	80%	**116,800**	10,643.93	9.113	10,567.39	9.047	(76.54)	(0.066)	-0.72%

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Comparison of Proposed 2016 Transition Adjustment and Proposed 2017 Transition Adjustment

		Rate Code TA	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$9.75	$12.65
Energy Charge - Summer	($/kWh)	$0.07563	$0.07000
Demand Sales Adjustment	($/kWh)	-$0.00223	-$0.00223
Fuel Adjustment	($/kWh)	$0.00083	$0.00083

	Load		Proposed 2016		Proposed 2017		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**43,800**	6,200.24	14.156	6,824.05	15.580	623.82	1.424	10.06%
	30%	**65,700**	7,825.76	11.911	8,326.39	12.673	500.63	0.762	6.40%
	40%	**87,600**	9,451.29	10.789	9,828.73	11.220	377.44	0.431	3.99%
	50%	**109,500**	11,076.82	10.116	11,331.07	10.348	254.25	0.232	2.30%
	60%	**131,400**	12,702.35	9.667	12,833.41	9.767	131.07	0.100	1.03%
	70%	**153,300**	14,327.87	9.346	14,335.75	9.351	7.88	0.005	0.05%
	80%	**175,200**	15,953.40	9.106	15,838.09	9.040	(115.31)	(0.066)	-0.72%
400	**20%**	**58,400**	8,258.65	14.142	9,090.07	15.565	831.42	1.424	10.07%
	30%	**87,600**	10,426.02	11.902	11,093.19	12.663	667.17	0.762	6.40%
	40%	**116,800**	12,593.39	10.782	13,096.31	11.213	502.92	0.431	3.99%
	50%	**146,000**	14,760.76	10.110	15,099.43	10.342	338.67	0.232	2.29%
	60%	**175,200**	16,928.13	9.662	17,102.55	9.762	174.42	0.100	1.03%
	70%	**204,400**	19,095.50	9.342	19,105.67	9.347	10.17	0.005	0.05%
	80%	**233,600**	21,262.87	9.102	21,108.79	9.036	(154.08)	(0.066)	-0.72%
500	**20%**	**73,000**	10,317.06	14.133	11,356.09	15.556	1,039.03	1.423	10.07%
	30%	**109,500**	13,026.27	11.896	13,859.99	12.658	833.71	0.761	6.40%
	40%	**146,000**	15,735.49	10.778	16,363.89	11.208	628.40	0.430	3.99%
	50%	**182,500**	18,444.70	10.107	18,867.79	10.339	423.09	0.232	2.29%
	60%	**219,000**	21,153.91	9.659	21,371.69	9.759	217.78	0.099	1.03%
	70%	**255,500**	23,863.12	9.340	23,875.59	9.345	12.46	0.005	0.05%
	80%	**292,000**	26,572.34	9.100	26,379.49	9.034	(192.85)	(0.066)	-0.73%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Transition Adjustment and Proposed 2017 Transition Adjustment

		Rate Code TA	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$9.75	$12.65
Energy Charge - Nonsummer	($/kWh)	$0.06563	$0.06000
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	961.68	13.174	1,066.63	14.611	104.95	1.438	10.91%
	30%	10,950	1,186.35	10.834	1,270.77	11.605	84.42	0.771	7.12%
	40%	14,600	1,411.03	9.665	1,474.92	10.102	63.89	0.438	4.53%
	50%	18,250	1,635.71	8.963	1,679.06	9.200	43.36	0.238	2.65%
	60%	21,900	1,860.38	8.495	1,883.21	8.599	22.83	0.104	1.23%
	70%	25,550	2,085.06	8.161	2,087.35	8.170	2.29	0.009	0.11%
	80%	29,200	2,309.73	7.910	2,291.50	7.848	(18.24)	(0.062)	-0.79%
100	20%	14,600	1,898.36	13.002	2,107.26	14.433	208.90	1.431	11.00%
	30%	21,900	2,347.71	10.720	2,515.55	11.487	167.84	0.766	7.15%
	40%	29,200	2,797.06	9.579	2,923.84	10.013	126.78	0.434	4.53%
	50%	36,500	3,246.41	8.894	3,332.13	9.129	85.71	0.235	2.64%
	60%	43,800	3,695.76	8.438	3,740.41	8.540	44.65	0.102	1.21%
	70%	51,100	4,145.11	8.112	4,148.70	8.119	3.59	0.007	0.09%
	80%	58,400	4,594.47	7.867	4,556.99	7.803	(37.47)	(0.064)	-0.82%
200	20%	29,200	3,771.71	12.917	4,188.52	14.344	416.80	1.427	11.05%
	30%	43,800	4,670.42	10.663	5,005.09	11.427	334.68	0.764	7.17%
	40%	58,400	5,569.12	9.536	5,821.67	9.969	252.55	0.432	4.53%
	50%	73,000	6,467.82	8.860	6,638.25	9.093	170.43	0.233	2.64%
	60%	87,600	7,366.52	8.409	7,454.83	8.510	88.30	0.101	1.20%
	70%	102,200	8,265.23	8.087	8,271.41	8.093	6.18	0.006	0.07%
	80%	116,800	9,163.93	7.846	9,087.98	7.781	(75.95)	(0.065)	-0.83%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Transition Adjustment and Proposed 2017 Transition Adjustment

		Rate Code TA	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$25.00	$26.00
Demand Charge	($/kW)	$9.75	$12.65
Energy Charge - Nonsummer	($/kWh)	$0.06563	$0.06000
Demand Sales Adjustment	($/kWh)	-$0.00297	-$0.00297
Fuel Adjustment	($/kWh)	-$0.00110	-$0.00110

Demand	Load Factor	Usage	Proposed 2016 Amount	Proposed 2016 Unit Cost	Proposed 2017 Amount	Proposed 2017 Unit Cost	Difference Amount	Difference Unit Cost	Difference Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**43,800**	5,645.07	12.888	6,269.77	14.315	624.71	1.426	11.07%
	30%	**65,700**	6,993.12	10.644	7,494.64	11.407	501.52	0.763	7.17%
	40%	**87,600**	8,341.18	9.522	8,719.51	9.954	378.33	0.432	4.54%
	50%	**109,500**	9,689.23	8.849	9,944.38	9.082	255.14	0.233	2.63%
	60%	**131,400**	11,037.29	8.400	11,169.24	8.500	131.96	0.100	1.20%
	70%	**153,300**	12,385.34	8.079	12,394.11	8.085	8.77	0.006	0.07%
	80%	**175,200**	13,733.40	7.839	13,618.98	7.773	(114.42)	(0.065)	-0.83%
400	**20%**	**58,400**	7,518.42	12.874	8,351.03	14.300	832.61	1.426	11.07%
	30%	**87,600**	9,315.83	10.635	9,984.19	11.397	668.36	0.763	7.17%
	40%	**116,800**	11,113.24	9.515	11,617.34	9.946	504.11	0.432	4.54%
	50%	**146,000**	12,910.64	8.843	13,250.50	9.076	339.86	0.233	2.63%
	60%	**175,200**	14,708.05	8.395	14,883.66	8.495	175.61	0.100	1.19%
	70%	**204,400**	16,505.45	8.075	16,516.81	8.081	11.36	0.006	0.07%
	80%	**233,600**	18,302.86	7.835	18,149.97	7.770	(152.89)	(0.065)	-0.84%
500	**20%**	**73,000**	9,391.78	12.865	10,432.29	14.291	1,040.51	1.425	11.08%
	30%	**109,500**	11,638.54	10.629	12,473.74	11.392	835.20	0.763	7.18%
	40%	**146,000**	13,885.30	9.510	14,515.18	9.942	629.88	0.431	4.54%
	50%	**182,500**	16,132.05	8.839	16,556.63	9.072	424.57	0.233	2.63%
	60%	**219,000**	18,378.81	8.392	18,598.07	8.492	219.26	0.100	1.19%
	70%	**255,500**	20,625.57	8.073	20,639.52	8.078	13.95	0.005	0.07%
	80%	**292,000**	22,872.33	7.833	22,680.96	7.767	(191.37)	(0.066)	-0.84%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Industrial Service Rate and Proposed 2017 Industrial Service Rate

		Rate Code L	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$3,400.00	$3,400.00
Base Demand First 300 kW	($)	$7,332.00	$7,511.40
Additional Demand Charge	($/kW)	$18.80	$19.26
Energy Charge - On-Peak	($/kWh)	$0.05750	$0.05750
Energy Charge - Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kW)	-$0.99669	-$0.99669
Fuel Adjustment	($/kWh)	$0.00080	$0.00080

			Proposed 2016		Proposed 2017		Difference		
Demand	Load Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
1,000	**20%**	**146,000**	28,990.52	19.857	29,491.92	20.200	501.40	0.343	1.73%
	30%	**219,000**	31,888.62	14.561	32,390.02	14.790	501.40	0.229	1.57%
	40%	**292,000**	34,786.72	11.913	35,288.12	12.085	501.40	0.172	1.44%
	50%	**365,000**	37,684.82	10.325	38,186.22	10.462	501.40	0.137	1.33%
	60%	**438,000**	40,582.92	9.266	41,084.32	9.380	501.40	0.114	1.24%
	70%	**511,000**	43,481.02	8.509	43,982.42	8.607	501.40	0.098	1.15%
	80%	**584,000**	46,379.12	7.942	46,880.52	8.027	501.40	0.086	1.08%
1,500	**20%**	**219,000**	40,790.27	18.626	41,521.67	18.960	731.40	0.334	1.79%
	30%	**328,500**	45,137.42	13.740	45,868.82	13.963	731.40	0.223	1.62%
	40%	**438,000**	49,484.57	11.298	50,215.97	11.465	731.40	0.167	1.48%
	50%	**547,500**	53,831.72	9.832	54,563.12	9.966	731.40	0.134	1.36%
	60%	**657,000**	58,178.87	8.855	58,910.27	8.967	731.40	0.111	1.26%
	70%	**766,500**	62,526.02	8.157	63,257.42	8.253	731.40	0.095	1.17%
	80%	**876,000**	66,873.17	7.634	67,604.57	7.717	731.40	0.083	1.09%
2,000	**20%**	**292,000**	52,590.03	18.010	53,551.43	18.340	961.40	0.329	1.83%
	30%	**438,000**	58,386.23	13.330	59,347.63	13.550	961.40	0.219	1.65%
	40%	**584,000**	64,182.43	10.990	65,143.83	11.155	961.40	0.165	1.50%
	50%	**730,000**	69,978.63	9.586	70,940.03	9.718	961.40	0.132	1.37%
	60%	**876,000**	75,774.83	8.650	76,736.23	8.760	961.40	0.110	1.27%
	70%	**1,022,000**	81,571.03	7.982	82,532.43	8.076	961.40	0.094	1.18%
	80%	**1,168,000**	87,367.23	7.480	88,328.63	7.562	961.40	0.082	1.10%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Industrial Service Rate and Proposed 2017 Industrial Service Rate

		Rate Code L	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$3,400.00	$3,400.00
Base Demand First 300 kW	($)	$7,332.00	$7,511.40
Additional Demand Charge	($/kW)	$18.80	$19.26
Energy Charge - On-Peak	($/kWh)	$0.05750	$0.05750
Energy Charge - Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kW)	-$0.99669	-$0.99669
Fuel Adjustment	($/kWh)	$0.00080	$0.00080

	Load		Proposed 2016		Proposed 2017		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
3,000	20%	438,000	76,189.54	17.395	77,610.94	17.719	1,421.40	0.325	1.87%
	30%	657,000	84,883.84	12.920	86,305.24	13.136	1,421.40	0.216	1.67%
	40%	876,000	93,578.14	10.682	94,999.54	10.845	1,421.40	0.162	1.52%
	50%	1,095,000	102,272.44	9.340	103,693.84	9.470	1,421.40	0.130	1.39%
	60%	1,314,000	110,966.74	8.445	112,388.14	8.553	1,421.40	0.108	1.28%
	70%	1,533,000	119,661.04	7.806	121,082.44	7.898	1,421.40	0.093	1.19%
	80%	1,752,000	128,355.34	7.326	129,776.74	7.407	1,421.40	0.081	1.11%
4,000	20%	584,000	99,789.05	17.087	101,670.45	17.409	1,881.40	0.322	1.89%
	30%	876,000	111,381.45	12.715	113,262.85	12.930	1,881.40	0.215	1.69%
	40%	1,168,000	122,973.85	10.529	124,855.25	10.690	1,881.40	0.161	1.53%
	50%	1,460,000	134,566.25	9.217	136,447.65	9.346	1,881.40	0.129	1.40%
	60%	1,752,000	146,158.65	8.342	148,040.05	8.450	1,881.40	0.107	1.29%
	70%	2,044,000	157,751.05	7.718	159,632.45	7.810	1,881.40	0.092	1.19%
	80%	2,336,000	169,343.45	7.249	171,224.85	7.330	1,881.40	0.081	1.11%
5,000	20%	730,000	123,388.56	16.903	125,729.96	17.223	2,341.40	0.321	1.90%
	30%	1,095,000	137,879.06	12.592	140,220.46	12.806	2,341.40	0.214	1.70%
	40%	1,460,000	152,369.56	10.436	154,710.96	10.597	2,341.40	0.160	1.54%
	50%	1,825,000	166,860.06	9.143	169,201.46	9.271	2,341.40	0.128	1.40%
	60%	2,190,000	181,350.56	8.281	183,691.96	8.388	2,341.40	0.107	1.29%
	70%	2,555,000	195,841.06	7.665	198,182.46	7.757	2,341.40	0.092	1.20%
	80%	2,920,000	210,331.56	7.203	212,672.96	7.283	2,341.40	0.080	1.11%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Municipal Service Rate and Proposed 2017 Municipal Service Rate

		Rate Code ML	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$1,400.00	$1,500.00
Base Demand First 1,000 kW	($)	$17,240.00	$17,380.00
Additional Demand Charge	($/kW)	$17.24	$17.38
Energy Charge	($/kWh)	$0.04100	$0.04160
Demand Sales Adjustment	($/kW)	-$0.99669	-$0.99669
Fuel Adjustment	($/kWh)	$0.00080	$0.00080

			Proposed 2016		Proposed 2017		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
5,000	**20%**	**730,000**	113,130.55	15.497	114,368.55	15.667	1,238.00	0.170	1.09%
	30%	**1,095,000**	128,387.55	11.725	129,844.55	11.858	1,457.00	0.133	1.13%
	40%	**1,460,000**	143,644.55	9.839	145,320.55	9.953	1,676.00	0.115	1.17%
	50%	**1,825,000**	158,901.55	8.707	160,796.55	8.811	1,895.00	0.104	1.19%
	60%	**2,190,000**	174,158.55	7.952	176,272.55	8.049	2,114.00	0.097	1.21%
10,000	**20%**	**1,460,000**	224,861.10	15.401	227,237.10	15.564	2,376.00	0.163	1.06%
	30%	**2,190,000**	255,375.10	11.661	258,189.10	11.789	2,814.00	0.128	1.10%
	40%	**2,920,000**	285,889.10	9.791	289,141.10	9.902	3,252.00	0.111	1.14%
	50%	**3,650,000**	316,403.10	8.669	320,093.10	8.770	3,690.00	0.101	1.17%
	60%	**4,380,000**	346,917.10	7.920	351,045.10	8.015	4,128.00	0.094	1.19%
15,000	**20%**	**2,190,000**	336,591.65	15.369	340,105.65	15.530	3,514.00	0.160	1.04%
	30%	**3,285,000**	382,362.65	11.640	386,533.65	11.767	4,171.00	0.127	1.09%
	40%	**4,380,000**	428,133.65	9.775	432,961.65	9.885	4,828.00	0.110	1.13%
	50%	**5,475,000**	473,904.65	8.656	479,389.65	8.756	5,485.00	0.100	1.16%
	60%	**6,570,000**	519,675.65	7.910	525,817.65	8.003	6,142.00	0.093	1.18%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2016 Municipal Service Rate and Proposed 2017 Municipal Service Rate

		Rate Code ML	
		Proposed 2016	Proposed 2017
Customer Charge	($)	$1,400.00	$1,500.00
Base Demand First 1,000 kW	($)	$17,240.00	$17,380.00
Additional Demand Charge	($/kW)	$17.24	$17.38
Energy Charge	($/kWh)	$0.04100	$0.04160
Demand Sales Adjustment	($/kW)	-$0.99669	-$0.99669
Fuel Adjustment	($/kWh)	$0.00080	$0.00080

Demand	Load Factor	Usage	Proposed 2016 Amount	Proposed 2016 Unit Cost	Proposed 2017 Amount	Proposed 2017 Unit Cost	Difference Amount	Difference Unit Cost	Difference Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
20,000	**20%**	**2,920,000**	448,322.20	15.354	452,974.20	15.513	4,652.00	0.159	1.04%
	30%	**4,380,000**	509,350.20	11.629	514,878.20	11.755	5,528.00	0.126	1.09%
	40%	**5,840,000**	570,378.20	9.767	576,782.20	9.876	6,404.00	0.110	1.12%
	50%	**7,300,000**	631,406.20	8.649	638,686.20	8.749	7,280.00	0.100	1.15%
	60%	**8,760,000**	692,434.20	7.905	700,590.20	7.998	8,156.00	0.093	1.18%
25,000	**20%**	**3,650,000**	560,052.75	15.344	565,842.75	15.503	5,790.00	0.159	1.03%
	30%	**5,475,000**	636,337.75	11.623	643,222.75	11.748	6,885.00	0.126	1.08%
	40%	**7,300,000**	712,622.75	9.762	720,602.75	9.871	7,980.00	0.109	1.12%
	50%	**9,125,000**	788,907.75	8.646	797,982.75	8.745	9,075.00	0.099	1.15%
	60%	**10,950,000**	865,192.75	7.901	875,362.75	7.994	10,170.00	0.093	1.18%
30,000	**20%**	**4,380,000**	671,783.30	15.338	678,711.30	15.496	6,928.00	0.158	1.03%
	30%	**6,570,000**	763,325.30	11.618	771,567.30	11.744	8,242.00	0.125	1.08%
	40%	**8,760,000**	854,867.30	9.759	864,423.30	9.868	9,556.00	0.109	1.12%
	50%	**10,950,000**	946,409.30	8.643	957,279.30	8.742	10,870.00	0.099	1.15%
	60%	**13,140,000**	1,037,951.30	7.899	1,050,135.30	7.992	12,184.00	0.093	1.17%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Residential Service Rates and Proposed 2018 Residential Service Rates

		Rate Code RG	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$19.50	$21.00
Energy Charge - Summer	($/kWh)	$0.11970	$0.11940
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	54.71	18.235	56.12	18.705	1.41	0.470	2.58%
400	66.44	16.610	67.82	16.955	1.38	0.345	2.08%
500	78.18	15.635	79.53	15.905	1.35	0.270	1.73%
600	89.91	14.985	91.23	15.205	1.32	0.220	1.47%
700	101.65	14.521	102.94	14.705	1.29	0.184	1.27%
800	113.38	14.173	114.64	14.330	1.26	0.158	1.11%
900	125.12	13.902	126.35	14.038	1.23	0.137	0.98%
1,000	136.85	13.685	138.05	13.805	1.20	0.120	0.88%
1,100	148.59	13.508	149.76	13.614	1.17	0.106	0.79%
1,200	160.32	13.360	161.46	13.455	1.14	0.095	0.71%
1,300	172.06	13.235	173.17	13.320	1.11	0.085	0.65%
1,400	183.79	13.128	184.87	13.205	1.08	0.077	0.59%
1,500	195.53	13.035	196.58	13.105	1.05	0.070	0.54%
2,000	254.20	12.710	255.10	12.755	0.90	0.045	0.35%
2,500	312.88	12.515	313.63	12.545	0.75	0.030	0.24%
3,000	371.55	12.385	372.15	12.405	0.60	0.020	0.16%
4,000	488.90	12.223	489.20	12.230	0.30	0.008	0.06%
5,000	606.25	12.125	606.25	12.125	0.00	0.000	0.00%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Residential Service Rates and Proposed 2018 Residential Service Rates

		Rate Code RG	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$19.50	$21.00
Energy Charge - Non Summer	($/kWh)	$0.09970	$0.09940
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	48.42	16.140	49.83	16.610	1.41	0.470	2.91%
400	58.06	14.515	59.44	14.860	1.38	0.345	2.38%
500	67.70	13.540	69.05	13.810	1.35	0.270	1.99%
600	77.34	12.890	78.66	13.110	1.32	0.220	1.71%
700	86.98	12.426	88.27	12.610	1.29	0.184	1.48%
800	96.62	12.078	97.88	12.235	1.26	0.158	1.30%
900	106.26	11.807	107.49	11.943	1.23	0.137	1.16%
1,000	115.90	11.590	117.10	11.710	1.20	0.120	1.04%
1,100	125.54	11.413	126.71	11.519	1.17	0.106	0.93%
1,200	135.18	11.265	136.32	11.360	1.14	0.095	0.84%
1,300	144.82	11.140	145.93	11.225	1.11	0.085	0.77%
1,400	154.46	11.033	155.54	11.110	1.08	0.077	0.70%
1,500	164.10	10.940	165.15	11.010	1.05	0.070	0.64%
2,000	212.30	10.615	213.20	10.660	0.90	0.045	0.42%
2,500	260.50	10.420	261.25	10.450	0.75	0.030	0.29%
3,000	308.70	10.290	309.30	10.310	0.60	0.020	0.19%
4,000	405.10	10.128	405.40	10.135	0.30	0.008	0.07%
5,000	501.50	10.030	501.50	10.030	0.00	0.000	0.00%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Residential Service Rates and Proposed 2018 Residential Service Rates

		Rate Code R2	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$19.50	$21.00
Energy Charge - Summer	($/kWh)	$0.11760	$0.11940
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	54.08	18.025	56.12	18.705	2.04	0.680	3.77%
400	65.60	16.400	67.82	16.955	2.22	0.555	3.38%
500	77.13	15.425	79.53	15.905	2.40	0.480	3.11%
600	88.65	14.775	91.23	15.205	2.58	0.430	2.91%
700	100.18	14.311	102.94	14.705	2.76	0.394	2.76%
800	111.70	13.963	114.64	14.330	2.94	0.368	2.63%
900	123.23	13.692	126.35	14.038	3.12	0.347	2.53%
1,000	134.75	13.475	138.05	13.805	3.30	0.330	2.45%
1,100	146.28	13.298	149.76	13.614	3.48	0.316	2.38%
1,200	157.80	13.150	161.46	13.455	3.66	0.305	2.32%
1,300	169.33	13.025	173.17	13.320	3.84	0.295	2.27%
1,400	180.85	12.918	184.87	13.205	4.02	0.287	2.22%
1,500	192.38	12.825	196.58	13.105	4.20	0.280	2.18%
2,000	250.00	12.500	255.10	12.755	5.10	0.255	2.04%
2,500	307.63	12.305	313.63	12.545	6.00	0.240	1.95%
3,000	365.25	12.175	372.15	12.405	6.90	0.230	1.89%
4,000	480.50	12.013	489.20	12.230	8.70	0.218	1.81%
5,000	595.75	11.915	606.25	12.125	10.50	0.210	1.76%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2017 Residential Service Rates and Proposed 2018 Residential Service Rates

		Rate Code R2	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$19.50	$21.00
Energy Charge - Non Summer	($/kWh)	$0.09760	$0.09940
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	47.79	15.930	49.83	16.610	2.04	0.680	4.27%
400	57.22	14.305	59.44	14.860	2.22	0.555	3.88%
500	66.65	13.330	69.05	13.810	2.40	0.480	3.60%
600	76.08	12.680	78.66	13.110	2.58	0.430	3.39%
700	85.51	12.216	88.27	12.610	2.76	0.394	3.23%
800	94.94	11.868	97.88	12.235	2.94	0.368	3.10%
900	104.37	11.597	107.49	11.943	3.12	0.347	2.99%
1,000	113.80	11.380	117.10	11.710	3.30	0.330	2.90%
1,100	123.23	11.203	126.71	11.519	3.48	0.316	2.82%
1,200	132.66	11.055	136.32	11.360	3.66	0.305	2.76%
1,300	142.09	10.930	145.93	11.225	3.84	0.295	2.70%
1,400	151.52	10.823	155.54	11.110	4.02	0.287	2.65%
1,500	160.95	10.730	165.15	11.010	4.20	0.280	2.61%
2,000	208.10	10.405	213.20	10.660	5.10	0.255	2.45%
2,500	255.25	10.210	261.25	10.450	6.00	0.240	2.35%
3,000	302.40	10.080	309.30	10.310	6.90	0.230	2.28%
4,000	396.70	9.918	405.40	10.135	8.70	0.217	2.19%
5,000	491.00	9.820	501.50	10.030	10.50	0.210	2.14%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Residential Service Rates and Proposed 2018 Residential Service Rates

		Rate Code R4	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$19.50	$21.00
Energy Charge - Summer	($/kWh)	$0.11890	$0.11940
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Proposed 2017		Proposed 2018		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	54.47	18.155	56.12	18.705	1.65	0.550	3.03%
400	66.12	16.530	67.82	16.955	1.70	0.425	2.57%
500	77.78	15.555	79.53	15.905	1.75	0.350	2.25%
600	89.43	14.905	91.23	15.205	1.80	0.300	2.01%
700	101.09	14.441	102.94	14.705	1.85	0.264	1.83%
800	112.74	14.093	114.64	14.330	1.90	0.238	1.69%
900	124.40	13.822	126.35	14.038	1.95	0.217	1.57%
1,000	136.05	13.605	138.05	13.805	2.00	0.200	1.47%
1,100	147.71	13.428	149.76	13.614	2.05	0.186	1.39%
1,200	159.36	13.280	161.46	13.455	2.10	0.175	1.32%
1,300	171.02	13.155	173.17	13.320	2.15	0.165	1.26%
1,400	182.67	13.048	184.87	13.205	2.20	0.157	1.20%
1,500	194.33	12.955	196.58	13.105	2.25	0.150	1.16%
2,000	252.60	12.630	255.10	12.755	2.50	0.125	0.99%
2,500	310.88	12.435	313.63	12.545	2.75	0.110	0.88%
3,000	369.15	12.305	372.15	12.405	3.00	0.100	0.81%
4,000	485.70	12.143	489.20	12.230	3.50	0.088	0.72%
5,000	602.25	12.045	606.25	12.125	4.00	0.080	0.66%

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Comparison of Proposed 2017 Residential Service Rates and Proposed 2018 Residential Service Rates

		Rate Code R4	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$19.50	$21.00
Energy Charge - Non Summer	($/kWh)	$0.09890	$0.09940
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	48.18	16.060	49.83	16.610	1.65	0.550	3.42%
400	57.74	14.435	59.44	14.860	1.70	0.425	2.94%
500	67.30	13.460	69.05	13.810	1.75	0.350	2.60%
600	76.86	12.810	78.66	13.110	1.80	0.300	2.34%
700	86.42	12.346	88.27	12.610	1.85	0.264	2.14%
800	95.98	11.998	97.88	12.235	1.90	0.238	1.98%
900	105.54	11.727	107.49	11.943	1.95	0.217	1.85%
1,000	115.10	11.510	117.10	11.710	2.00	0.200	1.74%
1,100	124.66	11.333	126.71	11.519	2.05	0.186	1.64%
1,200	134.22	11.185	136.32	11.360	2.10	0.175	1.56%
1,300	143.78	11.060	145.93	11.225	2.15	0.165	1.50%
1,400	153.34	10.953	155.54	11.110	2.20	0.157	1.43%
1,500	162.90	10.860	165.15	11.010	2.25	0.150	1.38%
2,000	210.70	10.535	213.20	10.660	2.50	0.125	1.19%
2,500	258.50	10.340	261.25	10.450	2.75	0.110	1.06%
3,000	306.30	10.210	309.30	10.310	3.00	0.100	0.98%
4,000	401.90	10.048	405.40	10.135	3.50	0.088	0.87%
5,000	497.50	9.950	501.50	10.030	4.00	0.080	0.80%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GA	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$25.00	$27.50
Energy Charge - Summer	($/kWh)	$0.11260	$0.11210
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Proposed 2017		Proposed 2018		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	58.08	19.358	60.43	20.142	2.35	0.783	4.05%
400	69.10	17.275	71.40	17.850	2.30	0.575	3.33%
500	80.13	16.025	82.38	16.475	2.25	0.450	2.81%
750	107.69	14.358	109.81	14.642	2.13	0.283	1.97%
1,000	135.25	13.525	137.25	13.725	2.00	0.200	1.48%
2,000	245.50	12.275	247.00	12.350	1.50	0.075	0.61%
3,000	355.75	11.858	356.75	11.892	1.00	0.033	0.28%
4,000	466.00	11.650	466.50	11.663	0.50	0.012	0.11%
5,000	576.25	11.525	576.25	11.525	0.00	0.000	0.00%
6,000	686.50	11.442	686.00	11.433	(0.50)	(0.008)	-0.07%
7,000	796.75	11.382	795.75	11.368	(1.00)	(0.014)	-0.13%
8,000	907.00	11.338	905.50	11.319	(1.50)	(0.019)	-0.17%
9,000	1,017.25	11.303	1,015.25	11.281	(2.00)	(0.022)	-0.20%
10,000	1,127.50	11.275	1,125.00	11.250	(2.50)	(0.025)	-0.22%
11,000	1,237.75	11.252	1,234.75	11.225	(3.00)	(0.027)	-0.24%
12,000	1,348.00	11.233	1,344.50	11.204	(3.50)	(0.029)	-0.26%
13,000	1,458.25	11.217	1,454.25	11.187	(4.00)	(0.031)	-0.27%
14,000	1,568.50	11.204	1,564.00	11.171	(4.50)	(0.032)	-0.29%
15,000	1,678.75	11.192	1,673.75	11.158	(5.00)	(0.033)	-0.30%
20,000	2,230.00	11.150	2,222.50	11.113	(7.50)	(0.037)	-0.34%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GA	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$25.00	$27.50
Energy Charge - Non Summer	($/kWh)	$0.09260	$0.09210
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	51.79	17.263	54.14	18.047	2.35	0.783	4.54%
400	60.72	15.180	63.02	15.755	2.30	0.575	3.79%
500	69.65	13.930	71.90	14.380	2.25	0.450	3.23%
750	91.98	12.263	94.10	12.547	2.13	0.283	2.31%
1,000	114.30	11.430	116.30	11.630	2.00	0.200	1.75%
2,000	203.60	10.180	205.10	10.255	1.50	0.075	0.74%
3,000	292.90	9.763	293.90	9.797	1.00	0.033	0.34%
4,000	382.20	9.555	382.70	9.568	0.50	0.012	0.13%
5,000	471.50	9.430	471.50	9.430	0.00	0.000	0.00%
6,000	560.80	9.347	560.30	9.338	(0.50)	(0.008)	-0.09%
7,000	650.10	9.287	649.10	9.273	(1.00)	(0.014)	-0.15%
8,000	739.40	9.243	737.90	9.224	(1.50)	(0.019)	-0.20%
9,000	828.70	9.208	826.70	9.186	(2.00)	(0.022)	-0.24%
10,000	918.00	9.180	915.50	9.155	(2.50)	(0.025)	-0.27%
11,000	1,007.30	9.157	1,004.30	9.130	(3.00)	(0.027)	-0.30%
12,000	1,096.60	9.138	1,093.10	9.109	(3.50)	(0.029)	-0.32%
13,000	1,185.90	9.122	1,181.90	9.092	(4.00)	(0.031)	-0.34%
14,000	1,275.20	9.109	1,270.70	9.076	(4.50)	(0.032)	-0.35%
15,000	1,364.50	9.097	1,359.50	9.063	(5.00)	(0.033)	-0.37%
20,000	1,811.00	9.055	1,803.50	9.018	(7.50)	(0.037)	-0.41%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GB	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.42	$23.60
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	1,526.60	20.912	1,535.60	21.036	9.00	0.123	0.59%
	30%	10,950	1,691.39	15.447	1,700.39	15.529	9.00	0.082	0.53%
	40%	14,600	1,856.19	12.714	1,865.19	12.775	9.00	0.062	0.48%
	50%	18,250	2,020.99	11.074	2,029.99	11.123	9.00	0.049	0.45%
	60%	21,900	2,185.79	9.981	2,194.79	10.022	9.00	0.041	0.41%
	70%	25,550	2,350.58	9.200	2,359.58	9.235	9.00	0.035	0.38%
	80%	29,200	2,515.38	8.614	2,524.38	8.645	9.00	0.031	0.36%
100	20%	14,600	3,027.19	20.734	3,045.19	20.857	18.00	0.123	0.59%
	30%	21,900	3,356.79	15.328	3,374.79	15.410	18.00	0.082	0.54%
	40%	29,200	3,686.38	12.625	3,704.38	12.686	18.00	0.062	0.49%
	50%	36,500	4,015.98	11.003	4,033.98	11.052	18.00	0.049	0.45%
	60%	43,800	4,345.57	9.921	4,363.57	9.962	18.00	0.041	0.41%
	70%	51,100	4,675.17	9.149	4,693.17	9.184	18.00	0.035	0.39%
	80%	58,400	5,004.76	8.570	5,022.76	8.601	18.00	0.031	0.36%
200	20%	29,200	6,028.38	20.645	6,064.38	20.768	36.00	0.123	0.60%
	30%	43,800	6,687.57	15.268	6,723.57	15.351	36.00	0.082	0.54%
	40%	58,400	7,346.76	12.580	7,382.76	12.642	36.00	0.062	0.49%
	50%	73,000	8,005.95	10.967	8,041.95	11.016	36.00	0.049	0.45%
	60%	87,600	8,665.14	9.892	8,701.14	9.933	36.00	0.041	0.42%
	70%	102,200	9,324.33	9.124	9,360.33	9.159	36.00	0.035	0.39%
	80%	116,800	9,983.52	8.548	10,019.52	8.578	36.00	0.031	0.36%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GB	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.42	$23.60
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand	Load Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	20%	43,800	9,029.57	20.615	9,083.57	20.739	54.00	0.123	0.60%
	30%	65,700	10,018.36	15.249	10,072.36	15.331	54.00	0.082	0.54%
	40%	87,600	11,007.14	12.565	11,061.14	12.627	54.00	0.062	0.49%
	50%	109,500	11,995.93	10.955	12,049.93	11.004	54.00	0.049	0.45%
	60%	131,400	12,984.71	9.882	13,038.71	9.923	54.00	0.041	0.42%
	70%	153,300	13,973.50	9.115	14,027.50	9.150	54.00	0.035	0.39%
	80%	175,200	14,962.28	8.540	15,016.28	8.571	54.00	0.031	0.36%
400	20%	58,400	12,030.76	20.601	12,102.76	20.724	72.00	0.123	0.60%
	30%	87,600	13,349.14	15.239	13,421.14	15.321	72.00	0.082	0.54%
	40%	116,800	14,667.52	12.558	14,739.52	12.619	72.00	0.062	0.49%
	50%	146,000	15,985.90	10.949	16,057.90	10.999	72.00	0.049	0.45%
	60%	175,200	17,304.28	9.877	17,376.28	9.918	72.00	0.041	0.42%
	70%	204,400	18,622.66	9.111	18,694.66	9.146	72.00	0.035	0.39%
	80%	233,600	19,941.04	8.536	20,013.04	8.567	72.00	0.031	0.36%
500	20%	73,000	15,031.95	20.592	15,121.95	20.715	90.00	0.123	0.60%
	30%	109,500	16,679.93	15.233	16,769.93	15.315	90.00	0.082	0.54%
	40%	146,000	18,327.90	12.553	18,417.90	12.615	90.00	0.062	0.49%
	50%	182,500	19,975.88	10.946	20,065.88	10.995	90.00	0.049	0.45%
	60%	219,000	21,623.85	9.874	21,713.85	9.915	90.00	0.041	0.42%
	70%	255,500	23,271.83	9.108	23,361.83	9.144	90.00	0.035	0.39%
	80%	292,000	24,919.80	8.534	25,009.80	8.565	90.00	0.031	0.36%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GB Proposed 2017	Rate Code GB Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.42	$23.60
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

Demand (kW)	Load Factor	Usage (kWh)	Proposed 2017 Amount ($)	Proposed 2017 Unit Cost (Cents/kWh)	Proposed 2018 Amount ($)	Proposed 2018 Unit Cost (Cents/kWh)	Difference Amount ($)	Difference Unit Cost (Cents/kWh)	Difference Percent (%)
50	20%	7,300	1,446.66	19.817	1,455.66	19.941	9.00	0.123	0.62%
	30%	10,950	1,571.49	14.352	1,580.49	14.434	9.00	0.082	0.57%
	40%	14,600	1,696.32	11.619	1,705.32	11.680	9.00	0.062	0.53%
	50%	18,250	1,821.15	9.979	1,830.15	10.028	9.00	0.049	0.49%
	60%	21,900	1,945.98	8.886	1,954.98	8.927	9.00	0.041	0.46%
	70%	25,550	2,070.81	8.105	2,079.81	8.140	9.00	0.035	0.43%
	80%	29,200	2,195.64	7.519	2,204.64	7.550	9.00	0.031	0.41%
100	20%	14,600	2,867.32	19.639	2,885.32	19.762	18.00	0.123	0.63%
	30%	21,900	3,116.98	14.233	3,134.98	14.315	18.00	0.082	0.58%
	40%	29,200	3,366.64	11.530	3,384.64	11.591	18.00	0.062	0.53%
	50%	36,500	3,616.30	9.908	3,634.30	9.957	18.00	0.049	0.50%
	60%	43,800	3,865.96	8.826	3,883.96	8.867	18.00	0.041	0.47%
	70%	51,100	4,115.62	8.054	4,133.62	8.089	18.00	0.035	0.44%
	80%	58,400	4,365.28	7.475	4,383.28	7.506	18.00	0.031	0.41%
200	20%	29,200	5,708.64	19.550	5,744.64	19.673	36.00	0.123	0.63%
	30%	43,800	6,207.96	14.173	6,243.96	14.256	36.00	0.082	0.58%
	40%	58,400	6,707.28	11.485	6,743.28	11.547	36.00	0.062	0.54%
	50%	73,000	7,206.60	9.872	7,242.60	9.921	36.00	0.049	0.50%
	60%	87,600	7,705.92	8.797	7,741.92	8.838	36.00	0.041	0.47%
	70%	102,200	8,205.24	8.029	8,241.24	8.064	36.00	0.035	0.44%
	80%	116,800	8,704.56	7.453	8,740.56	7.483	36.00	0.031	0.41%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GB	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.42	$23.60
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	**20%**	**43,800**	8,549.96	19.520	8,603.96	19.644	54.00	0.123	0.63%
	30%	**65,700**	9,298.94	14.154	9,352.94	14.236	54.00	0.082	0.58%
	40%	**87,600**	10,047.92	11.470	10,101.92	11.532	54.00	0.062	0.54%
	50%	**109,500**	10,796.90	9.860	10,850.90	9.909	54.00	0.049	0.50%
	60%	**131,400**	11,545.88	8.787	11,599.88	8.828	54.00	0.041	0.47%
	70%	**153,300**	12,294.86	8.020	12,348.86	8.055	54.00	0.035	0.44%
	80%	**175,200**	13,043.84	7.445	13,097.84	7.476	54.00	0.031	0.41%
400	**20%**	**58,400**	11,391.28	19.506	11,463.28	19.629	72.00	0.123	0.63%
	30%	**87,600**	12,389.92	14.144	12,461.92	14.226	72.00	0.082	0.58%
	40%	**116,800**	13,388.56	11.463	13,460.56	11.524	72.00	0.062	0.54%
	50%	**146,000**	14,387.20	9.854	14,459.20	9.904	72.00	0.049	0.50%
	60%	**175,200**	15,385.84	8.782	15,457.84	8.823	72.00	0.041	0.47%
	70%	**204,400**	16,384.48	8.016	16,456.48	8.051	72.00	0.035	0.44%
	80%	**233,600**	17,383.12	7.441	17,455.12	7.472	72.00	0.031	0.41%
500	**20%**	**73,000**	14,232.60	19.497	14,322.60	19.620	90.00	0.123	0.63%
	30%	**109,500**	15,480.90	14.138	15,570.90	14.220	90.00	0.082	0.58%
	40%	**146,000**	16,729.20	11.458	16,819.20	11.520	90.00	0.062	0.54%
	50%	**182,500**	17,977.50	9.851	18,067.50	9.900	90.00	0.049	0.50%
	60%	**219,000**	19,225.80	8.779	19,315.80	8.820	90.00	0.041	0.47%
	70%	**255,500**	20,474.10	8.013	20,564.10	8.049	90.00	0.035	0.44%
	80%	**292,000**	21,722.40	7.439	21,812.40	7.470	90.00	0.031	0.41%

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		Rate Code GL	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.60	$23.83
Energy Charge - Summer	($/kWh)	$0.04650	$0.04650
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Load		Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	70%	153,300	13,874.20	9.050	13,943.20	9.095	69.00	0.045	0.50%
	80%	175,200	14,841.08	8.471	14,910.08	8.510	69.00	0.039	0.46%
	90%	197,100	15,807.97	8.020	15,876.97	8.055	69.00	0.035	0.44%
400	70%	204,400	18,490.26	9.046	18,582.26	9.091	92.00	0.045	0.50%
	80%	233,600	19,779.44	8.467	19,871.44	8.507	92.00	0.039	0.47%
	90%	262,800	21,068.62	8.017	21,160.62	8.052	92.00	0.035	0.44%
500	70%	255,500	23,106.33	9.044	23,221.33	9.089	115.00	0.045	0.50%
	80%	292,000	24,717.80	8.465	24,832.80	8.504	115.00	0.039	0.47%
	90%	328,500	26,329.28	8.015	26,444.28	8.050	115.00	0.035	0.44%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GL	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.60	$23.83
Energy Charge - Summer	($/kWh)	$0.04650	$0.04650
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Load		Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
600	**70%**	**306,600**	27,722.39	9.042	27,860.39	9.087	138.00	0.045	0.50%
	80%	**350,400**	29,656.16	8.464	29,794.16	8.503	138.00	0.039	0.47%
	90%	**394,200**	31,589.93	8.014	31,727.93	8.049	138.00	0.035	0.44%
800	**70%**	**408,800**	36,954.52	9.040	37,138.52	9.085	184.00	0.045	0.50%
	80%	**467,200**	39,532.88	8.462	39,716.88	8.501	184.00	0.039	0.47%
	90%	**525,600**	42,111.24	8.012	42,295.24	8.047	184.00	0.035	0.44%
1000	**70%**	**511,000**	46,186.65	9.038	46,416.65	9.083	230.00	0.045	0.50%
	80%	**584,000**	49,409.60	8.461	49,639.60	8.500	230.00	0.039	0.47%
	90%	**657,000**	52,632.55	8.011	52,862.55	8.046	230.00	0.035	0.44%

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		Rate Code GL	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.60	$23.83
Energy Charge - Non Summer	($/kWh)	$0.03650	$0.03650
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	70%	153,300	12,195.56	7.955	12,264.56	8.000	69.00	0.045	0.57%
	80%	175,200	12,922.64	7.376	12,991.64	7.415	69.00	0.039	0.53%
	90%	197,100	13,649.72	6.925	13,718.72	6.960	69.00	0.035	0.51%
400	70%	204,400	16,252.08	7.951	16,344.08	7.996	92.00	0.045	0.57%
	80%	233,600	17,221.52	7.372	17,313.52	7.412	92.00	0.039	0.53%
	90%	262,800	18,190.96	6.922	18,282.96	6.957	92.00	0.035	0.51%
500	70%	255,500	20,308.60	7.949	20,423.60	7.994	115.00	0.045	0.57%
	80%	292,000	21,520.40	7.370	21,635.40	7.409	115.00	0.039	0.53%
	90%	328,500	22,732.20	6.920	22,847.20	6.955	115.00	0.035	0.51%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GL	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$23.60	$23.83
Energy Charge - Non Summer	($/kWh)	$0.03650	$0.03650
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
600	**70%**	**306,600**	24,365.12	7.947	24,503.12	7.992	138.00	0.045	0.57%
	80%	**350,400**	25,819.28	7.369	25,957.28	7.408	138.00	0.039	0.53%
	90%	**394,200**	27,273.44	6.919	27,411.44	6.954	138.00	0.035	0.51%
800	**70%**	**408,800**	32,478.16	7.945	32,662.16	7.990	184.00	0.045	0.57%
	80%	**467,200**	34,417.04	7.367	34,601.04	7.406	184.00	0.039	0.53%
	90%	**525,600**	36,355.92	6.917	36,539.92	6.952	184.00	0.035	0.51%
1000	**70%**	**511,000**	40,591.20	7.943	40,821.20	7.988	230.00	0.045	0.57%
	80%	**584,000**	43,014.80	7.366	43,244.80	7.405	230.00	0.039	0.53%
	90%	**657,000**	45,438.40	6.916	45,668.40	6.951	230.00	0.035	0.51%

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		Rate Code GV	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$25.04	$25.74
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,300	1,607.60	22.022	1,642.60	22.501	35.00	0.479	2.18%
	30%	10,950	1,772.39	16.186	1,807.39	16.506	35.00	0.320	1.97%
	40%	14,600	1,937.19	13.268	1,972.19	13.508	35.00	0.240	1.81%
	50%	18,250	2,101.99	11.518	2,136.99	11.710	35.00	0.192	1.67%
	60%	21,900	2,266.79	10.351	2,301.79	10.510	35.00	0.160	1.54%
	70%	25,550	2,431.58	9.517	2,466.58	9.654	35.00	0.137	1.44%
	80%	29,200	2,596.38	8.892	2,631.38	9.012	35.00	0.120	1.35%
100	20%	14,600	3,189.19	21.844	3,259.19	22.323	70.00	0.479	2.19%
	30%	21,900	3,518.79	16.068	3,588.79	16.387	70.00	0.320	1.99%
	40%	29,200	3,848.38	13.179	3,918.38	13.419	70.00	0.240	1.82%
	50%	36,500	4,177.98	11.447	4,247.98	11.638	70.00	0.192	1.68%
	60%	43,800	4,507.57	10.291	4,577.57	10.451	70.00	0.160	1.55%
	70%	51,100	4,837.17	9.466	4,907.17	9.603	70.00	0.137	1.45%
	80%	58,400	5,166.76	8.847	5,236.76	8.967	70.00	0.120	1.35%
200	20%	29,200	6,352.38	21.755	6,492.38	22.234	140.00	0.479	2.20%
	30%	43,800	7,011.57	16.008	7,151.57	16.328	140.00	0.320	2.00%
	40%	58,400	7,670.76	13.135	7,810.76	13.375	140.00	0.240	1.83%
	50%	73,000	8,329.95	11.411	8,469.95	11.603	140.00	0.192	1.68%
	60%	87,600	8,989.14	10.262	9,129.14	10.421	140.00	0.160	1.56%
	70%	102,200	9,648.33	9.441	9,788.33	9.578	140.00	0.137	1.45%
	80%	116,800	10,307.52	8.825	10,447.52	8.945	140.00	0.120	1.36%

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		Rate Code GV	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$25.04	$25.74
Energy Charge - Summer	($/kWh)	$0.04750	$0.04750
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	**20%**	**43,800**	9,515.57	21.725	9,725.57	22.204	210.00	0.479	2.21%
	30%	**65,700**	10,504.36	15.988	10,714.36	16.308	210.00	0.320	2.00%
	40%	**87,600**	11,493.14	13.120	11,703.14	13.360	210.00	0.240	1.83%
	50%	**109,500**	12,481.93	11.399	12,691.93	11.591	210.00	0.192	1.68%
	60%	**131,400**	13,470.71	10.252	13,680.71	10.411	210.00	0.160	1.56%
	70%	**153,300**	14,459.50	9.432	14,669.50	9.569	210.00	0.137	1.45%
	80%	**175,200**	15,448.28	8.818	15,658.28	8.937	210.00	0.120	1.36%
400	**20%**	**58,400**	12,678.76	21.710	12,958.76	22.190	280.00	0.479	2.21%
	30%	**87,600**	13,997.14	15.978	14,277.14	16.298	280.00	0.320	2.00%
	40%	**116,800**	15,315.52	13.113	15,595.52	13.352	280.00	0.240	1.83%
	50%	**146,000**	16,633.90	11.393	16,913.90	11.585	280.00	0.192	1.68%
	60%	**175,200**	17,952.28	10.247	18,232.28	10.407	280.00	0.160	1.56%
	70%	**204,400**	19,270.66	9.428	19,550.66	9.565	280.00	0.137	1.45%
	80%	**233,600**	20,589.04	8.814	20,869.04	8.934	280.00	0.120	1.36%
500	**20%**	**73,000**	15,841.95	21.701	16,191.95	22.181	350.00	0.479	2.21%
	30%	**109,500**	17,489.93	15.973	17,839.93	16.292	350.00	0.320	2.00%
	40%	**146,000**	19,137.90	13.108	19,487.90	13.348	350.00	0.240	1.83%
	50%	**182,500**	20,785.88	11.390	21,135.88	11.581	350.00	0.192	1.68%
	60%	**219,000**	22,433.85	10.244	22,783.85	10.404	350.00	0.160	1.56%
	70%	**255,500**	24,081.83	9.425	24,431.83	9.562	350.00	0.137	1.45%
	80%	**292,000**	25,729.80	8.812	26,079.80	8.931	350.00	0.120	1.36%

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		Rate Code GV	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$25.04	$25.74
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

Demand (kW)	Load Factor	Usage (kWh)	Proposed 2017 Amount ($)	Proposed 2017 Unit Cost (Cents/kWh)	Proposed 2018 Amount ($)	Proposed 2018 Unit Cost (Cents/kWh)	Difference Amount ($)	Difference Unit Cost (Cents/kWh)	Difference Percent (%)
50	20%	7,300	1,527.66	20.927	1,562.66	21.406	35.00	0.479	2.29%
	30%	10,950	1,652.49	15.091	1,687.49	15.411	35.00	0.320	2.12%
	40%	14,600	1,777.32	12.173	1,812.32	12.413	35.00	0.240	1.97%
	50%	18,250	1,902.15	10.423	1,937.15	10.615	35.00	0.192	1.84%
	60%	21,900	2,026.98	9.256	2,061.98	9.415	35.00	0.160	1.73%
	70%	25,550	2,151.81	8.422	2,186.81	8.559	35.00	0.137	1.63%
	80%	29,200	2,276.64	7.797	2,311.64	7.917	35.00	0.120	1.54%
100	20%	14,600	3,029.32	20.749	3,099.32	21.228	70.00	0.479	2.31%
	30%	21,900	3,278.98	14.973	3,348.98	15.292	70.00	0.320	2.13%
	40%	29,200	3,528.64	12.084	3,598.64	12.324	70.00	0.240	1.98%
	50%	36,500	3,778.30	10.352	3,848.30	10.543	70.00	0.192	1.85%
	60%	43,800	4,027.96	9.196	4,097.96	9.356	70.00	0.160	1.74%
	70%	51,100	4,277.62	8.371	4,347.62	8.508	70.00	0.137	1.64%
	80%	58,400	4,527.28	7.752	4,597.28	7.872	70.00	0.120	1.55%
200	20%	29,200	6,032.64	20.660	6,172.64	21.139	140.00	0.479	2.32%
	30%	43,800	6,531.96	14.913	6,671.96	15.233	140.00	0.320	2.14%
	40%	58,400	7,031.28	12.040	7,171.28	12.280	140.00	0.240	1.99%
	50%	73,000	7,530.60	10.316	7,670.60	10.508	140.00	0.192	1.86%
	60%	87,600	8,029.92	9.167	8,169.92	9.326	140.00	0.160	1.74%
	70%	102,200	8,529.24	8.346	8,669.24	8.483	140.00	0.137	1.64%
	80%	116,800	9,028.56	7.730	9,168.56	7.850	140.00	0.120	1.55%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GV	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$25.04	$25.74
Energy Charge - Non Summer	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	20%	43,800	9,035.96	20.630	9,245.96	21.109	210.00	0.479	2.32%
	30%	65,700	9,784.94	14.893	9,994.94	15.213	210.00	0.320	2.15%
	40%	87,600	10,533.92	12.025	10,743.92	12.265	210.00	0.240	1.99%
	50%	109,500	11,282.90	10.304	11,492.90	10.496	210.00	0.192	1.86%
	60%	131,400	12,031.88	9.157	12,241.88	9.316	210.00	0.160	1.75%
	70%	153,300	12,780.86	8.337	12,990.86	8.474	210.00	0.137	1.64%
	80%	175,200	13,529.84	7.723	13,739.84	7.842	210.00	0.120	1.55%
400	20%	58,400	12,039.28	20.615	12,319.28	21.095	280.00	0.479	2.33%
	30%	87,600	13,037.92	14.883	13,317.92	15.203	280.00	0.320	2.15%
	40%	116,800	14,036.56	12.018	14,316.56	12.257	280.00	0.240	1.99%
	50%	146,000	15,035.20	10.298	15,315.20	10.490	280.00	0.192	1.86%
	60%	175,200	16,033.84	9.152	16,313.84	9.312	280.00	0.160	1.75%
	70%	204,400	17,032.48	8.333	17,312.48	8.470	280.00	0.137	1.64%
	80%	233,600	18,031.12	7.719	18,311.12	7.839	280.00	0.120	1.55%
500	20%	73,000	15,042.60	20.606	15,392.60	21.086	350.00	0.479	2.33%
	30%	109,500	16,290.90	14.878	16,640.90	15.197	350.00	0.320	2.15%
	40%	146,000	17,539.20	12.013	17,889.20	12.253	350.00	0.240	2.00%
	50%	182,500	18,787.50	10.295	19,137.50	10.486	350.00	0.192	1.86%
	60%	219,000	20,035.80	9.149	20,385.80	9.309	350.00	0.160	1.75%
	70%	255,500	21,284.10	8.330	21,634.10	8.467	350.00	0.137	1.64%
	80%	292,000	22,532.40	7.717	22,882.40	7.836	350.00	0.120	1.55%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GT	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$31.00000	$31.00000
Demand Charge - On-Peak	($/kW)	$25.76000	$25.96000
Demand Charge - Off-Peak	($/kW)	$13.94000	$14.58000
Energy Charge - Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

Demand (kW)	Load Factor	Usage (kWh)	Proposed 2017 Amount ($)	Proposed 2017 Unit Cost (Cents/kWh)	Proposed 2018 Amount ($)	Proposed 2018 Unit Cost (Cents/kWh)	Difference Amount ($)	Difference Unit Cost (Cents/kWh)	Difference Percent (%)
50	**20%**	**7,390**	1,100.88	14.897	1,129.47	15.284	28.60	0.387	2.60%
	30%	**11,085**	1,241.64	11.201	1,270.24	11.459	28.60	0.258	2.30%
	40%	**14,780**	1,382.40	9.353	1,411.00	9.547	28.60	0.194	2.07%
	50%	**18,475**	1,523.17	8.244	1,551.77	8.399	28.60	0.155	1.88%
	60%	**22,170**	1,663.93	7.505	1,692.53	7.634	28.60	0.129	1.72%
	70%	**25,865**	1,804.70	6.977	1,833.30	7.088	28.60	0.111	1.58%
	80%	**29,560**	1,945.46	6.581	1,974.06	6.678	28.60	0.097	1.47%
100	**20%**	**14,780**	2,170.75	14.687	2,227.95	15.074	57.20	0.387	2.64%
	30%	**22,170**	2,452.28	11.061	2,509.48	11.319	57.20	0.258	2.33%
	40%	**29,560**	2,733.81	9.248	2,791.01	9.442	57.20	0.194	2.09%
	50%	**36,950**	3,015.34	8.161	3,072.54	8.315	57.20	0.155	1.90%
	60%	**44,340**	3,296.87	7.435	3,354.07	7.564	57.20	0.129	1.73%
	70%	**51,730**	3,578.40	6.917	3,635.60	7.028	57.20	0.111	1.60%
	80%	**59,120**	3,859.93	6.529	3,917.13	6.626	57.20	0.097	1.48%
200	**20%**	**29,560**	4,310.50	14.582	4,424.90	14.969	114.40	0.387	2.65%
	30%	**44,340**	4,873.56	10.991	4,987.96	11.249	114.40	0.258	2.35%
	40%	**59,120**	5,436.62	9.196	5,551.02	9.389	114.40	0.194	2.10%
	50%	**73,900**	5,999.68	8.119	6,114.08	8.273	114.40	0.155	1.91%
	60%	**88,680**	6,562.74	7.400	6,677.13	7.529	114.40	0.129	1.74%
	70%	**103,460**	7,125.79	6.887	7,240.19	6.998	114.40	0.111	1.61%
	80%	**118,240**	7,688.85	6.503	7,803.25	6.600	114.40	0.097	1.49%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GT	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$31.00000	$31.00000
Demand Charge - On-Peak	($/kW)	$25.76000	$25.96000
Demand Charge - Off-Peak	($/kW)	$13.94000	$14.58000
Energy Charge - Summer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Summer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**44,340**	6,450.25	14.547	6,621.85	14.934	171.60	0.387	2.66%
	30%	**66,510**	7,294.84	10.968	7,466.44	11.226	171.60	0.258	2.35%
	40%	**88,680**	8,139.43	9.178	8,311.03	9.372	171.60	0.194	2.11%
	50%	**110,850**	8,984.02	8.105	9,155.61	8.259	171.60	0.155	1.91%
	60%	**133,020**	9,828.60	7.389	10,000.20	7.518	171.60	0.129	1.75%
	70%	**155,190**	10,673.19	6.877	10,844.79	6.988	171.60	0.111	1.61%
	80%	**177,360**	11,517.78	6.494	11,689.38	6.591	171.60	0.097	1.49%
400	**20%**	**59,120**	8,590.00	14.530	8,818.80	14.917	228.80	0.387	2.66%
	30%	**88,680**	9,716.12	10.956	9,944.92	11.214	228.80	0.258	2.35%
	40%	**118,240**	10,842.24	9.170	11,071.03	9.363	228.80	0.194	2.11%
	50%	**147,800**	11,968.35	8.098	12,197.15	8.252	228.80	0.155	1.91%
	60%	**177,360**	13,094.47	7.383	13,323.27	7.512	228.80	0.129	1.75%
	70%	**206,920**	14,220.59	6.873	14,449.39	6.983	228.80	0.111	1.61%
	80%	**236,480**	15,346.71	6.490	15,575.50	6.586	228.80	0.097	1.49%
500	**20%**	**73,900**	10,729.75	14.519	11,015.75	14.906	286.00	0.387	2.67%
	30%	**110,850**	12,137.40	10.949	12,423.40	11.207	286.00	0.258	2.36%
	40%	**147,800**	13,545.05	9.164	13,831.04	9.358	286.00	0.194	2.11%
	50%	**184,750**	14,952.69	8.093	15,238.69	8.248	286.00	0.155	1.91%
	60%	**221,700**	16,360.34	7.379	16,646.34	7.508	286.00	0.129	1.75%
	70%	**258,650**	17,767.99	6.870	18,053.98	6.980	286.00	0.111	1.61%
	80%	**295,600**	19,175.63	6.487	19,461.63	6.584	286.00	0.097	1.49%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GT	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$31.00	$31.00
Demand Charge - On-Peak	($/kW)	$25.76	$25.96
Demand Charge - Off-Peak	($/kW)	$13.94	$14.58
Energy Charge - Nonsummer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Nonsummer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	**20%**	**7,390**	1,068.28	14.456	1,097.67	14.854	29.39	0.398	2.75%
	30%	**11,085**	1,203.41	10.856	1,232.80	11.121	29.39	0.265	2.44%
	40%	**14,780**	1,338.53	9.056	1,367.93	9.255	29.39	0.199	2.20%
	50%	**18,475**	1,473.66	7.976	1,503.05	8.136	29.39	0.159	1.99%
	60%	**22,170**	1,608.78	7.257	1,638.18	7.389	29.39	0.133	1.83%
	70%	**25,865**	1,743.91	6.742	1,773.30	6.856	29.39	0.114	1.69%
	80%	**29,560**	1,879.03	6.357	1,908.43	6.456	29.39	0.099	1.56%
100	**20%**	**14,780**	2,105.56	14.246	2,164.35	14.644	58.79	0.398	2.79%
	30%	**22,170**	2,375.81	10.716	2,434.60	10.982	58.79	0.265	2.47%
	40%	**29,560**	2,646.06	8.952	2,704.85	9.150	58.79	0.199	2.22%
	50%	**36,950**	2,916.32	7.893	2,975.10	8.052	58.79	0.159	2.02%
	60%	**44,340**	3,186.57	7.187	3,245.35	7.319	58.79	0.133	1.84%
	70%	**51,730**	3,456.82	6.682	3,515.60	6.796	58.79	0.114	1.70%
	80%	**59,120**	3,727.07	6.304	3,785.86	6.404	58.79	0.099	1.58%
200	**20%**	**29,560**	4,180.12	14.141	4,297.70	14.539	117.57	0.398	2.81%
	30%	**44,340**	4,720.63	10.646	4,838.20	10.912	117.57	0.265	2.49%
	40%	**59,120**	5,261.13	8.899	5,378.70	9.098	117.57	0.199	2.23%
	50%	**73,900**	5,801.63	7.851	5,919.20	8.010	117.57	0.159	2.03%
	60%	**88,680**	6,342.13	7.152	6,459.71	7.284	117.57	0.133	1.85%
	70%	**103,460**	6,882.64	6.652	7,000.21	6.766	117.57	0.114	1.71%
	80%	**118,240**	7,423.14	6.278	7,540.71	6.377	117.57	0.099	1.58%

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Comparison of Proposed 2017 General Service Rates and Proposed 2018 General Service Rates

		Rate Code GT	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$31.00	$31.00
Demand Charge - On-Peak	($/kW)	$25.76	$25.96
Demand Charge - Off-Peak	($/kW)	$13.94	$14.58
Energy Charge - Nonsummer On-Peak	($/kWh)	$0.04750	$0.04750
Energy Charge - Nonsummer Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**44,340**	6,254.68	14.106	6,431.04	14.504	176.36	0.398	2.82%
	30%	**66,510**	7,065.44	10.623	7,241.80	10.888	176.36	0.265	2.50%
	40%	**88,680**	7,876.19	8.882	8,052.55	9.080	176.36	0.199	2.24%
	50%	**110,850**	8,686.95	7.837	8,863.30	7.996	176.36	0.159	2.03%
	60%	**133,020**	9,497.70	7.140	9,674.06	7.273	176.36	0.133	1.86%
	70%	**155,190**	10,308.45	6.642	10,484.81	6.756	176.36	0.114	1.71%
	80%	**177,360**	11,119.21	6.269	11,295.57	6.369	176.36	0.099	1.59%
400	**20%**	**59,120**	8,329.25	14.089	8,564.39	14.486	235.15	0.398	2.82%
	30%	**88,680**	9,410.25	10.611	9,645.40	10.877	235.15	0.265	2.50%
	40%	**118,240**	10,491.26	8.873	10,726.40	9.072	235.15	0.199	2.24%
	50%	**147,800**	11,572.26	7.830	11,807.41	7.989	235.15	0.159	2.03%
	60%	**177,360**	12,653.27	7.134	12,888.41	7.267	235.15	0.133	1.86%
	70%	**206,920**	13,734.27	6.637	13,969.42	6.751	235.15	0.114	1.71%
	80%	**236,480**	14,815.28	6.265	15,050.42	6.364	235.15	0.099	1.59%
500	**20%**	**73,900**	10,403.81	14.078	10,697.74	14.476	293.93	0.398	2.83%
	30%	**110,850**	11,755.06	10.604	12,049.00	10.870	293.93	0.265	2.50%
	40%	**147,800**	13,106.32	8.868	13,400.25	9.066	293.93	0.199	2.24%
	50%	**184,750**	14,457.58	7.825	14,751.51	7.985	293.93	0.159	2.03%
	60%	**221,700**	15,808.83	7.131	16,102.76	7.263	293.93	0.133	1.86%
	70%	**258,650**	17,160.09	6.634	17,454.02	6.748	293.93	0.114	1.71%
	80%	**295,600**	18,511.35	6.262	18,805.28	6.362	293.93	0.099	1.59%

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Comparison of Proposed 2017 Temporary Service Rates and Proposed 2018 Temporary Service Rates

		Rate Code TP	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$22.00	$23.00
Energy Charge - Summer	($/kWh)	$0.14120	$0.14680
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Proposed 2017		Proposed 2018		Difference		
Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	63.66	21.218	66.34	22.112	2.68	0.893	4.21%
400	77.54	19.385	80.78	20.195	3.24	0.810	4.18%
500	91.43	18.285	95.23	19.045	3.80	0.760	4.16%
750	126.14	16.818	131.34	17.512	5.20	0.693	4.12%
1,000	160.85	16.085	167.45	16.745	6.60	0.660	4.10%
2,000	299.70	14.985	311.90	15.595	12.20	0.610	4.07%
3,000	438.55	14.618	456.35	15.212	17.80	0.593	4.06%
4,000	577.40	14.435	600.80	15.020	23.40	0.585	4.05%
5,000	716.25	14.325	745.25	14.905	29.00	0.580	4.05%
6,000	855.10	14.252	889.70	14.828	34.60	0.577	4.05%
7,000	993.95	14.199	1,034.15	14.774	40.20	0.574	4.04%
8,000	1,132.80	14.160	1,178.60	14.733	45.80	0.573	4.04%
9,000	1,271.65	14.129	1,323.05	14.701	51.40	0.571	4.04%
10,000	1,410.50	14.105	1,467.50	14.675	57.00	0.570	4.04%
11,000	1,549.35	14.085	1,611.95	14.654	62.60	0.569	4.04%
12,000	1,688.20	14.068	1,756.40	14.637	68.20	0.568	4.04%
13,000	1,827.05	14.054	1,900.85	14.622	73.80	0.568	4.04%
14,000	1,965.90	14.042	2,045.30	14.609	79.40	0.567	4.04%
15,000	2,104.75	14.032	2,189.75	14.598	85.00	0.567	4.04%
20,000	2,799.00	13.995	2,912.00	14.560	113.00	0.565	4.04%

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Comparison of Proposed 2017 Temporary Service Rates and Proposed 2018 Temporary Service Rates

		Rate Code TP	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$22.00	$23.00
Energy Charge - Non Summer	($/kWh)	$0.12120	$0.12680
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Proposed 2017		Proposed 2018		Difference		
Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
300	57.37	19.123	60.05	20.017	2.68	0.893	4.67%
400	69.16	17.290	72.40	18.100	3.24	0.810	4.68%
500	80.95	16.190	84.75	16.950	3.80	0.760	4.69%
750	110.43	14.723	115.63	15.417	5.20	0.693	4.71%
1,000	139.90	13.990	146.50	14.650	6.60	0.660	4.72%
2,000	257.80	12.890	270.00	13.500	12.20	0.610	4.73%
3,000	375.70	12.523	393.50	13.117	17.80	0.593	4.74%
4,000	493.60	12.340	517.00	12.925	23.40	0.585	4.74%
5,000	611.50	12.230	640.50	12.810	29.00	0.580	4.74%
6,000	729.40	12.157	764.00	12.733	34.60	0.577	4.74%
7,000	847.30	12.104	887.50	12.679	40.20	0.574	4.74%
8,000	965.20	12.065	1,011.00	12.638	45.80	0.572	4.75%
9,000	1,083.10	12.034	1,134.50	12.606	51.40	0.571	4.75%
10,000	1,201.00	12.010	1,258.00	12.580	57.00	0.570	4.75%
11,000	1,318.90	11.990	1,381.50	12.559	62.60	0.569	4.75%
12,000	1,436.80	11.973	1,505.00	12.542	68.20	0.568	4.75%
13,000	1,554.70	11.959	1,628.50	12.527	73.80	0.568	4.75%
14,000	1,672.60	11.947	1,752.00	12.514	79.40	0.567	4.75%
15,000	1,790.50	11.937	1,875.50	12.503	85.00	0.567	4.75%
20,000	2,380.00	11.900	2,493.00	12.465	113.00	0.565	4.75%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Transition Adjustment and Proposed 2018 Transition Adjustment

		Rate Code TA	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$12.65	$15.46
Energy Charge - Summer	($/kWh)	$0.07000	$0.06438
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
50	20%	7,300	1,152.19	15.783	1,251.57	17.145	99.38	1.361	8.63%
	30%	10,950	1,398.99	12.776	1,477.96	13.497	78.97	0.721	5.64%
	40%	14,600	1,645.91	11.273	1,704.35	11.674	58.44	0.400	3.55%
	50%	18,250	1,892.84	10.372	1,930.74	10.579	37.90	0.208	2.00%
	60%	21,900	2,139.76	9.771	2,157.13	9.850	17.37	0.079	0.81%
	70%	25,550	2,386.68	9.341	2,383.52	9.329	(3.16)	(0.012)	-0.13%
	80%	29,200	2,633.60	9.019	2,609.91	8.938	(23.69)	(0.081)	-0.90%
100	20%	14,600	2,278.14	15.604	2,477.13	16.967	199.00	1.363	8.73%
	30%	21,900	2,771.98	12.657	2,929.91	13.379	157.93	0.721	5.70%
	40%	29,200	3,265.83	11.184	3,382.70	11.585	116.87	0.400	3.58%
	50%	36,500	3,759.67	10.300	3,835.48	10.508	75.81	0.208	2.02%
	60%	43,800	4,253.52	9.711	4,288.26	9.791	34.75	0.079	0.82%
	70%	51,100	4,747.36	9.290	4,741.04	9.278	(6.32)	(0.012)	-0.13%
	80%	58,400	5,241.21	8.975	5,193.83	8.894	(47.38)	(0.081)	-0.90%
200	20%	29,200	4,530.27	15.515	4,928.26	16.878	397.99	1.363	8.79%
	30%	43,800	5,517.96	12.598	5,833.83	13.319	315.87	0.721	5.72%
	40%	58,400	6,505.65	11.140	6,739.39	11.540	233.74	0.400	3.59%
	50%	73,000	7,493.34	10.265	7,644.96	10.473	151.62	0.208	2.02%
	60%	87,600	8,481.03	9.682	8,550.52	9.761	69.49	0.079	0.82%
	70%	102,200	9,468.72	9.265	9,456.09	9.253	(12.63)	(0.012)	-0.13%
	80%	116,800	10,456.41	8.952	10,361.65	8.871	(94.76)	(0.081)	-0.91%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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Comparison of Proposed 2017 Transition Adjustment and Proposed 2018 Transition Adjustment

		Rate Code TA	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$12.65	$15.46
Energy Charge - Summer	($/kWh)	$0.07000	$0.06438
Demand Sales Adjustment	($/kWh)	-$0.00235	-$0.00235
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

	Load		Proposed 2017		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	20%	43,800	6,782.41	15.485	7,379.39	16.848	596.99	1.363	8.80%
	30%	65,700	8,263.94	12.578	8,737.74	13.299	473.80	0.721	5.73%
	40%	87,600	9,745.48	11.125	10,096.09	11.525	350.61	0.400	3.60%
	50%	109,500	11,227.01	10.253	11,454.43	10.461	227.42	0.208	2.03%
	60%	131,400	12,708.55	9.672	12,812.78	9.751	104.24	0.079	0.82%
	70%	153,300	14,190.08	9.256	14,171.13	9.244	(18.95)	(0.012)	-0.13%
	80%	175,200	15,671.62	8.945	15,529.48	8.864	(142.14)	(0.081)	-0.91%
400	20%	58,400	9,034.54	15.470	9,830.52	16.833	795.98	1.363	8.81%
	30%	87,600	11,009.92	12.568	11,641.65	13.290	631.73	0.721	5.74%
	40%	116,800	12,985.30	11.118	13,452.78	11.518	467.48	0.400	3.60%
	50%	146,000	14,960.68	10.247	15,263.91	10.455	303.23	0.208	2.03%
	60%	175,200	16,936.06	9.667	17,075.04	9.746	138.98	0.079	0.82%
	70%	204,400	18,911.44	9.252	18,886.17	9.240	(25.27)	(0.012)	-0.13%
	80%	233,600	20,886.82	8.941	20,697.30	8.860	(189.52)	(0.081)	-0.91%
500	20%	73,000	11,286.68	15.461	12,281.65	16.824	994.98	1.363	8.82%
	30%	109,500	13,755.90	12.562	14,545.56	13.284	789.66	0.721	5.74%
	40%	146,000	16,225.13	11.113	16,809.48	11.513	584.35	0.400	3.60%
	50%	182,500	18,694.35	10.243	19,073.39	10.451	379.04	0.208	2.03%
	60%	219,000	21,163.58	9.664	21,337.30	9.743	173.73	0.079	0.82%
	70%	255,500	23,632.80	9.250	23,601.21	9.237	(31.59)	(0.012)	-0.13%
	80%	292,000	26,102.03	8.939	25,865.13	8.858	(236.90)	(0.081)	-0.91%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Transition Adjustment and Proposed 2018 Transition Adjustment

		Rate Code TA	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$12.65	$15.46
Energy Charge - Nonsummer	($/kWh)	$0.06000	$0.05438
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
50	20%	7,300	1,072.09	14.686	1,171.75	16.051	99.66	1.365	9.30%
	30%	10,950	1,279.05	11.681	1,358.17	12.403	79.12	0.723	6.19%
	40%	14,600	1,486.00	10.178	1,544.60	10.579	58.59	0.401	3.94%
	50%	18,250	1,692.96	9.276	1,731.02	9.485	38.06	0.209	2.25%
	60%	21,900	1,899.91	8.675	1,917.44	8.755	17.53	0.080	0.92%
	70%	25,550	2,106.87	8.246	2,103.87	8.234	(3.00)	(0.012)	-0.14%
	80%	29,200	2,313.82	7.924	2,290.29	7.843	(23.53)	(0.081)	-1.02%
100	20%	14,600	2,118.19	14.508	2,317.50	15.873	199.31	1.365	9.41%
	30%	21,900	2,532.10	11.562	2,690.34	12.285	158.25	0.723	6.25%
	40%	29,200	2,946.01	10.089	3,063.19	10.490	117.19	0.401	3.98%
	50%	36,500	3,359.92	9.205	3,436.04	9.414	76.12	0.209	2.27%
	60%	43,800	3,773.83	8.616	3,808.89	8.696	35.06	0.080	0.93%
	70%	51,100	4,187.74	8.195	4,181.73	8.183	(6.00)	(0.012)	-0.14%
	80%	58,400	4,601.65	7.880	4,554.58	7.799	(47.07)	(0.081)	-1.02%
200	20%	29,200	4,210.37	14.419	4,608.99	15.784	398.62	1.365	9.47%
	30%	43,800	5,038.19	11.503	5,354.69	12.225	316.50	0.723	6.28%
	40%	58,400	5,866.01	10.045	6,100.38	10.446	234.37	0.401	4.00%
	50%	73,000	6,693.83	9.170	6,846.08	9.378	152.25	0.209	2.27%
	60%	87,600	7,521.65	8.586	7,591.77	8.666	70.12	0.080	0.93%
	70%	102,200	8,349.47	8.170	8,337.47	8.158	(12.00)	(0.012)	-0.14%
	80%	116,800	9,177.29	7.857	9,083.16	7.777	(94.13)	(0.081)	-1.03%

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Comparison of Proposed 2017 Transition Adjustment and Proposed 2018 Transition Adjustment

		Rate Code TA	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$26.00	$26.00
Demand Charge	($/kW)	$12.65	$15.46
Energy Charge - Nonsummer	($/kWh)	$0.06000	$0.05438
Demand Sales Adjustment	($/kWh)	-$0.00315	-$0.00315
Fuel Adjustment	($/kWh)	-$0.00015	-$0.00015

	Load		Existing GA		Proposed 2018		Difference		
Demand	Factor	Usage	Amount	Unit Cost	Amount	Unit Cost	Amount	Unit Cost	Percent
(kW)		(kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	($)	(Cents/kWh)	(%)
300	**20%**	**43,800**	6,302.56	14.389	6,900.49	15.755	597.93	1.365	9.49%
	30%	**65,700**	7,544.29	11.483	8,019.03	12.206	474.74	0.723	6.29%
	40%	**87,600**	8,786.02	10.030	9,137.57	10.431	351.55	0.401	4.00%
	50%	**109,500**	10,027.75	9.158	10,256.11	9.366	228.37	0.209	2.28%
	60%	**131,400**	11,269.48	8.576	11,374.66	8.657	105.18	0.080	0.93%
	70%	**153,300**	12,511.21	8.161	12,493.20	8.150	(18.01)	(0.012)	-0.14%
	80%	**175,200**	13,752.94	7.850	13,611.74	7.769	(141.20)	(0.081)	-1.03%
400	**20%**	**58,400**	8,394.74	14.375	9,191.98	15.740	797.24	1.365	9.50%
	30%	**87,600**	10,050.38	11.473	10,683.37	12.196	632.99	0.723	6.30%
	40%	**116,800**	11,706.02	10.022	12,174.76	10.424	468.74	0.401	4.00%
	50%	**146,000**	13,361.66	9.152	13,666.15	9.360	304.49	0.209	2.28%
	60%	**175,200**	15,017.30	8.572	15,157.54	8.652	140.24	0.080	0.93%
	70%	**204,400**	16,672.94	8.157	16,648.93	8.145	(24.01)	(0.012)	-0.14%
	80%	**233,600**	18,328.58	7.846	18,140.32	7.766	(188.26)	(0.081)	-1.03%
500	**20%**	**73,000**	10,486.93	14.366	11,483.48	15.731	996.55	1.365	9.50%
	30%	**109,500**	12,556.48	11.467	13,347.71	12.190	791.24	0.723	6.30%
	40%	**146,000**	14,626.03	10.018	15,211.95	10.419	585.92	0.401	4.01%
	50%	**182,500**	16,695.58	9.148	17,076.19	9.357	380.61	0.209	2.28%
	60%	**219,000**	18,765.13	8.569	18,940.43	8.649	175.30	0.080	0.93%
	70%	**255,500**	20,834.68	8.154	20,804.66	8.143	(30.01)	(0.012)	-0.14%
	80%	**292,000**	22,904.23	7.844	22,668.90	7.763	(235.33)	(0.081)	-1.03%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
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2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Industrial Service Rate and Proposed 2018 Industrial Service Rate

		Rate Code L	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$3,400.00	$3,400.00
Base Demand First 300 kW	($)	$7,511.40	$7,663.50
Additional Demand Charge	($/kW)	$19.26	$19.65
Energy Charge - On-Peak	($/kWh)	$0.05750	$0.05750
Energy Charge - Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kW)	-$1.03338	-$1.03338
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
1,000	**20%**	**146,000**	29,349.43	20.102	29,774.53	20.394	425.10	0.291	1.45%
	30%	**219,000**	32,189.13	14.698	32,614.23	14.892	425.10	0.194	1.32%
	40%	**292,000**	35,028.83	11.996	35,453.93	12.142	425.10	0.146	1.21%
	50%	**365,000**	37,868.53	10.375	38,293.63	10.491	425.10	0.116	1.12%
	60%	**438,000**	40,708.23	9.294	41,133.33	9.391	425.10	0.097	1.04%
	70%	**511,000**	43,547.93	8.522	43,973.03	8.605	425.10	0.083	0.98%
	80%	**584,000**	46,387.63	7.943	46,812.73	8.016	425.10	0.073	0.92%
1,500	**20%**	**219,000**	41,302.44	18.860	41,922.54	19.143	620.10	0.283	1.50%
	30%	**328,500**	45,561.99	13.870	46,182.09	14.058	620.10	0.189	1.36%
	40%	**438,000**	49,821.54	11.375	50,441.64	11.516	620.10	0.142	1.24%
	50%	**547,500**	54,081.09	9.878	54,701.19	9.991	620.10	0.113	1.15%
	60%	**657,000**	58,340.64	8.880	58,960.74	8.974	620.10	0.094	1.06%
	70%	**766,500**	62,600.19	8.167	63,220.29	8.248	620.10	0.081	0.99%
	80%	**876,000**	66,859.74	7.632	67,479.84	7.703	620.10	0.071	0.93%
2,000	**20%**	**292,000**	53,255.45	18.238	54,070.55	18.517	815.10	0.279	1.53%
	30%	**438,000**	58,934.85	13.455	59,749.95	13.642	815.10	0.186	1.38%
	40%	**584,000**	64,614.25	11.064	65,429.35	11.204	815.10	0.140	1.26%
	50%	**730,000**	70,293.65	9.629	71,108.75	9.741	815.10	0.112	1.16%
	60%	**876,000**	75,973.05	8.673	76,788.15	8.766	815.10	0.093	1.07%
	70%	**1,022,000**	81,652.45	7.989	82,467.55	8.069	815.10	0.080	1.00%
	80%	**1,168,000**	87,331.85	7.477	88,146.95	7.547	815.10	0.070	0.93%

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Comparison of Proposed 2017 Industrial Service Rate and Proposed 2018 Industrial Service Rate

		Rate Code L	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$3,400.00	$3,400.00
Base Demand First 300 kW	($)	$7,511.40	$7,663.50
Additional Demand Charge	($/kW)	$19.26	$19.65
Energy Charge - On-Peak	($/kWh)	$0.05750	$0.05750
Energy Charge - Off-Peak	($/kWh)	$0.03750	$0.03750
Demand Sales Adjustment	($/kW)	-$1.03338	-$1.03338
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
3,000	**20%**	**438,000**	77,161.47	17.617	78,366.57	17.892	1,205.10	0.275	1.56%
	30%	**657,000**	85,680.57	13.041	86,885.67	13.225	1,205.10	0.183	1.41%
	40%	**876,000**	94,199.67	10.753	95,404.77	10.891	1,205.10	0.138	1.28%
	50%	**1,095,000**	102,718.77	9.381	103,923.87	9.491	1,205.10	0.110	1.17%
	60%	**1,314,000**	111,237.87	8.466	112,442.97	8.557	1,205.10	0.092	1.08%
	70%	**1,533,000**	119,756.97	7.812	120,962.07	7.891	1,205.10	0.079	1.01%
	80%	**1,752,000**	128,276.07	7.322	129,481.17	7.390	1,205.10	0.069	0.94%
4,000	**20%**	**584,000**	101,067.49	17.306	102,662.59	17.579	1,595.10	0.273	1.58%
	30%	**876,000**	112,426.29	12.834	114,021.39	13.016	1,595.10	0.182	1.42%
	40%	**1,168,000**	123,785.09	10.598	125,380.19	10.735	1,595.10	0.137	1.29%
	50%	**1,460,000**	135,143.89	9.256	136,738.99	9.366	1,595.10	0.109	1.18%
	60%	**1,752,000**	146,502.69	8.362	148,097.79	8.453	1,595.10	0.091	1.09%
	70%	**2,044,000**	157,861.49	7.723	159,456.59	7.801	1,595.10	0.078	1.01%
	80%	**2,336,000**	169,220.29	7.244	170,815.39	7.312	1,595.10	0.068	0.94%
5,000	**20%**	**730,000**	124,973.51	17.120	126,958.61	17.392	1,985.10	0.272	1.59%
	30%	**1,095,000**	139,172.01	12.710	141,157.11	12.891	1,985.10	0.181	1.43%
	40%	**1,460,000**	153,370.51	10.505	155,355.61	10.641	1,985.10	0.136	1.29%
	50%	**1,825,000**	167,569.01	9.182	169,554.11	9.291	1,985.10	0.109	1.18%
	60%	**2,190,000**	181,767.51	8.300	183,752.61	8.391	1,985.10	0.091	1.09%
	70%	**2,555,000**	195,966.01	7.670	197,951.11	7.748	1,985.10	0.078	1.01%
	80%	**2,920,000**	210,164.51	7.197	212,149.61	7.265	1,985.10	0.068	0.94%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Municipal Service Rate and Proposed 2018 Municipal Service Rate

		Rate Code ML	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$1,500.00	$1,500.00
Base Demand First 1,000 kW	($)	$17,380.00	$18,180.00
Additional Demand Charge	($/kW)	$17.38	$18.18
Energy Charge	($/kWh)	$0.04160	$0.04160
Demand Sales Adjustment	($/kW)	-$1.03338	-$1.03338
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
5,000	**20%**	**730,000**	113,601.10	15.562	117,601.10	16.110	4,000.00	0.548	3.52%
	30%	**1,095,000**	128,785.10	11.761	132,785.10	12.126	4,000.00	0.365	3.11%
	40%	**1,460,000**	143,969.10	9.861	147,969.10	10.135	4,000.00	0.274	2.78%
	50%	**1,825,000**	159,153.10	8.721	163,153.10	8.940	4,000.00	0.219	2.51%
	60%	**2,190,000**	174,337.10	7.961	178,337.10	8.143	4,000.00	0.183	2.29%
10,000	**20%**	**1,460,000**	225,702.20	15.459	233,702.20	16.007	8,000.00	0.548	3.54%
	30%	**2,190,000**	256,070.20	11.693	264,070.20	12.058	8,000.00	0.365	3.12%
	40%	**2,920,000**	286,438.20	9.810	294,438.20	10.084	8,000.00	0.274	2.79%
	50%	**3,650,000**	316,806.20	8.680	324,806.20	8.899	8,000.00	0.219	2.53%
	60%	**4,380,000**	347,174.20	7.926	355,174.20	8.109	8,000.00	0.183	2.30%
15,000	**20%**	**2,190,000**	337,803.30	15.425	349,803.30	15.973	12,000.00	0.548	3.55%
	30%	**3,285,000**	383,355.30	11.670	395,355.30	12.035	12,000.00	0.365	3.13%
	40%	**4,380,000**	428,907.30	9.792	440,907.30	10.066	12,000.00	0.274	2.80%
	50%	**5,475,000**	474,459.30	8.666	486,459.30	8.885	12,000.00	0.219	2.53%
	60%	**6,570,000**	520,011.30	7.915	532,011.30	8.098	12,000.00	0.183	2.31%

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(Santee Cooper)
2015 Electric Cost of Service Rate Study

Comparison of Proposed 2017 Municipal Service Rate and Proposed 2018 Municipal Service Rate

		Rate Code ML	
		Proposed 2017	Proposed 2018
Customer Charge	($)	$1,500.00	$1,500.00
Base Demand First 1,000 kW	($)	$17,380.00	$18,180.00
Additional Demand Charge	($/kW)	$17.38	$18.18
Energy Charge	($/kWh)	$0.04160	$0.04160
Demand Sales Adjustment	($/kW)	-$1.03338	-$1.03338
Fuel Adjustment	($/kWh)	$0.00000	$0.00000

			Proposed 2017		Proposed 2018		Difference		
Demand (kW)	Load Factor	Usage (kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Amount ($)	Unit Cost (Cents/kWh)	Percent (%)
20,000	**20%**	**2,920,000**	449,904.40	15.408	465,904.40	15.956	16,000.00	0.548	3.56%
	30%	**4,380,000**	510,640.40	11.658	526,640.40	12.024	16,000.00	0.365	3.13%
	40%	**5,840,000**	571,376.40	9.784	587,376.40	10.058	16,000.00	0.274	2.80%
	50%	**7,300,000**	632,112.40	8.659	648,112.40	8.878	16,000.00	0.219	2.53%
	60%	**8,760,000**	692,848.40	7.909	708,848.40	8.092	16,000.00	0.183	2.31%
25,000	**20%**	**3,650,000**	562,005.50	15.397	582,005.50	15.945	20,000.00	0.548	3.56%
	30%	**5,475,000**	637,925.50	11.652	657,925.50	12.017	20,000.00	0.365	3.14%
	40%	**7,300,000**	713,845.50	9.779	733,845.50	10.053	20,000.00	0.274	2.80%
	50%	**9,125,000**	789,765.50	8.655	809,765.50	8.874	20,000.00	0.219	2.53%
	60%	**10,950,000**	865,685.50	7.906	885,685.50	8.088	20,000.00	0.183	2.31%
30,000	**20%**	**4,380,000**	674,106.60	15.391	698,106.60	15.939	24,000.00	0.548	3.56%
	30%	**6,570,000**	765,210.60	11.647	789,210.60	12.012	24,000.00	0.365	3.14%
	40%	**8,760,000**	856,314.60	9.775	880,314.60	10.049	24,000.00	0.274	2.80%
	50%	**10,950,000**	947,418.60	8.652	971,418.60	8.871	24,000.00	0.219	2.53%
	60%	**13,140,000**	1,038,522.60	7.904	1,062,522.60	8.086	24,000.00	0.183	2.31%

Appendix B
RATE SCHEDULES

APPENDIX B

2016 RATE SCHEDULES

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL
GENERAL SERVICE
SCHEDULE RG-16

Section 1. Availability:

This schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable for use in private residences, single-family dwelling units, and farms. Energy and power delivered to each residence, dwelling unit, or farm shall be separately metered, and shall include energy used for incidental, non-commercial purposes (e.g., swimming pools, garages, and workshops). This Schedule is not applicable to recognized boarding or rooming houses or commercial establishments. Energy taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $17.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1202/kWh

Non-Summer Season $0.1002/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and, 0.125 respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 6. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _______, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Residential General Service RG-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL
TIME-OF-USE RATE
SCHEDULE RT-16

Section 1. Availability:

Service hereunder is available, on a voluntary basis, as a pilot program, to residential customers in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. The availability of service under this rate schedule shall be limited to the first 300 customers requesting service during the pilot period.

Section 2. Applicability:

This Schedule is applicable to private residences, single family dwelling units, and farms. Energy delivered to each residence, dwelling unit, or farm shall be separately metered, and shall include energy used for incidental, non-commercial purposes (e.g., swimming pools, garages and workshops). This Schedule is not applicable to recognized boarding or rooming houses or commercial establishments. Energy taken under this Schedule may not be resold or shared with others.

"The Authority, at its sole option, may place under this Schedule RT-16 Customers having tankless electric water heaters or other types of loads that are estimated by the Authority to have an annual load factor less than 35%. If at the Authority's option a Customer is placed on this Schedule RT-16 and after twelve consecutive months of service the Customer's annual load factor is greater than or equal to 35%, then the Authority shall remove the Customer from the Schedule RT-16 and credit or debit the Customer's usage for the previous twelve month period for any difference in billing under the Schedule RT-16 and the then applicable residential schedule."

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of……………………………………………………...$26.00

(2) Energy Charge:

(a) Base Energy Charge:

All kWh during the Summer On-Peak Hours $0.3277/kWh

All kWh during the Non-Summer On-Peak Hours $0.2949/kWh

All kWh during Off-Peak Hours $0.0609/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of On-Peak and Off-Peak Hours:

Summer period On-Peak Hours shall mean the hours from 1:00 p.m. to 7:00 p.m., Monday through Friday, for the months of June, July, August, and September, excluding Memorial Day, Independence Day and Labor Day.

Non-Summer period On-Peak Hours shall mean the hours from 6:00 a.m. to 10:00 a.m., Monday through Friday, for the months of December, January, and February, excluding Christmas Day, and New Year Day.

Off-Peak Hours are defined as all hours not specified above as On-Peak hours.

Section 6. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 7. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect, which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule RT-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL TRANSITION ADJUSTMENT
SCHEDULE R-TA-16

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all residential users of energy and power as of April 1, 2016 receiving service pursuant to discontinued RN and RR Rate Schedules which included discounts for residences meeting certain energy efficiency standards. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Limitation of Service:

During the course of a comprehensive review of rates and charges, it was determined that approximately 11,000 active customers are taking service under Rate Schedules RN-13 & RR-13 which have been approved for termination. Beginning April 1, 2016, the Authority will systematically transition existing customers receiving service pursuant to RN-13 and RR-13 to the appropriate Residential General Service Rate Schedule.

The appropriate Residential General Service Rate Schedule will be Schedule RG-16 and its Successor Rate Schedules, or other then appropriate, applicable Residential Rate Schedules. To the extent a customer maintains active service during the transition period, the Transition Adjustment as described in Section 5, (A), (3), will apply. However, should a customer during the transition period terminate service, any new service at that premise shall have the option of the Residential General Service Schedule RG or the Residential Time-of-Use Rate Schedule RT.

The transition period shall consist of a three-year period commencing on April 1, 2016. Applicable credits will be reduced at a rate of 33.33% each year until this Transition Adjustment Schedule R-TA-16 is equal to the then-current Residential General Service Schedule RG.

Section 5. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $17.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1202/kWh

Non-Summer Season $0.1002/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and, 0.125 respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(3) Transition Adjustment:

The charges for Schedule R-TA-16 will be determined by applying the following credits to the charges described in Section 5, (A), (1) and 5, (A), (2).

	R1 Standard Plus		R2 Standard		R3 Standard Plus (Improved)		R4 Standard (Improved)	
	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)
Year 1	$ 8.00	$ 0.0042	$ -	$ 0.0042	$ 5.50	$ 0.0015	$ -	$ 0.0015
Year 2	$ 4.00	$ 0.0021	$ -	$ 0.0021	$ 2.75	$ 0.0008	$ -	$ 0.0008
Year 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 7. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _______, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Residential Good ₵ents RN-13 & RR-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE
SCHEDULE GA-16

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power having no more than a 50 kW potential demand in any three months of any twelve consecutive months, for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $21.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1125/kWh

Non-Summer Season $0.0925/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 6. Period of Contract:

The Contract Period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 7. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule GA-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE DEMAND
SCHEDULE GB-16

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge

For each month, a charge of $25.00

(2) Demand Charge:

All kW of Billing Demand $22.94/kW

(3) Energy Charges:

(a) Base Energy Charge:

Summer Season $0.0475/kWh

Non-Summer Season $0.0375/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to \$0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by \$0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge plus the Demand Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period or (ii) thirty percent (30%) of the greatest Measured Demand computed for the preceding eleven months.

Section 6. Payment:

All bills are due and payable at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill shall be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including late payment charges on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 7. Metering:

Power and energy shall be metered at the point of delivery by the Authority.

Section 8. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule GB-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
SEASONAL GENERAL SERVICE
SCHEDULE GV-16

Section 1. Availability:

This Schedule is available, on a voluntary basis, in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all commercial customers of the Authority meeting the eligibility requirements of the Authority's General Service Demand Rate Schedule, or its successor. Service hereunder applies to all service of the same voltage and character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage of the Authority, and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $25.00

(2) Demand Charge:

All kW of Billing Demand $24.60kW

(3) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.0475/kWh

Non-Summer Season $0.0375/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing

purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the Measured Demand for the current billing period.

Section 6. Payment:

All bills are due and payable at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill shall be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including, late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 7. Metering:

Power and energy shall be metered at the point of delivery by the Authority.

Section 8. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule GV-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE
TIME-OF-USE RATE
SCHEDULE GT-16

Section 1. Availability:

This Schedule is available on a voluntary basis in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability

This Schedule is applicable to all commercial customers of the Authority meeting the eligibility requirements of the Authority's General Service Schedules, or their successor. Service hereunder applies to all service of the same voltage and character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage of the Authority at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $30.00

(2) Demand Charges:

(a) All kW of On-Peak Billing Demand $25.23/kW

(b) All kW of Off-Peak Billing Demand $13.28/kW

(3) Energy Charges:

(a) Base Energy Charge:

All kWh during the Summer On-Peak Hours .... ….$0.0475/kWh

All kWh during the Non-Summer On-Peak Hours $0.0475/kWh

All kWh during Off-Peak Hours $0.0375/kWh

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge plus the Demand Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demands:

The Customer's On-Peak Measured Demand for each monthly billing period shall be the Customer's maximum 30-minute integrated kW demand occurring during the On-Peak Hours of such billing period, as recorded by or determined from suitable measuring devices; provided, however, that during any billing period when the average power factor is less than eighty-five percent (85%), the On-Peak Measured Demand will be adjusted by multiplying such On-Peak Measured Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent for such period.

The Customer's Off-Peak Measured Demand for each monthly billing period shall be the Customer's maximum 30-minute integrated kW demand occurring during the Off-Peak Hours of such billing period, as recorded by or determined from suitable measuring devices; provided, however that during any billing period when the average power factor is less than eighty-five percent (85%), the Off-Peak Measured Demand will be adjusted by multiplying such Off-Peak Measured Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent for such period.

(B) Billing Demands:

The Customer's On-Peak Billing Demand for each monthly billing period shall be the greater of (i) the On-Peak Measured Demand for such period, or (ii) thirty percent (30%) of the greatest On-Peak Measured Demand computed for the preceding eleven months.

The Customer's Off-Peak Billing Demand for each monthly billing period shall be the amount, if any, by which the Customer's Off-Peak Measured Demand for such period exceeds the On-Peak Billing Demand for such period.

Section 6. Determination of On-Peak and Off-Peak Hours:

(A) Summer period On-Peak Hours shall mean the hours from 1:00 p.m. to 7:00 p.m., Monday through Friday, for the months of June, July, August, and September, excluding Memorial Day, Independence Day and Labor Day.

(B) Non-Summer period On-Peak Hours shall mean the hours from 6:00 a.m. to 10:00 a.m., Monday through Friday, for the months of, January, February, March, April, May, October, November, and December, excluding Christmas Day and New Year Day.

(C) The Off-Peak Hours are defined as all hours not specified above as On-Peak Hours.

Section 7. Payment:

All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 8. Period of Contract

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule GT-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE GENERAL SERVICE
SCHEDULE GL-16

Section 1. Availability:

This Schedule is available on or near the transmission facilities of the Authority to customers in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2: Applicability:

This Schedule is applicable to all customers having more than 300 kW demand in at least three months of any twelve (12) consecutive months and having a rolling twelve month average load factor of at least 70 percent.

Section 3. Character of Service:

Power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed. Energy and power taken under this schedule may not be resold or shared with others.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $25.00

(2) Demand Charge:

Billing Demand

All kW of Billing Demand $23.29/kW

(3) Energy Charges:

(a) Base Energy Charge:

Summer Season $0.0465/kWh
Non-Summer Season $0.0365/kWh

Summer Season - The Summer Season energy charge shall apply to all kWh used during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season - The Non-Summer season energy charge shall apply to all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Credit:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge" plus the "Demand Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Transformation Discount

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the above Firm Demand Charge shall be reduced by $0.60/kW.

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

Section 6. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period, or (ii) thirty percent (30%) of the greatest Measured Demand computed for the preceding eleven months.

Section 7. Payment:

All bills are due and payable in good funds at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased by the larger of one hundred dollars ($100.00), or two percent (2%) of the amount then outstanding including late payment charges. on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 8. Metering

Power and energy shall be metered at the point of delivery by the Authority.

Section 9. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 10. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule GL-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TEMPORARY SERVICE
SCHEDULE TP-16

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to service of a temporary nature for all service of the same available character supplied to the Customer's premises through a single delivery point. For service of a temporary nature and after the initial 12 months of service, the Authority will review each temporary customer and, at its option, may elect to place the service on one of the Authority's other applicable schedules. Service will be provided only after application for service and execution of an agreement with the Authority covering costs of installation and termination of service. Energy taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase as available, at the nominal standard voltage of the Authority as available and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $21.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1406/kWh

Non-Summer Season $0.1206/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Installation and Termination Costs:

The Customer will be required to pay costs of installation and termination of service as calculated by the Authority, the payment for which will be set forth in an agreement executed by the Authority and the Customer. For temporary construction service all such payments shall be in advance, and in no event shall be less than $35.00 per connection.

(D) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payment in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including late charges on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 6. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer and shall be determined by the Authority.

Section 7. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted __________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule TP-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TRANSITION ADJUSTMENT
SCHEDULE TA-16

Section 1. Availability:

This Schedule is available, on a voluntary basis, in the retail service area of the Authority in Berkeley, Georgetown, (and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power as of December 1, 2013 receiving service pursuant to General Service Rate Schedule GA or Temporary Service Schedule TP, and who do not qualify for such service, for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Limitation of Service:

During the course of a review of customer billing records, it was determined that approximately 100 customers did not comply with the applicability requirements for Schedule GA-09 (General Service) or its successor schedules. Effective December 1, 2012, the Authority began systematically transitioning customers receiving service pursuant to GA-09, and who previously received or would have received power pursuant to GC-96, to the appropriate General Service Rate Schedule.

This transition adjustment rate schedule was also made available to ball park lighting customers who did not comply with the applicability requirements for Temporary Service Schedule TP-12 or its successor schedules. Effective February 1, 2014, the Authority began systematically transitioning ball park lighting customers receiving service pursuant to TP-12, or who received or would have received power pursuant to the Temporary Service and Ball Park Lighting Schedule TP-09 rate schedule, to the appropriate General Service Rate Schedule.

The appropriate General Service Rate Schedule will be Schedule GB-16 and its Successor Rate Schedules, or other then appropriate, applicable Rate Schedules. Representatives of the Authority will assist customers to select the appropriate and applicable rate schedule.

To the extent a customer selects to transition to General Service Rate Schedule GB-16 or its Successor Rate Schedules, the following transition adjustment will apply. However, should a customer during the transition period terminate service, no transition adjustment shall apply.

As a result of transitioning a customer to the proper rate schedule, customers selecting General Service Rate Schedule GB-16 will be billed commencing on the date upon which the customer receives service under the new rate schedule herein.

Section 5. Basic Monthly Charges:

For each month, at the amount set forth in the appropriate Schedule.

(1) Customer Charge:……………………………………………………………………….$25.00

(2) Summer Energy Charges:…………………………………………………………$0.0756/kWh
Non-Summer Energy Charges…………………………………………………$0.0656/kWh

All kWh at the amounts set forth in the appropriate Schedule.

(a) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to \$0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(3) Demand Charge:…………………………………………………………………$9.75/kW

All kW at the amount set forth in the appropriate Schedule.

(4) Transition Adjustment:

The non-summer energy charge for Schedule TA-16 will be determined by multiplying the energy charge in Schedule GB-16 or its Successor Rate Schedules by the following percentages in the appropriate year:

Apr.1			Adjustment
2016	Year	5	As Stated
2017	Year	6	160.00%
2018	Year	7	145.00%
2019	Year	8	130.00%
2020	Year	9	115.00%
2021	Year	10	100.00%

The summer energy charge for Schedule TA-16 will be determined by computing the difference between the summer and non-summer energy charge in Schedule GB-16 or its Successor Rate Schedules. This amount shall be added to the currently applicable TA-16

non-summer energy charge during the months specified in Schedule GB-16 or its Successor Rate Schedules.

The demand charge for Schedule TA-16 will be determined by multiplying the demand charge in Schedule GB-16 or its Successor Rate Schedules by the following percentages in the appropriate year:

Apr. 1			Adjustment
2016	Year	5	As Stated
2017	Year	6	54.00%
2018	Year	7	65.50%
2019	Year	8	77.00%
2020	Year	9	88.50%
2021	Year	10	100.00%

The ratios and charges set forth in this Transition Adjustment are subject to change if and when the Authority revises its rates and charges. All other provisions and Sections of the selected, applicable General Service Rate Schedule shall apply.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule TA-14, Effective February 1, 2014

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TRAFFIC SIGNAL SERVICE
SCHEDULE TL-16

Section 1. Availability:

This Schedule is available to all cities, towns, communities, and the State Highway Department located in the service area of the Authority.

Section 2. Applicability:

This Schedule is applicable for the operation of traffic signals located in the Authority's service area where the Authority has an existing secondary distribution line. Energy taken under this Schedule may not be resold or shared with other operations.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single-phase at 120 volts nominal.

Section 4. Installation:

The Authority will make its connection to the Customer's service wire on the Authority's nearest pole carrying 120/240 volt secondary. The Customer must furnish, install and maintain all service wires, fixtures and other equipment required for operation of the traffic signal installation.

Section 5. Monthly Billing Rate:

(A) Basic Monthly Charges:

(1) Metered Service:

(a) Customer Charge:

For each month, a charge of $21.00

(b) Base Energy Charge:

All kWh $0.1000/kWh

(5) Unmetered Service:

Base Energy Charge:

For each lamp using 25 watts or less .... $1.53 per lamp

For each lamp using 26 to 70 watts.......................................$2.17 per lamp

For each lamp using more than 70 watts .... $2.99 per lamp

(6) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to \$0.03641/kWh and 0.125, respectively.

(7) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(8) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge shall be the same as the monthly charges set forth herein above; provided, however, that if separate bills are required for each installation, the minimum bill shall be \$5.00 per installation.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payment in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Determination of Energy Usage for Unmetered Service:

For purposes of applying the aforementioned Fuel Adjustment Clause and Demand Sales Adjustment Clause, the monthly kWh usage for service provided hereunder shall be as follows:

For each lamp using 25 watts or less..5 kWh

For each lamp using 26 to 70 watts ....22 kWh

For each lamp using more than 70 watts...44 kWh

Section 7. Billing and Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents (\$0.50) or two percent (2%) of the amount then outstanding including late payment charges.

Section 8. Period of Contract:

The contract period shall be one (1) year or longer at the Authority's option.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule TL-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING
SCHEDULE MS-16

Section 1. Availability:

This Schedule is available to all cities, towns, communities, and the State Highway Department located in the service area of the Authority.

Section 2. Applicability:

This Schedule is applicable for municipal series and multiple circuit street, highway and bridge lighting within and immediately adjacent to city, town and community limits. Energy taken under this Schedule may not be resold or shared with other operations.

Section 3. Character of Service:

Energy delivered hereunder shall be alternating current, 60 Hertz, at a nominal standard voltage of the Authority, as available. Lamps may be connected in series or in multiple circuits, at the Authority's option.

Section 4. Installation:

The Authority will provide all labor and equipment necessary for installation including lamps and glassware. If the Authority is requested to provide a steel standard for the mounting of a light, the Customer will provide mixed concrete in the amount required for the standard. The Authority will provide the necessary forms and labor for the concrete work.

All equipment and other equipment installed by the Authority shall remain the property of the Authority.

Section 5. Monthly Rates and Charges:

The monthly charges hereunder shall consist of the following charges:

(A) Base Monthly Charges:

(1) Fixtures and Standards:

There shall be a monthly charge for each fixture and standard provided by the Authority, based on the type and characteristics thereof, determined in accordance with Exhibits A and B hereto, which such Exhibits A and B may be amended by the Authority from time to time to reflect the types of fixtures and standards the Authority will make available. In addition, the Authority may, at its sole option, provide on a work-order basis, fixtures and standards not provided for in Exhibits A and B if the Customer agrees to pay the Authority's cost of providing and installing such standards and fixtures.

(2) Energy Charges:

(a) Base Energy Charge:

All kWh $0.0639/kWh

(b) Fuel Adjustment Charge:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(d) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The monthly charge shall be the total of the charges specified hereinabove.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Determination of Energy Usage

To determine the Customer's energy usage at service connection, the Authority, at its option, may either (i) meter such energy usage, or (ii) estimate the monthly energy usage of such service based on the characteristics and mode of operation of the lamps and other equipment served therefrom.

Section 7. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges.

Section 8. Period of Contract:

The contract period shall be one (1) year or longer at the Authority's option.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule MS-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE MS-16

Exhibit A
Schedule of Available Poles and Arms

	Available Pole and Arm Type	Monthly Charge
1	Wood standard, 30'	$ 4.54
2	Wood, 35'	$ 5.20
3	Wood. 40'	$ 6.13
4	Fiberglass, Round, Black, 18'	$ 5.60
5	Fiberglass, Round, Brown, 20'	$ 5.78
6	Fiberglass, Round, 30'	$ 13.07
7	Fiberglass, Round, 40'	$ 13.17
8	Aluminum Standard, 25'	$ 11.98
9	Aluminum, Round, 35'	$ 20.70
10	Fiberglass, Round, 30' Breakaway DOT	$ 18.59
11	Light Pole, $301-$400	$ 10.07
12	Light Pole, $401-$500	$ 11.61
13	Light Pole, $501-$600	$ 13.09
14	Light Pole, $601-$700	$ 14.63
15	Light Pole, $701-$900	$ 16.88
16	Light Pole, $901-$1100	$ 19.88
17	Light Pole, $1101-$1300	$ 22.15
18	Light Pole, $1301-$1500	$ 24.41
19	Light Pole, $1501-$1700	$ 26.68
20	Light Pole, $1701-$1900	$ 28.90
21	Light Pole, $1901-$2100	$ 31.10
22	Light Pole, $2101-$2300	$ 33.30
23	Light Pole, $2301-$2500	$ 35.50
24	Light Pole Arm, $201-$400	$ 6.16
25	Light Pole Arm, $401-$600	$ 9.59
26	Light Pole Arm, $601-$800	$ 12.57
27	Light Pole Arm, $801-$1000	$ 15.40

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE MS-16

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
1	100 Watt, HPS, Private	41	$ 5.27
2	150 Watt, HPS, Private	61	$ 6.60
3	150 Watt, HPS, Traditional	61	$ 8.27
4	150 Watt, HPS, Roadway	61	$ 7.57
5	150 Watt, HPS, Modern (Shoebox)	61	$ 11.43
6	250 Watt, HPS, Roadway	103	$ 10.46
7	250 Watt, HPS, Shoebox	103	$ 14.54
8	400 Watt, HPS, Flood Light	164	$ 15.39
9	400 Watt, HPS, Roadway	164	$ 14.65
10	400 Watt, HPS, Shoebox	164	$ 18.95
11	400 Watt, MH, Flood Light	164	$ 16.37
12	400 Watt, MH, Galleria	164	$ 18.18
13	1000 Watt, MH, Flood Light	410	$ 32.93
14	1000 Watt, MH, Galleria	410	$ 35.07
15	$301-$400, 70 Watt, MH	29	$ 12.15
16	$301-$400, 175 Watt, MH	73	$ 14.96
17	$301-$400, 150 Watt, HPS	61	$ 14.20
18	$401-$500, 70 Watt MH	29	$ 13.55
19	$401-$500, 175 Watt MH	73	$ 16.36
20	$401-$500, 150 Watt HPS	61	$ 15.86
21	$401-$500, 250 Watt MH	103	$ 18.28
22	$401-$500, 250 Watt HPS	103	$ 18.54
23	$401-$500, 400 Watt MH	164	$ 22.17
24	$401-$500, 400 Watt HPS	164	$ 22.44
25	$401-$500, 1000 Watt MH	410	$ 37.88
26	$401-$500, 1000 Watt HPS	410	$ 38.15
27	$501-$600, 70 Watt MH	29	$ 14.95
28	$501-$600, 175 Watt MH	73	$ 17.76
29	$501-$600, 150 Watt HPS	61	$ 17.49
30	$501-$600, 250 Watt MH	103	$ 19.68
31	$501-$600, 250 Watt HPS	103	$ 20.17
32	$501-$600, 400 Watt MH	164	$ 23.57
33	$501-$600, 400 Watt HPS	164	$ 24.07
34	$501-$600, 1000 Watt MH	410	$ 39.28
35	$501-$600, 1000 Watt HPS	410	$ 39.78
36	$601-$700, 70 Watt MH	29	$ 16.35
37	$601-$700, 175 Watt MH	73	$ 19.16
38	$601-$700, 150 Watt HPS	61	$ 18.93
39	$601-$700, 250 Watt MH	103	$ 21.08

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
40	$601-$700, 250 Watt HPS	103	$ 21.62
41	$601-$700, 400 Watt MH	164	$ 24.97
42	$601-$700, 400 Watt HPS	164	$ 25.51
43	$601-$700, 1000 Watt MH	410	$ 40.68
44	$601-$700, 1000 Watt HPS	410	$ 41.22
45	$701-$800 175 Watt, MH	73	$ 20.56
46	$701-$800 150 Watt, HPS	61	$ 20.38
47	$701-$800 250 Watt, MH	103	$ 22.48
48	$701-$800 250 Watt, HPS	103	$ 23.06
49	$701-$800 400 Watt, MH	164	$ 26.37
50	$701-$800 400 Watt, HPS	164	$ 26.95
51	$701-$800 1000 Watt, MH	410	$ 42.08
52	$701-$800 1000 Watt, HPS	410	$ 42.66
53	$801-$900 175 Watt, MH	73	$ 21.96
54	$801-$900 150 Watt, HPS	61	$ 21.80
55	$801-$900 250 Watt, MH	103	$ 23.88
56	$801-$900 250 Watt, HPS	103	$ 24.48
57	$801-$900 400 Watt, MH	164	$ 27.77
58	$801-$900 400 Watt, HPS	164	$ 28.37
59	$801-$900 1000 Watt, MH	410	$ 43.48
60	$801-$900 1000 Watt, HPS	410	$ 44.08
61	$901-$1000 175 Watt, MH	73	$ 23.36
62	$901-$1000 150 Watt, HPS	61	$ 23.20
63	$901-$1000 250 Watt, MH	103	$ 25.28
64	$901-$1000 250 Watt, HPS	103	$ 25.88
65	$901-$1000 400 Watt, MH	164	$ 29.17
66	$901-$1000 400 Watt, HPS	164	$ 29.77
67	$901-$1000 1000 Watt, MH	410	$ 44.88
68	$901-$1000 1000 Watt, HPS	410	$ 45.48
69	Vandal Shield (1)	-	$ 1.90
	Experimental Fixtures (Energy Not Included in Monthly Rental Charge)		
70	$101-$300 Range, LED (3)	Varies by Fixture	*$ 6.18*
71	$301-$500 Range, LED (3)	Varies by Fixture	*$ 8.38*
72	$501-$700 Range, LED (3)	Varies by Fixture	*$ 10.58*
73	$701-$900 Range, LED (3)	Varies by Fixture	*$ 12.78*
74	$901-$1100 Range, LED (3)	Varies by Fixture	*$ 14.98*
75	$1101-$1300 Range, LED (3)	Varies by Fixture	*$ 17.18*
76	$1301-$1500 Range, LED (3)	Varies by Fixture	*$ 19.38*

Note 1: Vandal Shields may be required for fixtures receiving damage more than once during any consecutive three year period.

Note 2: All monthly rental charges include energy charges unless otherwise specified.

Note 3: Experimental fixtures do not include energy charges. Energy charges will vary based on specific fixture energy requirements and will be in addition to the stated rental charges.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-16

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable for outdoor yard and area lighting to retail customers where the Authority installs and furnishes the lighting equipment including lamps, fixtures, and the necessary lighting circuits and fittings. The monthly facilities and energy charges set forth in Section 4 are applicable only to lighting fixtures located so as to be furnished energy by existing facilities, poles and transformers on existing poles, or through the addition of not more than one (1) wood pole for attachment of each lighting fixture. Where extension of primary lines or special facilities or more than one (1) new pole per lighting fixture is required, the cost of constructing such additional facilities shall be repaid by the customer requesting service. Energy purchased under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

The Authority shall provide the outdoor yard and area lighting service hereunder including providing, installing, and maintaining the necessary facilities such as requisite poles and light fixtures on a contractual basis. Upon request for service, the Authority will require the execution of an agreement between the customer and the Authority (the "Outdoor Rental Lighting Agreement"). Energy delivered hereunder shall be alternating current 60 Hertz at the nominal standard voltage of the Authority, as available.

Section 4. Monthly Rates and Charges:

The monthly charges hereunder shall include the following charges:

(A) Basic Monthly Charges:

(1) Pole and Fixture Rental Fees:

There shall be a monthly charge for each pole and fixture furnished by the Authority, based on the type and characteristics thereof, determined in accordance with Exhibits A and B hereto. Such Exhibits A and B may be amended by the Authority from time to time to reflect the standard types of poles and fixtures the Authority will make available.

(2) Energy Charges:

(a) Base Energy Charge:

For each fixture, there shall be a base energy charge of $0.0639/kWh for all kWh of energy use.

(b) Fuel Adjustment Charge:

The Authority's Fuel Adjustment Clause FAC-16 is applicable to all energy sales hereunder, with "F/S" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-16 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Additional Facilities Charge:

The Basic Monthly Charges herein apply only to fixtures located so as to be furnished energy by existing facilities, poles and transformers on existing poles, and/or through the addition of not more than one pole for the attachment of each lighting fixture. Additional facilities, including the extension of primary lines, or special facilities, or more than one (1) new pole per lighting fixture, will be furnished by the Authority where the customer agrees to pay the cost of constructing such additional facilities.

(C) Minimum Charge:

The minimum charge shall be the same as the monthly charges set forth in Sections 4.A. and 4.B. hereinabove.

(D) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the customer has furnished the Authority evidence of specific exemption secured by the customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Energy Usage:

The Authority, at its option, may meter the monthly kWh energy usage of light fixtures provided hereunder. Otherwise, each unmetered fixture shall be deemed to use the estimated average monthly kWh energy set forth in the currently effective Exhibit B hereto.

Section 6. Payment:

(A) Bills for service hereunder shall become part of and shall be added to the customer's monthly account for metered electric service.

(B) Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. When the outdoor light is the only account with the Authority and payment of the bill is not received by said due date, the amount of the bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($0.50) or two percent (2%) of (i) the amount calculated under Section 4 of this Schedule or (ii) the total amount then outstanding including late payment charges. If the outdoor light is billed in conjunction with another account and payment of the bills is not received by said due date, then the total bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter by the larger of fifty cents ($0.50) or two percent (2%) of (i) the total amount calculated under this Schedule or (ii) the total bill then outstanding including late payment charges.

Section 7. Period of Contract:

The Outdoor Rental Lighting Agreement shall become effective on the date the lighting fixtures are first installed and operated and shall remain in effect for a period of three (3) years and thereafter until terminated by either party giving to the other thirty (30) days notice. In the event that the customer transfers, terminates or, for any reason, discontinues outdoor yard and area lighting service and/or electric service to the property on which the rental lighting is installed, the following charges shall become due and payable and may be paid in whole or in part by any deposit for electric service that the customer may have made:

> The greater of (i) the sum of the monthly charges for all remaining months of the effective terms of the Outdoor Rental Lighting Agreement, or (ii) fifty dollars ($50.00) for each fixture mounted on existing facilities, or (iii) one hundred fifty dollars ($150.00) for each fixture and pole that is caused to be removed due to termination of the Outdoor Rental Lighting Agreement.

In the event the customer wishes to terminate the private outdoor lighting service due to the sale, lease, or rental to others of the property on which lights are installed and the new party wishes to continue the rental agreement, the Authority shall release the customer from the termination charges provided for herein at such time that the new customer makes application for electric service and signs and Outdoor Rental Lighting Agreement for the remaining months of the original agreement.

Section 8. Limitations of Service:

(A) The Authority assumes the responsibility for ordinary maintenance of poles, equipment and lamps with all maintenance work to be performed during normal working hours at the discretion of the Authority.

(B) The Authority shall use reasonable diligence to provide a constant service to the lighting fixtures, but if such service or equipment shall fail or be interrupted, or become defective through acts of nature, or public enemies or by accident, strikes, labor troubles or by actions of the elements, or for any cause beyond its reasonable control, the Authority shall not be liable therefore.

(C) The Customer shall assume responsibility of providing reasonable protection to the lighting installation from accidental collision by motor vehicle and other similar equipment and shall further assume responsibility of providing the installation protection against vandalism.

(D) The Authority reserves the right to terminate private outdoor lighting service immediately upon the threat of damage or continued damage to the installed equipment.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect and the "Outdoor Rental Lighting Agreement" executed between the customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule OL-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-16

Exhibit A
Schedule of Available Poles and Arms

	Available Pole and Arm Type	Monthly Charge
1	Wood standard, 30'	$ 4.54
2	Wood, 35'	$ 5.20
3	Wood. 40'	$ 6.13
4	Fiberglass, Round, Black, 18'	$ 5.60
5	Fiberglass, Round, Brown, 20'	$ 5.78
6	Fiberglass, Round, 30'	$ 13.07
7	Fiberglass, Round, 40'	$ 13.17
8	Aluminum Standard, 25'	$ 11.98
9	Aluminum, Round, 35'	$ 20.70
10	Fiberglass, Round, 30' Breakaway DOT	$ 18.59
11	Light Pole, $301-$400	$ 10.07
12	Light Pole, $401-$500	$ 11.61
13	Light Pole, $501-$600	$ 13.09
14	Light Pole, $601-$700	$ 14.63
15	Light Pole, $701-$900	$ 16.88
16	Light Pole, $901-$1100	$ 19.88
17	Light Pole, $1101-$1300	$ 22.15
18	Light Pole, $1301-$1500	$ 24.41
19	Light Pole, $1501-$1700	$ 26.68
20	Light Pole, $1701-$1900	$ 28.90
21	Light Pole, $1901-$2100	$ 31.10
22	Light Pole, $2101-$2300	$ 33.30
23	Light Pole, $2301-$2500	$ 35.50
24	Light Pole Arm, $201-$400	$ 6.16
25	Light Pole Arm, $401-$600	$ 9.59
26	Light Pole Arm, $601-$800	$ 12.57
27	Light Pole Arm, $801-$1000	$ 15.40

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-16

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
1	100 Watt, HPS, Private	41	$ 5.27
2	150 Watt, HPS, Private	61	$ 6.60
3	150 Watt, HPS, Traditional	61	$ 8.27
4	150 Watt, HPS, Roadway	61	$ 7.57
5	150 Watt, HPS, Modern (Shoebox)	61	$ 11.43
6	250 Watt, HPS, Roadway	103	$ 10.46
7	250 Watt, HPS, Shoebox	103	$ 14.54
8	400 Watt, HPS, Flood Light	164	$ 15.39
9	400 Watt, HPS, Roadway	164	$ 14.65
10	400 Watt, HPS, Shoebox	164	$ 18.95
11	400 Watt, MH, Flood Light	164	$ 16.37
12	400 Watt, MH, Galleria	164	$ 18.18
13	1000 Watt, MH, Flood Light	410	$ 32.93
14	1000 Watt, MH, Galleria	410	$ 35.07
15	$301-$400, 70 Watt, MH	29	$ 12.15
16	$301-$400, 175 Watt, MH	73	$ 14.96
17	$301-$400, 150 Watt, HPS	61	$ 14.20
18	$401-$500, 70 Watt MH	29	$ 13.55
19	$401-$500, 175 Watt MH	73	$ 16.36
20	$401-$500, 150 Watt HPS	61	$ 15.86
21	$401-$500, 250 Watt MH	103	$ 18.28
22	$401-$500, 250 Watt HPS	103	$ 18.54
23	$401-$500, 400 Watt MH	164	$ 22.17
24	$401-$500, 400 Watt HPS	164	$ 22.44
25	$401-$500, 1000 Watt MH	410	$ 37.88
26	$401-$500, 1000 Watt HPS	410	$ 38.15
27	$501-$600, 70 Watt MH	29	$ 14.95
28	$501-$600, 175 Watt MH	73	$ 17.76
29	$501-$600, 150 Watt HPS	61	$ 17.49
30	$501-$600, 250 Watt MH	103	$ 19.68
31	$501-$600, 250 Watt HPS	103	$ 20.17
32	$501-$600, 400 Watt MH	164	$ 23.57
33	$501-$600, 400 Watt HPS	164	$ 24.07
34	$501-$600, 1000 Watt MH	410	$ 39.28
35	$501-$600, 1000 Watt HPS	410	$ 39.78
36	$601-$700, 70 Watt MH	29	$ 16.35
37	$601-$700, 175 Watt MH	73	$ 19.16
38	$601-$700, 150 Watt HPS	61	$ 18.93
39	$601-$700, 250 Watt MH	103	$ 21.08

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
40	$601-$700, 250 Watt HPS	103	$ 21.62
41	$601-$700, 400 Watt MH	164	$ 24.97
42	$601-$700, 400 Watt HPS	164	$ 25.51
43	$601-$700, 1000 Watt MH	410	$ 40.68
44	$601-$700, 1000 Watt HPS	410	$ 41.22
45	$701-$800 175 Watt, MH	73	$ 20.56
46	$701-$800 150 Watt, HPS	61	$ 20.38
47	$701-$800 250 Watt, MH	103	$ 22.48
48	$701-$800 250 Watt, HPS	103	$ 23.06
49	$701-$800 400 Watt, MH	164	$ 26.37
50	$701-$800 400 Watt, HPS	164	$ 26.95
51	$701-$800 1000 Watt, MH	410	$ 42.08
52	$701-$800 1000 Watt, HPS	410	$ 42.66
53	$801-$900 175 Watt, MH	73	$ 21.96
54	$801-$900 150 Watt, HPS	61	$ 21.80
55	$801-$900 250 Watt, MH	103	$ 23.88
56	$801-$900 250 Watt, HPS	103	$ 24.48
57	$801-$900 400 Watt, MH	164	$ 27.77
58	$801-$900 400 Watt, HPS	164	$ 28.37
59	$801-$900 1000 Watt, MH	410	$ 43.48
60	$801-$900 1000 Watt, HPS	410	$ 44.08
61	$901-$1000 175 Watt, MH	73	$ 23.36
62	$901-$1000 150 Watt, HPS	61	$ 23.20
63	$901-$1000 250 Watt, MH	103	$ 25.28
64	$901-$1000 250 Watt, HPS	103	$ 25.88
65	$901-$1000 400 Watt, MH	164	$ 29.17
66	$901-$1000 400 Watt, HPS	164	$ 29.77
67	$901-$1000 1000 Watt, MH	410	$ 44.88
68	$901-$1000 1000 Watt, HPS	410	$ 45.48
69	Vandal Shield (1)	-	$ 1.90
	Experimental Fixtures (Energy Not Included in Monthly Rental Charge)		
70	$101-$300 Range, LED (3)	Varies by Fixture	*$ 6.18*
71	$301-$500 Range, LED (3)	Varies by Fixture	*$ 8.38*
72	$501-$700 Range, LED (3)	Varies by Fixture	*$ 10.58*
73	$701-$900 Range, LED (3)	Varies by Fixture	*$ 12.78*
74	$901-$1100 Range, LED (3)	Varies by Fixture	*$ 14.98*
75	$1101-$1300 Range, LED (3)	Varies by Fixture	*$ 17.18*
76	$1301-$1500 Range, LED (3)	Varies by Fixture	*$ 19.38*

Note 1: Vandal Shields may be required for fixtures receiving damage more than once during any consecutive three year period.

Note 2: All monthly rental charges include energy charges unless otherwise specified.

Note 3: Experimental fixtures do not include energy charges. Energy charges will vary based on specific fixture energy requirements and will be in addition to the stated rental charges.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL LIGHT AND POWER
SCHEDULE ML-16

Section 1. Availability:

(A) Service hereunder is available at Delivery Points on or near the transmission facilities of the Authority to municipal, sales-for-resale customers having a contract demand of 1,000 kilowatts or more.

(B) This Rate Schedule is not available for breakdown, standby, supplementary, or auxiliary service, and service hereunder shall not be used in parallel with other sources of electric power.

(C) Prior to the provision of service hereunder at one or more Delivery Points, the Customer shall have entered into a Service Agreement, mutually agreeable to the Customer and the Authority, that shall set forth general terms and conditions of service hereunder.

Section 2. Character of Service:

(A) Electric power and energy delivered hereunder shall be unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, at one of the Authority's standard nominal voltages of 480 volts or higher. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed. Only one transformation will be provided hereunder from the available transmission voltage.

Section 3. Monthly Rates and Charges:

(A) Charges for Power Service:

(1) Monthly Customer Charge:

A monthly charge for each Delivery Point of $1,400.00

(2) Monthly Demand Charge:

(a) Base Demand Charge:

For the first 1,000kW or less of Billing Demand........................ $17,240.00

All Additional kW of Billing Demand $17.24

(b) Transformation Discount:

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the foregoing Base Monthly Demand Charge shall be reduced by $0.60/kW.

(c) Excess Demand Charge:

For each kW of the Customer's Measured Demand that is classified as Excess
Demand, a charge, in addition to the Base Demand Charge, of $11.00/kW.

(d) Demand Sales Adjustment:

For each kW of Billing Demand, a credit or change, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment DSC-16, or its currently applicable successor clause, if any.

(e) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any.

(3) <u>Energy Charge:</u>

(a) Base Energy Charge:

All kWh $0.0410/kWh

(b) Fuel Adjustment Clause:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-16, or its currently applicable successor clause, if any, with "Fb/Sb" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(1) <u>Excess Reactive Demand Charge:</u>

Each kVAr of Excess Reactive Demand $0.82/kVAr

(A) <u>Monthly Facilities Charges:</u>

In the event service to the Customer requires the Authority to provide facilities in addition to, or different from, facilities normally provided by the Authority, and the Authority provides such facilities, the Customer also shall pay the Authority a Monthly Facilities Charge, in addition to all other charges hereunder. Such Monthly Facilities Charge shall be equal to 1.4% of the original installed cost of such facilities.

(B) <u>Minimum Monthly Bill:</u>

The minimum monthly bill shall consist of the sum of the Monthly Customer Charge, the Monthly Demand Charge, and the Monthly Facilities Charge, if any.

(D) <u>Taxes and Other Assessments:</u>

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the foregoing monthly rates and charges. The total monthly billing amount hereunder also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Determination of Demands:

(A) Billing Demand:

(1) The Billing Demand for each Billing Month shall be the greater of (i) the Customer's Measured Demand for such Billing Month or (ii) eighty percent (80%) of the Contract Demand for such Billing Month.

(2) In the event that, during any Billing Month, the provision of service by the Authority hereunder is interrupted for a period of four (4) or more consecutive hours as a result of an occurrence of one of the circumstances set forth in Section 6(A) hereof, the Billing Demand for such Billing Month will be reduced by the proportion which the number of hours of such interruption bears to the total number of hours in the Billing Month.

(B) Measured Demand:

The Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the customer during such Billing Month; provided, however, that if the Customer's load is unbalanced between phases by more than ten percent (10%), the Authority, at its sole option, may (i) require the Customer, at the Customer's expense, to make the changes necessary to correct such condition, and/or (ii) assume that the load on each phase is equal to the greatest load on any phase.

(C) Contract Demand:

(1) Except as otherwise provided herein, the Contract Demand applicable to each Delivery Point during each Billing Month shall be the maximum amount of power, in kilowatts, that the Customer shall have requested and the Authority shall have agreed to supply during such Billing Month, as evidenced in the Service Agreement between the Customer and the Authority. During the first twelve (12) months of service to a new Delivery Point, the Authority, at its sole option, may agree to adjust the Customer's Contract Demand on a month-to-month basis and/or to forego the application of Section 4 (D) hereinbelow, in order to allow the Customer and the Authority an adequate build-up or phase-in of operations; provided, however, that the Authority reserves the right to condition such agreement on such additional terms and conditions as the Authority deems appropriate for the circumstances.

(2) Except as otherwise provided herein or in the Service Agreement between the Customer and the Authority, the Customer may reduce its Contract demand for a Delivery Point, or any twelve month period and subsequent twelve month periods, to not less than 1,000 kW by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first Period to which the notice applies, provided, however, that (i) no such reduction shall become effective before the fifth anniversary of service to the Delivery point, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Contract Demand(s) for such years.

Notices of such reductions in the Customer's Contract Demand shall be irrevocable once given.

(3) The Customer's Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rate Schedule, or (ii) by mutual agreement between the Authority and the Customer. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request by the Customer. In such an event, the Authority may require additional, special terms and conditions applicable to service to the Customer.

(D) Excess Demand:

(1) The Customer's Excess Demand for each Billing Month shall be that portion of the Customer's Measured Demand for such Billing Month that exceeds 110% of the Customer's then current Contract Demand hereunder.

(2) Notwithstanding the foregoing or any other provision of this Rate Schedule to the contrary, in the event that (i) the Customer's rate or use of electricity at a Delivery Point exceeds the Customer's then current Contract Demand hereunder, and (ii) the Customer fails to comply promptly with a request by the Authority to reduce such rate of use so as not to exceed such aggregate Contract Demand, the Customer's Contract Demand(s) for such Delivery Point for the current and subsequent Billing Months, shall at the Authority's sole option, be increased, from what it otherwise would have been, by the amount of such excess. In addition, in such event, the Customer shall be liable for any damage to the Authority's facilities caused by such excess.

(3) Notwithstanding the foregoing or any other provision of this Rate Schedule, the Authority shall be under no obligation whatsoever to supply demands in excess of the Customer's Contract Demand, and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed the Customer's Contract Demand.

(E) Excess Reactive Demand:

The Customer's Excess Reactive Demand for each Billing Month shall be the amount, if any, by which the Customer's maximum 30-minute integrated reactive demand, in kilovars (kVAr) during such Billing Month exceeds 48.5% of the Customer's Measured Demand, in kilowatts (kW), for such Billing Month.

Section 5. Billing:

All bills are due and payable at the offices of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased by the greater of (i) one hundred dollars ($100.00), or (ii) two percent (2%) of the amount then outstanding including late payment charges. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of the service shall not relieve the Customer of any liability for the Agreed Minimum Bill(s) for the period(s) of time service is so discontinued.

Section 6. Interruption of Service:

(A) The Authority will make reasonable provisions to ensure satisfactory and continuous service but does not guarantee a continuous supply of electrical energy and shall not be liable for damage occasioned by interruptions of service or failure to commence delivery caused by an act of God, or the public enemy, or for any cause reasonably beyond the Authority's control, including, but not limited to, the failure or breakdown of generating or transmitting facilities, floods, fire, strikes or action or order of any agency having jurisdiction over the premises, or for interruptions that the Authority deems necessary for the inspection of, repair to, or changes to the Authority's facilities.

(B) Nothing herein shall be construed as restricting in any way the Authority's right to interrupt service to the Customer as the Authority may deem necessary or appropriate to facilitate inspection of, repair to, or changes to the Authority's facilities consistent with prudent utility practice; provided, however, that the Authority shall use its reasonable best efforts, when practicable, to provide the Customer with advance notice of such interruptions and to coordinate with the Customer the times of such interruptions. In any event, failure of the Authority and the Customer to agree upon the time of such an interruption shall not restrict the Authority from proceeding therewith as the Authority deems necessary.

(C) The Customer shall provide written notification to the authority immediately of any defects, trouble or accident which may in any way affect the delivery of power by the Authority to the Customer.

(D) Notwithstanding any provisions of this Rate Schedule to the contrary, the Customer shall not be liable for any charges hereunder for any period during which he is unable to accept electric service due to strikes, fire, floods, or act of God or the public enemy.

(E) Both the Customer and the Authority shall use all due diligence in removing any causes which prevent the delivery or use of electrical power and energy hereunder.

(F) Any claims against the Authority resulting from an interruption of service shall be governed by the terms, conditions and limitations of the South Carolina Tort Claims Act, and any recovery in such claim shall not include indirect or consequential damages.

Section 7. Indemnity:

All electrical power and energy provided for hereunder shall be the property of the Customer upon passing the Delivery Point(s) and the Customer shall have sole responsibility for the use, misuse or presence of said power and energy on the Customer's side of the Delivery Point(s). The Customer will indemnify and hold the Authority harmless from al claims, loss or expense arising from, or in any way connected with, the presence, use of misuse of electrical power and energy on the Customer's side of the Delivery Point(s).

Section 8. Additional Terms and Conditions:

Service under this Rate Schedule is subject to the then currently effective Service Agreement between the Customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for service rendered on or after April 1, 2016

Supersedes:
Schedule ML-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
SCHEDULE L-16

Section 1. Availability:

(A) Service hereunder is available at Delivery Points on or near the transmission facilities of the Authority at which the Customer has a potential demand for electric service of at least 1,000 kW; provided, however, that service hereunder shall not be available for service to large, highly fluctuating or otherwise unusual loads without the agreement of the Authority.

(B) Subject to the terms of this Rate Schedule and the General Terms and Conditions of Large Power Electric Service (hereinafter, "General Terms and Conditions") attached hereto as Attachment A and made a part hereof, service hereunder is available, at individual Delivery Points each satisfying the requirements of the foregoing paragraph, to (i) industrial, commercial, and governmental Customers of the Authority, and (ii) municipal and cooperative wholesale Customers of the Authority may offer this service to an industrial, commercial, or governmental customer of such wholesale customer.

(C) Except as may be otherwise provided in the Standby Service Rider L-16-SB, this Rate Schedule is not available for breakdown, standby, supplementary, or auxiliary service, and service hereunder shall not be used in parallel with other sources of electric power. Except with respect to service to municipal and cooperative Customers of the Authority, as provided in the foregoing paragraph, service hereunder shall not be sold for resale or exchange or shared with others.

(D) Prior to the provision of service hereunder at one or more Delivery Points, the Customer shall be required to enter into an Agreement for Large Power Electric Service (hereinafter, "Service Agreement") of the form prescribed in the General Terms and Conditions which may be modified by the Authority from time to time.

Section 2. Character of Service:

(A) Electric power and energy delivered hereunder shall be unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, at one of the Authority's standard nominal voltages of 480 volts or higher. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed. Only one transformation will be provided hereunder from the available transmission voltage.

(B) "Firm Power," as used herein, shall refer to electric power and energy purchased by the Customer hereunder, other than electric power and energy purchased by the Customer pursuant to any other applicable rider or riders hereto.

Section 3. Monthly Rates and Charges:

(A) Monthly Customer Charge:

A monthly charge for each Delivery Point of $3,400.00

(B) Charges for Standard Firm Power Service:

The monthly charges for Firm Power hereunder shall include the following charges:

(1) Monthly Demand Charge:

(a) Base Demand Charge:

For the first 300 kW or less of Firm Billing Demand $7,332.00

All Additional kW of Firm Billing Demand @ $18.80

(c) Transformation Discount:

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the foregoing Base Monthly Demand Charge shall be reduced by $0.60/kW.

(d) Excess Demand Charge:

(i) For each kW of the Customer's Measured Demand that is classified as Excess On-Peak Demand, a charge, in addition to the Base Demand Charge, of $11.00/kW.

(ii) For each kW of the Customer's Measured Demand that is classified as Excess Off-Peak Demand, a charge equal to the Base Demand Charge.

(e) Excess Reactive Demand Charge:

Each kVAr of Excess Reactive Demand @ $0.82/kVAr

(f) Demand Sales Adjustment:

For each kW of Firm Billing Demand, a credit or charge, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment Clause DSC-16, or its currently applicable successor clause, if any.

(g) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-16), or its currently applicable successor clause, if any.

(2) Energy Charge:

(a) Base Energy Charge:

On-Peak kWh @ $0.0575/kWh

Off-Peak kWh @ $0.0375/kWh

(b) ....
For all energy taken during the month and classified under the Off-Peak Demand provision, an Off-Peak Energy Premium of $0.0183/kWh shall apply. Such charge shall be in addition to the Off-Peak Base Energy Charges above.

(c) Fuel Adjustment Charge:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-16, or its currently applicable successor clause, if any, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.09, respectively.

(C) Charges Under Applicable Riders:

The monthly charges hereunder shall include the charges for services provided the Customer under any and all applicable riders hereto.

(D) Monthly Facilities Charges:

In the event service to the Customer requires the Authority to provide facilities in addition to, or different from, facilities normally provided by the Authority, and the Authority provides such facilities, the Customer also shall pay the Authority a Monthly Facilities Charge, in addition to all other charges hereunder. Such Monthly Facilities Charge shall be equal to 1.4% of the original installed cost of such facilities.

(E) Minimum Monthly Bill:

The minimum monthly bill shall consist of the sum of (i) the Monthly Customer Charge, (ii) the Monthly Facilities Charge, if any, (iii) the Monthly Demand Charge for Firm Power Service, and (iv) the minimum monthly charges, if any, determined pursuant to any applicable rider or riders under which the Customer also receives service from the Authority.

(F) Taxes and Other Assessments:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the foregoing monthly rates and charges. The total monthly billing amount hereunder also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Determination of Demands:

(A) Firm Billing Demand:

(1) The Firm Billing Demand for each Billing Month shall be greater of (i) On-Peak Measured Demand, or (ii) eighty percent (80%) of the Firm Contract Demand, but no greater than one hundred (100%) of Firm Contract Demand for such Billing Month. If the Customer receives Firm Power only, then the Customer's Firm Billing Demand shall not be less than 1,000 kW.

(2) In the event that, during any Billing Month, the provision of service by the Authority hereunder is interrupted for a period of four (4) or more consecutive hours as a result of an occurrence of one of the circumstances set forth in Section 9(A) of the General Terms and Conditions, the Firm Billing Demand for such Billing Month will be reduced by the proportion which the number of hours of such interruption bears to the total number of hours in the Billing Month.

(3) The Customer's Off-Peak Demand Provision shall refer to the amount, if any, by which (a) the lesser of (i) Off-Peak Measured Demand during that Billing Month or (ii) the Customer's then current Off-Peak Maximum demand exceeds (b) the sum of the Firm Contract Demand hereunder plus the Customer's Contract Demands (if any) under any and all riders hereto and other rate schedules of the Authority, plus the Customer's Excess Firm On-Peak Demand (if any) during that billing month. The Customer's Off-Peak Maximum Demand shall be established at the request of the Customer and modified by the Authority from time to time in recognition of the limitations of the delivery facilities serving the Customer and other limiting considerations on the Authority's system however, in no event shall requested demand exceed 20 percent (20%) of the sum of the Customer's Firm and Interruptible Contract Demand(s). Unless and until the authority shall have agreed in writing to a specific Off-Peak Maximum Demand, it shall be deemed to be equal to the sum of the Firm Contract Demand hereunder plus the Customer's Contract Demand(s) (if any) under any and all riders hereto and other rate schedules of the Authority, exclusive of Nominated of curtailed capacity as provided under L-16-DRB. All energy served under the Off-Peak Demand Provision shall incur charges as described in Section 3(B)(2)(b).

(4) Firm Billing Demand, and the Off-Peak Demand Provision, as described and calculated herein, shall be exclusive of Nominated or curtailed capacity as provided under L-16-DRB, including provisions for Customer's Contract Demand(s) in Section 4 (A) (1) and Section 4 (A) (3) above.

(B) Measured Demand:

(1) Subject to the applicable provisions, if any, of any rider or riders hereto pursuant to which the Customer also receives service, the Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the customer during such Billing Month.

(2) The On-Peak Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the Customer that shall have occurred during the Billing Month during On-Peak Demand Hours. As used herein, On-Peak Demand Hours shall refer to the same as stated in Section 5(A).

(3) The Off-Peak Measured Demand shall be the maximum 30-minute integrated kW demand of the Customer that shall have occurred in the Billing Month at a time other than during On-Peak Demand Hours.

(4) In determining each of the Customer's Measured Demand, On-Peak Measured Demand, and Off-Peak Measured Demand, whenever the Customer's load is unbalanced between phases by more than ten percent (10%), the load on each phase shall be deemed to be equal to the greatest load on any phase. Furthermore, whenever the Customer's load frequently is found to be unbalanced between phases by more than ten percent (10%), the Authority, at its sole option, may require the Customer, at the Customer's expense, to make the changes necessary to correct such condition.

(C) Firm Contract Demand:

(1) Except as otherwise provided herein, the Firm Contract Demand applicable to each Delivery Point during each Billing Month shall be the maximum amount of Firm Power, in kilowatts, that the Customer shall have requested and the Authority shall have agreed to supply during such Billing Month, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and made a part of, the Service Agreement between the Customer and the Authority. During the first twelve (12) months of service to a new Delivery Point, the Authority, at its sole option, may agree to adjust the Customer's Firm Contract Demand on a month-to-month basis and/or to forego the application of the Section 4 (D) here in below, in order to allow the Customer and the Authority an adequate build-up or phase-in of operations; provided, however, that the Authority reserves the right to condition such agreement on such additional terms and conditions as the Authority deems appropriate for the circumstances.

(2) Except as otherwise provided herein or in the General Terms and Conditions, the Customer may reduce its Firm Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month period(s), to not less than 300 kW by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of service to the Delivery Point, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Firm Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Firm Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Firm Contract Demand for such year.

(d) For the fourth and subsequent twelve month period(s), the maximum reduction shall be 100% of the respective Firm Contract Demand(s) for such years.

Notices of such reductions in the Customer's Firm Contract Demand shall be irrevocable once given.

(3) The Customer's Firm Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rate Schedule or applicable rider(s) hereto under which the Customer also receives service, or (ii) by mutual agreement between the Authority and the Customer

evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional, special terms and conditions applicable to service to the Customer to be included in the aforementioned new Delivery Point Specification Sheet.

(4) Notwithstanding any other provisions hereof, in no event shall the Customer's Firm Contract Demand be less than the amount, if any, by which the sum of the Customer's then current contract demands under all applicable riders hereto is less than 1,000 kW.

(D) Excess Demand:

(1) The Customer's Excess On-Peak Billed Demand for each Billing Month shall be the greater of (a) that portion of the Customer's On-Peak Measured Demand for such Billing Month, if any, that exceeds the sum of (i) the Customer's then current Firm and Interruptible Billed Demand hereunder, and, where applicable, (ii) the Customers' Contract Demand(s), if any, under any and all applicable rider or riders to which the Customer also receives service from the Authority, exclusive of L-13-DRB or its successor.

(2) The Customer’s Excess Off-Peak Demand for each Billing Month shall be that portion of the Customer's Off-Peak Measured Demand for such Billing Month, if any, that exceeds the sum of the Customer's then-current Off-Peak Maximum Demand and the Excess On-Peak Billed Demand above.

(3) Notwithstanding the foregoing or any other provision of this Rate Schedule or the General Terms and Conditions to the contrary, in the event that, at any time, (i) the Customer's rate of use of electricity at a Delivery Point exceeds the Customer’s Maximum Demand applicable at that time, and (ii) the Customer fails to comply promptly with a request by the Authority to reduce such rate of use so as not to exceed such Maximum Demand, the Customer's Firm Contract Demand(s) for such Delivery Point for the current and subsequent Billing Months, shall at the Authority's sole option, be increased, from what it otherwise would have been, by the amount of such excess. In addition, in such event, the Customer shall be liable for any damage to the Authority's facilities caused by such excess. The Customer’s Maximum Demand during Peak Demand Hours shall be equal to the sum of (i) the Customer's then current Firm Contract Demand hereunder and, where applicable, (ii) the Customer's then current Contract Demand(s), if any, under applicable riders hereto. The Customer’s Maximum Demand in hours other than Peak Demand Hours shall be equal to the Customer’s then current Off-Peak Maximum Demand.

(4) Notwithstanding the foregoing or any other provision of this Rate Schedule or the General Terms and Conditions, the Authority shall be under no obligation whatsoever to supply demands in excess of the Customer's aggregate Contract Demand(s), and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed the Customer's aggregate Contract Demands.

(E) Excess Reactive Demand:

The Customer's Excess Reactive Demand for each Billing Month shall be the amount, if any, by which the Customer's maximum 30-minute integrated reactive demand, in kilovars (kVAr), during such Billing Month exceeds 48.5% of the Customer's Measured Demand, in kilowatts (kW), for such Billing Month.

Section 5. Determination of On-Peak and Off-Peak Hours:

(A) Demand

(1) On-Peak Demand Hours

i. Summer On-Peak Demand Hours shall mean the hours from 1:00 p.m. to 10:00 p.m., Monday through Friday, for the months of May, June, July, August, and September.

ii. Non-Summer On-Peak Demand Hours shall mean the hours from 5:00 a.m. to 9:00 a.m. and from 6:00 p.m. to 10:00 p.m., Monday through Friday, for all other months.

(2) Off-Peak Demand Hours

i. The Off-Peak Demand Hours are defined as all hours not specified above as On-Peak Demand Hours. The Authority may call for additional Off-Peak Demand Hours from time to time based on operational limitations or cost constraints. Additional Off-Peak Demand hours shall be designated at the sole discretion of the Authority.

(B) Energy

(1) .... On-Peak kWh are defined as all kWh consumed by the customer during the calendar months of June, July and August between the hours of 1PM and 10PM during weekdays (prevailing time).

(2) .... Off-Peak kWh are defined as all kWh consumed by the customer during all other hours of the year.

Section 6. Additional Terms and Conditions:

Service under this Rate Schedule, including service under all applicable riders hereto, is subject to the then currently effective General Terms and Conditions and the Service Agreement between the Customer and the Authority.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
Schedule L-14, Effective February 1, 2014

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)

General Terms and Conditions
of
Large Power Electric Service

Section 1. Contract For Service

(A) As a condition precedent to the Authority supplying electric service under the Authority's Large Light and Power Rate Schedule L-16 and/or any and all riders thereto (collectively, "Schedule L"), to which these General Terms and Conditions are attached and made a part of, the Customer shall execute a Service Agreement in the form hereinafter provided as Exhibit I hereto. When executed by the Customer and the Authority, such Service Agreement, together with Schedule L, these General Terms and Conditions, and applicable notices of Contract Demands accepted by the Authority, shall constitute the entire contract for service between the Authority and the Customer.

(B) In the event of any conflict between these General Terms and Conditions and the provisions of the Service Agreement or Schedule L, the provisions of the Service Agreement or Schedule L shall govern.

(C) Nothing contained in any and all parts of Schedule L, the Service Agreement, and these General Terms and Conditions, shall be construed as affecting in any way the right of the Authority to make changes to any and all parts of such documents as provided by law.

(D) A separate Delivery Point Specification Sheet, in the form hereinafter provided as Exhibit II hereto, shall be prepared and executed by the Authority and the Customer for each Delivery Point at which the Customer is to receive service. Each such Delivery Point Specification Sheet, shall be deemed to be attached to, and made a part of, the Service Agreement between the Customer and the Authority.

(E) As used herein, "Delivery Point" refers to the point or points at which the electrical conductors (including bus bars) of the Authority are connected to the electrical conductors of the Customer or, in the case of service hereunder to a municipal or cooperative wholesale Customer of the Authority, to the conductors of that Customer or a retail customer of wholesale Customer. The Authority shall normally provide one three-phase service at a single voltage at each Delivery Point. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed.

Section 2. Conditions of Service

(A) The Authority's agreement to provide electric service on the date specified for electric service to each Delivery Point, subject to proper written notice as set forth in the applicable Rate Schedule, is contingent upon the Authority's ability to acquire, at a sufficient time prior to the date for commencement of such service, the necessary State and Federal approvals and the necessary rights of way and equipment for providing such electric service.

(B) With respect to facilities installed by the Authority to provide electric service to the Customer, the Authority reserves the right to use any available capacity of such facilities not needed for such service to supply other customers of the Authority.

Section 3. Electric Service Provided

(A) The Authority will provide electric service to Customer in the form of unregulated, three-phase alternating current at a frequency of approximately 60 Hertz.

(B) The Authority will provide electric service pursuant to the provisions of Schedule L at the nominal voltage desired by Customer provided such voltage is generally available in the area in which the electric service is desired. For Delivery Points existing on the date these General Terms and Conditions become effective, the nominal voltage supplied shall be the Authority's present nominal delivery voltage at such Delivery Points.

(C) The Authority will provide electric service for each Delivery Point at the nominal voltage specified in the Exhibit II to the Service Agreement for the Delivery Point, unless the Authority notifies the Customer in writing that the voltage will be changed to a specified higher or lower voltage in accordance with usual utility practices. In such cases, the Customer at the Customer's own expense will design, engineer, install, construct or modify, operate, and maintain facilities to such higher or lower voltage.

Section 4. Monthly Billing and Payment

(A) The Authority shall render to the Customer, after the end of each Billing Month, a bill setting forth the charges, as specified in Schedule L, for such Billing Month. "Billing Month" refers to a period between successive meter readings, which shall normally be once per month.

(B) All bills shall be on a net basis, and each such bill shall be due and payable in good funds at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of one hundred dollars ($100.00), or two percent (2%) of the amount then outstanding including late payment charges. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of the service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 5. Metering and Measurement

(A) Power and energy shall be metered by the Authority at, or as if at, each Delivery Point.

(B) Not less frequently than once each year, the Authority shall make periodic tests and inspections of meters installed by it. At the request of the Customer, the Authority shall make additional tests or inspections. Readings of metering instruments found to be in error by more than two percent (2%) either fast or slow will be corrected and credits or debits made to the Customer's account accordingly. Such correction shall apply for a period of not more than thirty (30) days prior to the date of test unless a longer period of inaccuracy can be definitely determined. The Customer shall pay all costs resulting from additional tests requested by the Customer if tests show meters to be accurate within two percent (2%).

Section 6. Use of Service

(A) Power shall be used in such manner as will not cause objectionable voltage fluctuations or other electrical disturbances on the Authority's system. If such fluctuations and disturbances become objectionable, the Authority may require the Customer, at the Customer's own expense, to install appropriate corrective equipment.

(B) The Service Agreement shall not be assigned by the Customer without approval in writing by the Authority. Service hereunder is exclusively for use by the Customer, and is not to be resold or shared with others. In consideration of the terms of the Service Agreement and these General Terms and Conditions, and in recognition of the fact that the supplying of power and energy from more than one source to the Customer's Facilities may adversely affect safety and the Authority's operations, the Customer agrees not to accept electrical service for said plant operations from any source other than the Authority during the terms of the Service Agreement.

Section 7. New Delivery Points

(A) To establish a new Delivery Point, the Customer must execute with the Authority a new Delivery Point Specification Sheet for the new Delivery Point prior to the date upon which the new Delivery Point is to be placed in service. Such new Delivery Point Specification Sheet shall be attached to, and made a part of, the Service Agreement and shall include any special provisions required for the establishment of the new Delivery Point. The execution of such Delivery Point Specification Sheet shall be a condition precedent to the Authority's supplying electric service to the Delivery Point.

(B) The Authority shall not be obligated to establish any new Delivery Point if it is reasonably determined by the Authority that, consistent with Prudent Utility Practice, the new Delivery Point is not necessary or appropriate for the delivery of power to serve load on the Customer's system.

(C) The Authority shall not be obligated to establish any new Delivery Point if after exercising due diligence the Authority cannot obtain all necessary State and Federal approvals, rights-of-way, and equipment. The Customer shall support all State and Federal filings that the Authority deems necessary (i) for supplying capacity and energy to the new Delivery Point, (ii) for the construction and permitting of the new Delivery Point, and (iii) such other facilities as the Authority deems necessary for the new Delivery Point.

(D) The Customer or potential Customer requesting the establishment of a new Delivery Point shall submit a detailed written request to the Authority specifying the requirements of such Delivery Point.

(E) Except as otherwise provided herein, the Customer is responsible for the installation, operation and maintenance of all necessary poles, lines, substations, transformers, switches, protective equipment, and other equipment (except the Authority's metering equipment) necessary for the establishment of a new Delivery Point, and for all facility rearrangements on the Customer's side of such Delivery Point that are required for the establishment thereof.

(F) Substantial and/or material modifications to an existing Delivery Point shall be deemed to constitute the termination of such Delivery Point and the establishment of a new Delivery Point.

Section 8. Delivery Points and Other Facilities

(A) The service specifications for each Delivery Point shall be as prescribed in the corresponding Delivery Point Specification Sheet.

(B) For each Delivery Point, the Customer shall provide, free of cost to the Authority, a suitable site on the premises for the installation by the Authority of equipment for rendering service hereunder. The Customer shall also provide for the safekeeping of this equipment and shall not permit anyone other than authorized employees and agents of the Customer and employees and agents of the Authority to have access thereto.

(C) The Customer hereby grants to the Authority for the entire term of this contract, free of cost, the right to construct, operate and maintain on property owned, leased or controlled by the Customer, all poles, conductors, appurtenances and equipment whatsoever reasonably necessary or desirable for supplying service hereunder to each Delivery Point. The Authority shall also have all rights of access to said property reasonably necessary or desirable for the aforesaid purposes and the right to remove all or any portion of the Authority's property at any time during the term of this contract or within a reasonable time thereafter. All property, structures and facilities erected by the Authority on property of the Customer are recognized and agreed by the parties to be removable trade fixtures, which shall be and remain personal property of the Authority whether affixed to the realty or not.

(D) Employees of the Authority shall be allowed access to the service installation site at all reasonable hours for the purpose of reading the metering instruments, inspecting the property of the Authority, removing such property, and for other purposes incident to the supplying of service to the Customer.

(E) All electrical facilities used or constructed by the Customer must conform to accepted modern practice and to applicable state and local requirements and must conform to the requirements of the National Electrical Safety Code and National Electrical Code.

(F) All facilities on the Customer's side of each Delivery Point shall be considered the system of the Customer, shall be paid for by the Customer, and shall be installed, operated, and maintained by the Customer at the Customer's expense; provided, that (i) the Authority's metering equipment, if any, located on the Customer's side of a Delivery Point will be owned, installed, operated, and maintained by the Authority; and (ii) the Authority shall have the right, at the Authority's option, to install and/or maintain such other facilities on Customer's side of a Delivery Point as the Authority may elect in the interests of system reliability.

(G) The Customer shall not utilize, or allow to be utilized, any equipment, appliance, or device that tends to unreasonably adversely affect the system of the Authority. The Customer shall maintain a reasonable electrical balance between the phases at each Delivery Point.

(H) The Customer shall install and maintain suitable protective devices on the Customer's system in order to afford reasonably adequate protection to the facilities of the Authority against adverse conditions or disturbances originating on Customer's system. Such protective devices shall be in accordance with the applicable industry standards relating to such equipment and with such other requirements as the Authority may reasonably deem necessary.

(I) The Authority shall install, own, operate, and maintain all lines and equipment located on the Authority's side of each Delivery Point, as well as the meter and metering equipment and, if applicable, any backup meter and metering equipment that may, at the Authority's option, be located on Customer's side of each Delivery Point. In such cases, Customer shall provide a location, acceptable to the Authority, for the installation of such metering equipment.

(J) In the event that the Customer requests the Authority to supply electricity in a manner requiring facilities in addition to or different from those normally provided by the Authority, the Authority will provide such facilities on the Authority's side of the Delivery Point, if practical to do so, provided the following conditions are met and a new Delivery Point Specification Sheet for such Delivery Point is executed to reflect these conditions:

1) The Customer requesting the facilities shall submit a detailed written request to the Authority specifying the type and kind of facilities;

2) The facilities are of a kind and type used by, or acceptable to, the Authority and are, installed in a place and in a manner acceptable to the Authority; and

3) The Customer agrees, in the Delivery Point Specification Sheet for the subject Delivery Point, to pay to the Authority the cost of the facilities prior to their installation or, at the Authority's sole option, appropriate Monthly Facilities Charges in lieu thereof, in addition to the other charges recoverable under Schedule L.

4) Meters and metering related equipment will be sized according to On-Peak Contract Demand, as specified by customer. Costs associated with metering and metering related equipment required to appropriately measure demand in excess of On-Peak Contract Demand will be the responsibility of the Customer. The Authority, as its sole option, may collect costs associated with meters and metering equipment, or upgrades associated therewith, within the appropriate Monthly Facilities Charge.

(K) In the event that the Customer's contract demand(s) under Schedule L (including any applicable riders thereto) is (are) reduced, nothing herein shall be construed as restricting the right of the Authority to change or reduce accordingly the capacity of the Authority's facilities serving the Customer.

(L) The Delivery Point Specification Sheet for each Delivery Point shall set forth appropriate provisions concerning the installation and maintenance of the Delivery Point and shall provide for adequate compensation to the Authority on termination of the Delivery Point by the Customer.

Section 9. Interruption of Service

(A) The Authority will make reasonable provisions to ensure satisfactory and continuous service but does not guarantee a continuous supply of electrical energy and shall not be liable for damage occasioned by interruptions of service or failure to commence delivery caused by an act of God, or the public enemy, or for any cause reasonably beyond the Authority's control, including, but not limited to, the failure or breakdown of generating or transmitting facilities, floods, fire, strikes or action or order of any agency having jurisdiction over the premises, or for interruptions that the Authority deems necessary for the inspection of, repair to, or changes to the Authority's facilities.

(B) Nothing herein shall be construed as restricting in any way the Authority's right to interrupt service to the Customer as the Authority may deem necessary or appropriate to facilitate inspection of, repair to, or changes to the Authority's facilities consistent with Prudent Utility Practice; provided, however, that the Authority shall use its reasonable best efforts, when practicable, to provide the Customer with advance notice of such interruptions and to coordinate with the Customer the times of such interruptions. In any event, failure of the Authority and the Customer to agree upon the time of such an interruption shall not restrict the Authority from proceeding therewith as the Authority deems necessary.

(C) The Customer shall provide written notification to the Authority immediately of any defects, trouble or accident which may in any way affect the delivery of power by the Authority to the Customer.

(D) Notwithstanding any provisions of Schedule L to the contrary, the Customer shall not be liable for any charges under this Schedule for any period during which he is unable to accept electric service due to strikes, fire, floods, or act of God or the public enemy.

(E) Both the Customer and the Authority shall use all due diligence in removing any causes which prevent the delivery or use of electrical power and energy hereunder.

(F) Any claims against the Authority resulting from an interruption of service shall be governed by the terms, conditions and limitations of the South Carolina Tort Claims Act, and any recovery in such claim shall not include indirect or consequential damages.

Section 10. Indemnity

All electrical power and energy provided for hereunder shall be the property of the Customer upon passing the Delivery Point(s) and the Customer shall have sole responsibility for the use, misuse or presence of said power and energy on the Customer's side of the Delivery Point(s). The Customer will indemnify and hold the Authority harmless from all claims, loss or expense arising from, or in any way connected with, the presence, use or misuse of electrical power and energy on the Customer's side of the Delivery Point(s).

Section 11. Determination of Contract Demands

The maximum amount, or amounts, of electric power and energy that the Authority agrees to sell, and that the Customer agrees to purchase at each Delivery Point (the Customer's "Contract Demand(s)") initially shall be set forth in the Delivery Point Specification Sheet for such Delivery Point. The initial establishment of, and subsequent changes to, such Contract Demand(s) shall be made only pursuant to the applicable provisions of Schedule L; provided, however, that the Authority reserves the right to require, for any Customer or potential Customer having a load of greater than 100,000 kW, notice requirements for changes in that Customer's Contract Demands(s) longer than those set forth in Schedule L.

Section 12. Term of Contract

(A) The Service Agreement, terminating on its effective date all prior agreements between the parties, shall become effective on the date specified therein, and shall remain in effect for an initial term of five (5) years, and thereafter for additional terms of two (2) years such, unless terminated by written notice of such intention from either party to the other at least one (1) year prior to the expiration date of the initial term or subsequent term; provided, however, that in no event shall the Service Agreement expire prior to (i) the expiration of the initial term as outlined above, or (ii) the reduction of the Customer's Contract Demand(s) to zero in the manner or manners specified in Schedule L. Nothing herein contained shall in any way bar the right of the Authority to collect any sums due it at the termination of the prior agreements.

If the Customer discontinues operations prior to the expiration of the initial term of the Service Agreement, or any subsequent term, or defaults under this Service Agreement in any respect and the Authority terminates the Service Agreement as a result of such default, the Customer agrees to pay to the Authority, on demand, a sum equal to the cumulative total of the Minimum Monthly Bills, as determined under Schedule L, for the remainder of the term of the Service Agreement, or any subsequent term.

(B) "Contract Year" shall be a twelve-month period beginning on the earlier of (i) the anniversary of the date service is initiated or (ii) the anniversary of the effective date of the Service Agreement.

(C) Schedule L and these General Terms and Conditions may be amended or revised by the Authority from time to time, in whole or in part, to reflect changed conditions, and when so amended or revised shall become effective as to all customers receiving service hereunder.

Section 13. Waiver

Any failure at any time by the Authority or the Customer to enforce a provision of Schedule L, these General Terms and Conditions, or the Service Agreement, shall not constitute a waiver by such party of said provision.

Section 14. Other Contracts

(A) Notwithstanding any other provision of Schedule L or these General Terms and Conditions to the contrary, an existing contract between the Authority and a Customer for the provision of service to such Customer pursuant to the Authority's Large Light and Power Rate Schedule that is in effect on the effective date of these General Terms and Conditions shall continue in full force and effect until its expiration. Such existing contract shall be deemed to constitute the Service Agreement between the Customer and the Authority hereunder until its expiration. In the event any provision of these General Terms and Conditions or Schedule L conflicts with a provision of such existing contract, the provision of the contract shall prevail.

(B) Upon the expiration of an existing contract between a Customer and the Authority, as described in the foregoing paragraph, continued service to such Customer shall be wholly subject to Schedule L and these Terms and Conditions.

(C) The establishment of a new Delivery Point, or the substantial modification of an existing Delivery Point, for a Customer having an existing contract, as described in the foregoing two paragraphs, shall require the termination of such existing contract and the execution of a new Service Agreement of the form specified in Exhibit I hereto.

(D) The terms and conditions of service to a Customer at a Delivery Point or Delivery Points under any rate schedule(s) or contract(s) other than Schedule L shall be unaffected by the terms of Schedule L and these General Terms and Conditions and shall be governed solely by the terms of such other rate schedule(s) or contract(s). The terms and conditions and service to each Delivery Point pursuant to Schedule L shall be governed solely by the provisions of Schedule L and these General Terms and Conditions and shall be unaffected by service, if any, to a Delivery Point or Delivery Points under any other rate schedule(s) or contract(s) between the Customer and the Authority.

(E) Acceptance of service under Schedule L without the benefit of an executed Service Agreement or another formal, written contract between the Customer and the Authority will bind the Customer to all terms and conditions of Schedule L and these General Terms and Conditions the same as if a formal written contract had been executed. In such event, all obligations hereunder shall begin on the date of such acceptance of service and shall continue for an initial term of five (5) years and thereafter for additional terms of two (2) years each, unless and until terminated at the end of such initial term or any additional term by no less than one (1) year's advance written notice of termination from either party to the other.

Adopted _____________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule L-14, Attachment A, Effective February 1, 2014

Exhibit I

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
SERVICE AGREEMENT FOR LARGE POWER ELECTRIC SERVICE

This Agreement made and entered in this ______ day of ________________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and _________________________, hereinafter referred to as the "Customer."

W I T N E S S E T H:

That in consideration of the mutual covenants and agreements herein contained, the Authority and the Customer covenant and agree with each other as follows:

1. The Authority shall sell and deliver to the Customer, and the Customer shall purchase and receive from the Authority, the Customer's full requirements for electric service at the Delivery Point(s) specified in the respective Delivery Point Specification Sheets attached to this Service Agreement. Each such Delivery Point Specification Sheet shall, upon its execution, be a part of this Service Agreement, and shall include the service specifications for the provision of service at the corresponding Delivery Point.

2. A change in the service specifications at a Delivery Point shall require a new Delivery Point Specification Sheet to be executed to replace the previous Delivery Point Specification Sheet for that Delivery Point.

3. This Service Agreement adopts and incorporates by reference all of the provisions of the Authority's Large Light and Power Rate Schedule L-16 and all riders thereto (collectively, "Schedule L"), and its associated General Terms and Conditions, as such Schedule L and General Terms and Conditions may be changed from time to time.

4. The Customer shall pay the Authority monthly for electric service rendered hereunder pursuant to the applicable Rate Schedule and in accordance with the billing and payment provisions of Schedule L and the General Terms and Conditions.

5. This Service Agreement may not be assigned by either Party without the prior written consent of the other Party, provided, however, such consent shall not be unreasonably withheld.

6. If any provision of this Service Agreement is inconsistent with any provision of any applicable rate schedule or associated riders, the provisions of this Service Agreement shall prevail.

7. Subject to the provisions hereinbefore contained, this contract shall be binding upon and inure to the benefit of the successors and assigns of the parties hereto.

IN WITNESS WHEREOF, the Authority and the Customer have caused this Service Agreement for the Large Power Electric Service to be executed in duplicate in their names by their respective duly authorized officials, as of the day and year first above written.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ___________________________	**BY:** ___________________________
ATTEST:	_________________________________ **(CUSTOMER)**
BY: ___________________________	**BY:** ___________________________

Exhibit II

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
SERVICE AGREEMENT FOR LARGE POWER ELECTRIC SERVICE
DELIVERY POINT SPECIFICATION SHEET

1. Electric Service Supplied to:

2. Delivery Point Information:

   (a) Name:
   (b) Description:
   (c) Location:

3. Original Effective Date of Delivery Point:

4. Effective Date of this Specification Sheet:

5. Contract Demand(s):

   (a) Firm Power Contract Demand:
   (b) Interruptible Power Contract Demand:
   (c) Economy Power Contract Demand:
   (d) Standby Power Contract Demand
   (e) Demand Response Buy Back Demand

6. Electric Service Supplied: ____ volts (nominal) ____ Phase

7. Metering Data:

   (a) Metered Voltage:
   (b) Location:
   (c) Compensation:

8. Provisions for Special Facilities or Conditions:

IN WITNESS WHEREOF, the Authority and the Customer have each caused this Delivery Point Specification Sheet, which is to be incorporated into the Service Agreement for Large Power Electric Service, dated ____________, to be executed in their names by their respective duly authorized officials on this ___ day of __________, 20__.

ATTEST: | **SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**

BY: ____________________________ | **BY:** ____________________________

ATTEST: | ________________________________ **(CUSTOMER)**

BY: ____________________________ | **BY:** ____________________________

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
INTERRUPTIBLE SERVICE
RIDER L-16-I

Section 1. Availability:

(A) Service hereunder, "Interruptible Power", is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-16 or its successor (hereinafter, "Schedule L"), to which this Rider L-16-I is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-16-I, the sum of the Customer's Contract Demands under this Rider L-16-I plus the Customer's Firm Contract Demand must equal or exceed 1,000 kW.

(C) The total amount of Interruptible Power available to all customers changes from time to time and the availability of such power hereunder is strictly subject to the provisions of this Rider L-16-I, including, without limitation, Section 4 (B)(4) herein below. As of January 1, 2012, the Authority has determined that Interruptible Power service will be made available to existing customers under contract and additional qualifying customers on a “first come first served” basis up to a maximum aggregate amount based on the Authority’s reserve requirement.

Section 2. Character of Service:

(A) Interruptible Power hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L that (i) is in excess of Firm Power purchased by the Customer under Schedule L and (ii) is interruptible or curtailable by the Authority in accordance with the following terms of this Rider.

(B) Curtailments by the Authority

(1) The Authority shall have the right, at any time or times and for any reason or reasons, to interrupt or call for curtailment of all or part of the Interruptible Power in response to an Emergency Event. As used herein, an “Emergency Event” means a condition on the Authority’s system in which, in the sole judgment of the Authority’s System Controller, action is required to maintain compliance with approved Reliability Standards or there is an imminent danger of deterioration of service to firm customers, voltage collapse, or damage to a part of the system.

(2) The Authority shall have the right, at any time or times and for any reason or reasons, to interrupt of call for curtailment of all or part of the Interruptible power in response to market or system conditions, hereinafter “Economic Curtailments”, not deemed Emergency Events. Such Economic Curtailments shall not exceed 250 hours, nor occur in more than 60 days, in any calendar year and, provided further, the number of such Economic Curtailments shall not exceed two (2) in any calendar day or 72 hours in any calendar week (Monday through Sunday.) Electrical power and energy purchased by the Customer pursuant to this section shall be classified as "Secondary Power."

(a) During the months of January, February, and December, the Authority reserves the right to curtail custumers for not longer than 48 consecutive hours. The Authority shall use good faith efforts to alert the Customer of such curtailment with at minimum 12 hours notification. With each such notification, the Authority shall supply the Customer with a quotation of the energy prices, in cents per kilowatt hour, applicable to power taken during the hours to which the notification applies. Curtailment hours shall be considered used when called.

(b) At any time or times, except as provided in Section 2(B)(2)(c) below, the Authority reserves the right to curtail customers for not longer than twelve (12) aggregate hours in any calendar day. Such curtailments shall occur independently from curtailments described in Section 2(B)(2)(a) above and such curtailments may occur during the same clock hour. In the event that the Authority deems it necessary and prudent to call for curtailment during the same clock hour for which another curtailment has been called, all provisions of the previous curtailment for the clock hour, including quoted prices and scheduled usage, shall be considered null and void.

(c) In the event that the Authority designates Economic Curtailments for greater than 24 continuous clock hours, the 12 hours immediately following the termination of the Economic Curtailment period shall be considered exempt from Economic Curtailments. Such limitation shall in no way restrict the duration of a single continuous Economic Curtailment period.

(d) In order to receive Secondary Power at a Delivery Point during an hour, the Customer shall respond to the Authority's notification for curtailment within a period of time to be established by the Authority, following such notice. Such responses shall include the maximum 30-minute integrated kW demand the Customer requests and is willing to receive during each period of time, hereinafter the interval, determined by the Authority, subject to its availability. The Authority, at it's option, may respond to and confirm agreement to the Customer's request or may not respond further, in which event such confirmation and agreement shall be deemed to have been given.

(e) As used herein, "Scheduled Secondary Demand" shall, for any hour, be the maximum 30-minute integrated kW scheduled for delivery to the Customer during such hour pursuant to this Rider L-16-I. "Delivered Secondary Demand", shall be the maximum 30-minute integrated kW demand by which the metered deliveries of power and energy to the Customer during the interval exceed theCustomer's then-current Firm Contract Demand under Schedule L.

(3) The Authority shall establish and maintain operational guidelines which shall state the conditions and circumstances under which calls for curtailments may be made. Such operational guidelines shall be published, and available for review, at the Authority's offices.

(4) When the Authority wishes to interrupt or curtail the Customer's Interruptible Power as provided herein, the Authority shall give notice thereof to the Customer by telephone or by such other means as the Authority may from time to time designate. Each such notice shall specify a demand level, which may be zero, to which the Customer's use of Interruptible Power is to be limited and the time period (hereinafter, a "Curtailment Period") to which such limitation is to apply. After receiving such a notice, the Customer shall, except as otherwise provided herein, limit the Customer's use of Interruptible Power during the Curtailment Period to which the notice applies, to the level specified by the Authority. Each such notice shall be deemed received by the Customer if the Authority shall have issued or attempted to issue that notice.

(5) The Authority will use reasonable efforts to give as much advance notice as practicable of probable curtailments when circumstances permit. The final scheduling of Emergency Event curtailments by the Authority will be postponed as long as practicable in order to minimize their occurrence and duration. Each notice issued by the Authority may be withdrawn or modified prior to the beginning of the potential Curtailment Period to which it applies. Such withdrawal or modifications shall be issued to the Customer by the same means as the original notices. Notices, if and to the extent so modified, shall be deemed to establish final Curtailment Periods and demand limitations. Notices withdrawn prior to the beginning of their respective Curtailment Period shall be without any further force or effect. The Authority shall confirm final notices of curtailment by subsequent letter to the Customer as soon as reasonably practicable after the end of the respective Curtailment Periods.

(6) After a notice of curtailment shall have been issued by the Authority, the Customer shall have the right to exceed the demand limitation set forth in the notice if, and only if, (i) the Customer makes a request to do so pursuant to the timetable established for the Curtailment Period to which the notice applies and the Authority, in its sole judgment, determines that it can supply the requested excess, and (ii) the Customer agrees to pay for such excess at the price(s) quoted by the Authority in response to such request. The Authority shall designate in writing from time to time a representative to whom such requests should be directed, and the Customer shall designate in writing from time to time a representative of the Customer who is authorized to make such requests and issue such agreements. Requests that are granted and the corresponding agreements to pay the quoted prices shall be confirmed in writing by the Authority as soon as is reasonably practicable after the corresponding Curtailment Periods have ended.

(7) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period that is not classified as Secondary Power shall be classified as Excess Power; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Power.

Section 3. Monthly Rates and Charges:

For all Interruptible Power provided hereunder, the monthly charge shall consist of the following charges:

(A) Interruptible Power:

For all services provided hereunder other than Secondary Power and Excess Power:

(1) Monthly Demand Charge:

(a) All kW of Interruptible Billing Demand @ $10.18/kW

(b) For each kW of Interruptible Billing Demand, a charge or credit, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment Clause DSC-16, or its currently applicable successor clause, if any.

(c) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-12), or its currently applicable successor clause, if any.

(2) Monthly Energy Charge:

(a) Base Energy Charge:

On-Peak kWh @ $0.0575/kWh
Off-Peak kWh @ $0.0375/kWh

(b) Fuel Adjustment Charge:

For each kWh, the charge or credit per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-16, or its successor clause, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(B) Secondary Power:

(1) The price for Secondary Power used by the Customer in each Curtailment Period shall be the price quoted by the Authority for such power and energy as hereinabove described. Each such quotation shall be based on the Authority's reasonable best estimate of its incremental costs of supplying such Secondary Power, plus a margin of 15% above the Authority's incremental costs.

(2) Scheduling

a. Overscheduling charges shall equal the amount, if any, by which the Customer's Delivered Secondary Demand for the hour was less than 80 percent (80%) of the Customer's Scheduled Secondary Demand for the interval, times 15% of the quoted energy price for the interval times the number of clock hours in the interval. Charges shall not apply to Delivered Secondary Demand within 100 kW of the Customer's Scheduled Secondary Demand for that interval.

b. Underscheduling charges shall equal the amount, if any, by which the Customer's Delivered Secondary Demand for each Economic Curtailment interval exceeds the Customer's Scheduled Secondary Demand for the interval, times 150% of the quoted price for the interval times the number of clock hours in the interval.

c. During a single continuous Economic Curtailment and in lieu of Underscheduling and Overscheduling charges listed in hereinbefore, the total Overscheduling and Underscheduling charges may be levied on the net difference between Delivered Secondary Demand and Scheduled Secondary Demand each interval during the curtailment. Applicable charges for this demand shall be levied at the average quoted price for energy taken during the curtailment period and the average number of interval hours. Such charges shall be at the sole discretion of the Authority.

(C) Excess Power:

The price for Excess Power used by the Customer in each Emergency Event Curtailment Interruption Period as defined in Section 2(B)(1) shall be 150% of the Authority's reasonable best estimate of its incremental cost (including opportunity costs) of supplying such Excess Power. Such incremental costs may include both demand-related and energy-related costs.

In addition, whenever the Customer shall have used Excess Power during an Emergency Event Curtailment Period as defined in Section 2(B)(1), the provisions of Section 4(C) below shall apply.

Section 4. Determination of Demands:

(A) Interruptible Billing Demand

The Customer's Interruptible Billing Demand for each Billing Month shall be the amount, if any, by which the Customer's Measured On-Peak Demand for such month, determined pursuant to Section 4(B) of Schedule L, exceeds the Customer's then-current Firm Billed Demand, under Schedule L, however, that in no event shall such Interruptible Billing Demand be (i) greater than 100% of the interruptible contract demand or (ii) less than 80 percent (80%) of the sum of the Customer's then-current Firm and Interruptible Contract Demand less Firm Billed Demand.

As used in Section 4(A) only, Firm Billed Demand shall include an adjustment for energy billed under Section 3(B)(2)(b) of Schedule L. Such adjustment shall be calculated monthly utilizing the following formula:

*Off-Peak Demand = (Off-Peak Energy / Off-Peak Hours) * 1.5*

where Off-Peak Energy means all energy billed under Section 3(B)(2)(B) of Schdule L and Off-Peak Hours means the total number of Off-Peak demand hours for the month under Section 5(A)(2) of Schedule L.

(B) Interruptible Contract Demand

(1) Except as otherwise provided herein, the Customer's Interruptible Contract Demand shall be the maximum amount of Interruptible Power, in kilowatts, that the Customer has requested and the Authority has agreed to supply, as evidenced in the Delivery Point Specification Sheet for which the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer may reduce its Interruptible Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month periods, by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of the Service Agreement between the Customer and the Authority, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Interruptible Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Interruptible Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Interruptible Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Interruptible Contract Demand(s) for such years.

Notices of such reductions in the Customer's Interruptible Contract Demand shall be irrevocable once given.

(3) The Customer's Interruptible Contract Demand, once established or reduced, may be increased only by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(4) The total amount of Interruptible Power available for sale to all customers changes from time to time. In initially determining the amount of Interruptible Power, if any, to provide a Customer

and/or in determining the amount, if any, by which a Customer's Interruptible Contract Demand may be increased, the Authority shall take into account the total amount of such Interruptible Power it reasonably expects to be available and its prior commitments for sales of such power. If, and to the extent that, the Authority thus determines it can make additional Interruptible Power available to new Customers and to existing Customers, the Authority shall do so on a first-come, first-served basis, in accordance with the stated limit of Interruptible Power specified in Section 1 (C) herein.

(C) Excess Demands

(1) In the event the Customer's use of service during any Emergency Event Curtailment Period exceeds the demand level established by the Authority for such Curtailment Period, the Customer's Interruptible Contract Demand shall be reduced, and the Customer's Firm Contract Demand shall be increased, by the greatest 30-minute integrated demand of such excess. In such event, such reduction and such increase each shall apply for the current Billing Month and the subsequent eleven (11) Billing Months.

(2) Notwithstanding the foregoing or any other provision of this Rider L-16-I, Schedule L, or the General Terms and Conditions attached thereto, the Authority shall be under no obligation whatsoever to supply demands in excess of the demand level established by the Authority during a Curtailment Period, and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed such demand level.

Section 5. Other Terms and Conditions:

Service under this Rider L-16-I, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Adopted ____________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule L-13-I, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
ECONOMY POWER SERVICE
RIDER L-16-EP

Section 1. Availability and Applicability

(A) Service hereunder, "Economy Power," shall be available to customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-16 or its successor (hereinafter, "Schedule L"), to which this Rider L-16-EP is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-16-EP, the sum of the Customer's Contract Demands under this Rider L-16-EP plus the sum of the Customer's Firm Contract Demand and Interruptible Contract Demand must equal or exceed 2,000 kW.

Section 2. Character of Service

(A) Economy Power hereunder shall consist of the supply of electric power and energy, of the same general characteristics as described in Schedule L, that the Authority may from time to time, in its sole discretion, determine to be available from the Authority's resources (including the Authority's arrangements with other utilities) in excess of the power and energy requirements of the Authority's other customers.

(B) The Authority shall use good faith efforts to notify the Customer of the availability of Economy Power in each clock hour prior to the beginning of such hour through a means established by the Authority from time to time. With each such notification, the Authority also shall supply the Customer with a quotation of the Economy Energy Price, in cents per kilowatt hour, applicable to Economy Power during the hour to which the notification applies.

(C) In order to receive Economy Power at a Delivery Point during an hour, the Customer shall respond to the Authority's notification for such hour within a period of time, to be established by the Authority, following such notice. Such response shall include the amount of Economy Power the Customer requests and is willing to receive in the applicable hour, subject to its availability. The Authority, at its option, may respond to confirm agreement to the Customer's request or may not respond further, in which event such confirmation and agreement shall be deemed to have been given.

(D) The Authority shall use its reasonable best efforts, but shall be under no obligation whatsoever, to provide periodic estimates of the expected availability and price of Economy Power for upcoming hours and upcoming days. However, such estimates shall be estimates for preliminary planning purposes only, shall be subject to change without notice, and shall have no force or effect. To facilitate the Authority's planning and the aforementioned estimates, the Customer, at the request of the Authority, shall promptly provide the Authority with the Customer's best reasonable estimate of the Customer's requirements for Economy Power in upcoming hours and days. However, such estimates shall be for preliminary planning purposes only, shall be subject to change without notice, and shall have no force or effect.

(E) As used herein, "Scheduled Economy Energy" shall, for any hour, be the amount, if any, of Economy Power scheduled for delivery to the Customer during such hour pursuant to this Rider L-16-EP. "Delivered Economy Energy", for any hour or half-hour, shall be the amount, if any, by which the metered deliveries of power and energy to the Customer in such hour or half-hour exceed the sum of (i) the Customer's then-current Firm Contract Demand under Schedule L, and (ii) the Customer's then current Interruptible Contract Demand, if any, pursuant to Rider L-13-I, but in no event greater than the Customer's then current Economy Power Contract Demand hereunder.

(F) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period identified in Section 4 (B)(2) shall be classified as Excess Economy Power; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Economy Power.

Section 3. Monthly Rates and Charges

Charges to the Customer for Economy Power hereunder shall be equal to the sum of (i) the Monthly Customer Charge, (ii) the Monthly Reservation Charge, (iii) the Monthly Energy Charge, and (iv) the Monthly Excess Economy Power Demand Charge, all as set forth below:

(A) Monthly Customer Charge

The Monthly Customer Charge hereunder shall be $1,000.00 per month for each Billing Month.

(B) Monthly Reservation Charge

The Monthly Reservation Charge hereunder shall be equal to the Customer's Economy Power Contract Demand for such Billing Month, in kilowatts, times $1.77 per kilowatt.

(C) Monthly Energy Charge

The Monthly Energy Charge hereunder shall be the aggregate sum of all applicable Hourly Energy Charges during the Billing Month. Each such Hourly Energy Charge shall be the sum of (1), (2), and (3) below for such hour:

(1) The amount, if any, of Delivered Economy Energy up to the amount of Scheduled Economy Energy for the hour times the Economy Energy Price for that hour;

(2) Overscheduling charges shall equal the amount, if any, by which the Customer's Delivered Economy Energy for the hour was less than 90% of the Customer's Scheduled Economy Energy for the hour, times the Capital Improvement Fund and generation-related charges in the Economy Energy Price as stated in Section 3(C)(3) below; and

(3) Underscheduling charges shall equal he amount, if any, by which the Customer's Delivered Economy Energy for the hour exceeded the Customer's Scheduled Economy Energy for the hour, times 150% of the Economy Energy Price for the hour. In the event that the Authority determines the Economy Energy Price for the hour does not sufficiently recover the costs to serve such excess power, the Authority reserves the right to charge 150% of the Authority's best reasonable estimate of the actual incremental cost to serve. Such decision shall be at the sole discretion of the Authority.

In addition, whenever the Customer shall have used Excess Economy Power during a Curtailment Period, the provisions of Section 4 (B) below shall apply.

For each hour, the aforementioned Economy Energy Price applicable to Economy Power hereunder shall be the price quoted by the Authority for the hour pursuant to Section 2 hereof. For each hour, such Economy Energy Price shall be the greater of (i) the Authority's Incremental Energy Cost, plus markups to include contributions to the Capital Improvement Fund, transmission losses, and generation-related expenses, or (ii) the price at which the Authority could have sold such Economy Power to another utility or utilities, based on actual quotes from such other utility or utilities. Such Incremental Energy Cost shall be the Authority's best reasonable estimate of its out-of-pocket, incremental cost of producing Economy Power during such hour, as determined in accordance with usual utility practice. In no event shall the final Economy Energy Price quoted by the Authority for an hour be subject to after-the-fact adjustment except as allowed in this.
For the purposes of the L-16-EP Economy Energy Price, contributions to generation-related expenses shall equal $7.96/MWH.

For the purposes of the L-16-EP Economy Energy Price, contributions to the Capital Improvement Fund and transmission losses shall equal the Authority's Incremental Energy Cost times a factor of 0.1299. Such charges may be modified from time-to-time.

(D) Monthly Excess Economy Power Demand Charge

The Monthly Excess Economy Power Demand Charge hereunder shall be equal to (i) the greatest 30-minute integrated kW demand of Excess Economy Power, multiplied by (ii) six (6) times the sum of the per-kW rates for the Firm Base Demand Charge and the Excess Demand Charge specified in Schedule L.

(E) Optional Charge(s)

From time to time, at its sole discretion, the Authority may elect to offer customers served under this Rider pricing alternatives. The Optional Charge(s) hereunder shall be set forth along with the terms and conditions of each alternative in writing. The Customer, at its sole discretion, shall have the choice of receiving any portion of Economy Energy under the Optional Charge(s).

Section 4. Determination of Demands

(A) Economy Power Contract Demand

(1) The Customer's Economy Power Contract Demand for each Delivery Point shall be established initially by mutual agreement of the Authority and the Customer, as evidenced in the Delivery Point

Specification Sheet for the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer's Economy Power Contract Demand may be unilaterally reduced by the Customer, in whole or in part, such reduction to become effective at the beginning of a Billing Month specified by the Customer if, and only if, the Customer shall have provided the Authority with at least twenty-four (24) months prior written notice of such reduction. Notices of such reductions in the Customer's Economy Power Contract Demand shall be irrevocable once given.

(3) The Customer's Economy Power Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rider L-16-EP, or (ii) by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require that additional, special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(B) Excess Demands

(1) The amount of Economy Power requested by the Customer in an hour shall be subject to pro rata reduction in the event the Authority determines, in its sole judgement, the aggregate amount of Economy Power so requested by the Customer and all other such customers exceeds the total amount available for such hour. In such event, the Authority shall so notify the Customer prior to the beginning of such hour, and the prorated amount requested by the Customer shall be deemed to supersede the Customer's prior request and shall be deemed to constitute the agreed-upon amount of Economy Power for delivery to the Customer's Delivery Point for that hour, unless the Customer, prior to the beginning of the hour, withdraws its request altogether after receiving such notice from the Authority.

(2) Notwithstanding any other provision of this Rider L-16-EP or Schedule L to the contrary, the Authority shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time that the Authority, in its sole judgement, determines that (i) such Economy Power is no longer available and that continued use thereof by Customer will adversely affect service to the Authority's other customers and/or other utility systems with which the Authority is interconnected, or (ii) circumstances on the Authority's system and/or the systems of any other utility with which the Authority has an interchange arrangement are such that the Authority is unable to supply Economy Power at the Energy Price previously noticed by the Authority. When the Authority calls for such a curtailment, the amount of Economy Power scheduled for delivery to the Customer shall be deemed to be reduced accordingly.

(3) The Authority shall be under no obligation whatsoever to supply Economy Power in an hour in excess of the amount scheduled for delivery to the Customer as herein provided. Nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit deliveries to the Customer to the amounts so scheduled.

Section 5. Other Terms and Conditions

Service under this Rider L-16-EP, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Adopted _____________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes: Schedule L-13-EP,
Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVIC AUTHORITY
(SANTEE COOPER)
L-16-EP-O
Economy Power Service Rider
Optional Energy Charge

Section 3(E) of Rider L-16-EP provides that the Authority may offer pricing alternatives to customers served under the Rider. In accordance with this provision, the Authority offers an Optional Energy Charge as set forth below.

Notwithstanding any provision of L-16-EP to the contrary, an Economy Power (EP) customer, at its sole discretion, may elect to receive its entire Economy Power Service under the following terms and conditions.

a) The monthly Reservation Charge hereunder shall be equal to the Customer's Economy Power Contract Demand for such billing month, in kilowatts, times $3.53 per kilowatt.

b) The Hourly Energy Charge during Off-Peak Periods shall be:

(1) Base Energy Charge:

All kWh @ ………………………………………… $0.0375/kWh

(2) Fuel Adjustment Charge:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-16, or its successor clause, with "Fb/Sb" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.085, respectively.

The Hourly Energy Charge during On-Peak Periods shall be determined as set forth in section 3(C) of the L-16-EP Rider, or its successor.

c) For the purposes of this pricing alternative, "Off-Peak Periods" shall consist of all time periods not designated as On-Peak Periods. Except as provided for in Sections (d) and (e) herein, "On-Peak Periods" shall normally consist of the hours specified in the following table:

Season	On-Peak Hours
Summer (May – September)	11:00 a.m. – 11:00 p.m.
Winter (January, February, November, December)	5:00 a.m. – 11:00 a.m. 5:00 p.m. – 11:00 p.m.
March, April and October	All Off-Peak

d) During the months of January February, and December, the Authority reserves the right to designate additional On-Peak hours as set forth below:

(1) When the Authority determines that its estimated system daily peak demand will be greater than 90% of the projected system peak demand for that winter season (based on the Authority's most recent load forecast), then the Authority may, at its option and

with day ahead notice, designate up to twelve additional hours per day as On-Peak hours.

(2) If the Authority, in accordance with the criteria set forth in Section (d)(1) above, finds it necessary to designate additional On-Peak hours, it will notify affected customers by 12:00 noon on the current day for the following business or non-business day(s).

(3) The ability of the Authority to designate additional On-Peak hours in accordance with this Section (d) shall be limited to no more than seven days per month in each of these months.

e) During the months of March, April and October, the Authority reserves the right to designate additional On-Peak hours as set forth below:

(1) When the Authority projects its Incremental Energy Cost, as set forth in the Economy Power Service Rider, L-16-EP, or its successor, will equal or exceed $55.00/MWh, then the Authority may, at its option and with day ahead notice, designate up to twelve hours per day as On-Peak hours.

(2) If the Authority, in accordance with the criteria set forth in Section (e)(1) above, finds it necessary to designate additional On-Peak hours, it will notify affected customers by 12:00 noon on the current day for the following day.

(3) The ability of the Authority to designate additional On-Peak hours in accordance with this Section (e) shall be limited to no more than seven days per month in each of these months.

f) The Customer will continue to schedule all Economy Energy usage during Off-Peak Periods; failure to schedule may result in discontinuance of this pricing alternative by the Authority to the Customer.

g) Unless specifically contradicted above, all other provisions of Rider L-16-EP, or its successor, remain in effect. The Authority, in its sole judgment, shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time.

h) This pricing alternative is in effect until modified or withdrawn. This pricing alternative is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted ______________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
L-13-EP Economy Power Service Rider
Optional Energy Charge, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVIC AUTHORITY
(SANTEE COOPER)
L-16-EP-AU
Experimental Economy Power Service Rider
As-Used Billing Option

Section 3(E) of Rider L-16-EP provides that the Authority may offer pricing alternatives to customers served under the Rider. In accordance with this provision, the Authority offers an As-Used Billing Option as set forth below.

Service hereunder shall be limited to ten percent (10%) of the Customer's total contract demand. Total contract demand shall refer to the sum of the Firm Contract Demand plus the Customer's Contract Demand(s) (if any) under any and all riders hereto and other rate schedules of the Authority, exclusive of Nominated or curtailed capacity as provided under L-16-DRB.

Notwithstanding any provision of L-16-EP to the contrary, an Economy Power (EP) customer, at its sole discretion, may elect to receive its entire Economy Power Service under the following terms and conditions, subject to the limitation above.

a) Service taken under this rider shall not be subject to the Monthly Reservation Charge as defined in Section 3(B) of the L-16-EP rider.

b) The Hourly Energy Charge during On-Peak Periods shall be determined as set forth in Section 3(C) of the L-16-EP Rider, or its successor.

c) The Hourly Energy Charge shall include a charge equal to $0.01994/kWh in addition to all the applicable Hourly Energy Charges listed above.

b) For the purposes of this pricing alternative, "On-Peak Periods" shall consist of the time periods set forth in Section 5(A) of Schedule L-16 or it's successor.

c) Energy taken under this pricing alternative shall not be available during off-peak periods, including any additional off-peak hours as set forth in Section 5(A)(2) of Schedule L-16 or it's successor.

d) Unless specifically contradicted above, all other provisions of Rider L-16-EP, or its successor, remain in effect. The Authority, in its sole judgment, shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time.

f) This pricing alternative is in effect until modified or withdrawn. This pricing alternative is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted _____________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes:
None

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
STANDBY SERVICE
RIDER L-16-SB

Section 1. Availability

(A) Service hereunder, "Standby Power", is available to those customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-16 or its successor (hereinafter, "Schedule L"), to which this Rider L-16-SB is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-16-SB, the sum of the Customer's Firm Contract Demand and Interruptible Contract Demand must equal or exceed 1,000 kW.

(C) Standby Power shall be that power used to provide standby or replacement service which, in the opinion of the Authority, the Authority has available at any location, to a Customer having another source of electrical power not held solely for emergency use, or another source of electrical power for peak-shaving purposes, both for which the Authority's service may be substituted directly or indirectly.

Section 2. Character of Service

(A) Standby Power hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L that (i) is in excess of Firm Power purchased by the Customer under Schedule L; and Interruptible Power, if any, purchased by the Customer under Rider L-16-I; and Economy Power, if any, purchased by the Customer under Schedule L-16-EP, and (ii) is deemed, in the opinion of the Authority, to be available for use by the Customer.

(B) The Customer shall use its best reasonable efforts to coordinate its requirements for Standby Service with the Authority, including (but not limited to) scheduling maintenance outages of Customer-owned generation to occur at times agreeable to the Authority. In no event shall the Authority be required to supply Standby Service at times when it shall have interrupted or curtailed service to any other retail customer. In no event shall the Authority be required to supply Standby Service on more than sixty (60) days out of any twenty-four (24) consecutive months.

Section 3. Monthly Rates and Charges

The monthly charge for Standby Power shall consist of the following charges:

(A) Monthly Standby Reservation Charge

The Monthly Standby Reservation Charge hereunder shall be equal to the Customer's Standby Power Contract Demand for such Billing Month, in kilowatts, times $3.53 per kilowatt.

(B) Monthly Standby Demand Charge

All kW of Standby Billing Demand @ ....$13.77 /kW

(C) Monthly Energy Charge

The Monthly Energy Charge for Standby Power Service shall be calculated by multiplying the total amount of kilowatt-hours of Standby Power delivered to the Customer during the current month by the Monthly Standby Power Energy Rate for such month. The Monthly Standby Power Energy Rate for a month shall be the sum of (i) the Authority's Average Monthly Fossil Fuel Cost Rate and (ii) the Authority's then current Non-Fuel Energy Cost, both as hereinafter defined.

The Authority's Average Monthly Fossil Fuel Cost Rate for each month shall be determined by the following formula:

$$F = 100 * (Fm/Gm) * (1/(1-K)) * (1/(1-L))$$

where:

F = Average Monthly Fossil Fuel Cost Rate in cents per kilowatt-hour, rounded to the nearest one-thousandth of a cent.

Fm = the Authority's total dollar fossil fuel cost for the current month, which shall be equal to the sum of:

(a) the cost of fossil fuel burned or used, including the net cost of allowances expensed concurrent with regulated emissions, in the Authority's own plants and the Authority's share of fossil fuel burned or used in jointly owned or leased plants as such costs are recorded in Accounts 501, 509, and 547; plus

(b) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the authority to substitute for its own higher cost energy; plus

(c) the actual identifiable fossil fuel cost associated with energy purchased for reasons other than identified in (b) above; less

(d) the cost of fossil fuel recovered through inter-system sales including, without limitation, the fuel cost related to economy sales and other energy sold on an economic dispatch basis.

Gm = the Authority's fossil net generation, in kilowatt-hours, for the current month, which shall be equated to the sum of:

(a) the net generation of the Authority's own fossil-fueled plants and the Authority's shares of jointly owned or leased fossil-fueled plants; plus

(b) interchange in; plus

(c) the fossil-generated energy purchased by the Authority other than interchange; less

(d) the net fossil-fueled generation associated with inter-system sales referred to in Fm(d) above.

K = the Authority's allowance for capital improvements, which, for the purposes of this Rider, shall be nine percent (9.0%), expressed as a decimal fraction.

L = the Authority's allowance for transmission and distribution system losses applicable to service to the Customer, expressed as a decimal fraction.

The Authority's Non-Fuel Energy Cost shall be the rate, in cents/kWh, obtained by subtracting (a) the product of (i) 1/(1-K), where "K" is defined above, and (ii) the base fuel cost (Fb/Sb) contained in the Authority's then applicable Fuel Adjustment Clause (FAC) from (b) the Energy Charge set forth in the Authority's then applicable Large Light and Power Rate Schedule (Schedule L).

Section 4. Determination of Demands

(A) Standby Power Billing Demand

The Customer's Standby Power Billing Demand for each Billing Month shall be the amount, if any, by which the Customer's Measured Demand for such month, determined pursuant to Section 4(B) of Schedule L, exceeds the sum of (i) the Customer's then-current Firm Contract Demand, under Schedule L, and (ii) the Customer's Economy Power Contract Demand, if any, under Rider L-16-EP; provided however, that in no event shall such Standby Billing Demand be greater than the Customer's Standby Power Contract Demand. Any Measured Demand exceeding the Customer's total Contract Demand for such month shall be Excess Demand in accordance with Section 4(D) of Schedule L.

If a Customer fails to satisfy the requirements of Section 2(B) above, the Authority may, at its sole option, require the Customer to pay for all Standby Billing Demand at the rate specified in Section 3(A)(2)(a) of Schedule L, until such time as the Customer satisfies the constraints of Section 2(B) above.

(B) Standby Power Contract Demand

(1) Except as otherwise provided herein, the Customer's Standby Power Contract Demand shall be the maximum amount of Standby Power, in kilowatts, that the Customer has requested and the Authority has agreed to supply, as evidenced in the Delivery Point Specification Sheet for which the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer may reduce its Standby Power Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month periods, by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of the Service Agreement between the Customer and the Authority, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Standby Power Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Standby Power Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Standby Power Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Standby Power Contract Demand(s) for such years.

Notices of such reductions in the Customer's Standby Power Contract Demand shall be irrevocable once given.

(3) The Customer's Standby Power Contract Demand, once established or reduced, may be increased only by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(4) The total amount of Standby Power available for sale to all customers changes from time to time. In initially determining the amount of Standby Power, if any, to provide a Customer and/or in determining the amount, if any, by which a Customer's Standby Power Contract Demand may be increased, the Authority shall take into account the total amount of such Standby Power it reasonably expects to be available and its prior commitments for sales of such power. If, and to the extent that, the Authority thus determines it can make additional Standby Power available to new Customers and to existing Customers, the Authority shall do so on a first-come, first-served basis.

Section 5. Other Terms and Conditions

Service under this Rider L-16-SB, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted ___________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule L-13-SB, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
DEMAND RESPONSE BUY BACK (DRB)
SCHEDULE L-16-DRB

Section 1. Limited Availability

(A) Service hereunder, "Demand Response Buy Back," is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-16 or its successor (hereinafter, "Schedule L"). In addition, service hereunder shall be available only to specified Delivery Points upon a prior written Service Agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Schedule:

1. The sum of the Customer's Contract Demand under this Schedule L-16-DRB plus the Customer's Firm Contract Demand must equal or exceed 1,000 kW,

2. The Customer's electrical wiring permits separate metering of the Customer's equipment and facilities,

3. The Customer's designated equipment and facilities must be totally and responsively interruptible at the direction of the Authority or its designated representatives,

4. The Customer, at its expense, shall cause the following to be installed:

   a) Dedicated telephone and data lines for the exclusive use of the Customer and the Authority,

   b) All communications and control equipment required by the Authority,

   c) Separate metering provided by the Authority to enable the Authority to separately meter the Customer's designated equipment and facilities.

5. The Customer agrees to hold the Authority and its designated representatives harmless from any and all claims, for damages resulting from interruption or curtailment of electric service provided under this Schedule. (See Section 7 - Special Provisions.)

(C) The total amount of Demand Response Buy Back service available to all qualifying customers shall be determined solely by the Authority and such amount changes from time-to-time. As of January 1, 2012, the Authority has determined that Demand Response Buy Back service will be made available to qualifying customers on a "first come first served" basis up to a maximum aggregate amount of 300 MW.

Section 2. Character of Service

Demand Response Buy Back hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L and Interruptible Service Rider L-16-I that is interruptible or curtailable by the direction of the Authority in accordance with the following terms:

(A) Demand Response Buy Back shall be interruptible or curtailable service with a short Customer notice and short interruption duration that is applicable to the Customer's equipment and facilities. Short notice will be two (2) minutes or less with usual customer notification and short duration will be limited to sixty (60) minutes from the onset of the interruption or curtailment.

(B) During a System Disturbance or Emergency, Demand Response Buy Back service shall typically be the first type of service to be interrupted or curtailed and interruption and curtailment will be ratably administered among Customers receiving such service as determined by the Authority (see Operational Guidelines for Curtailment and/or Interruption of Curtailable or Interruptible Loads).

(C) The Authority shall have the right, at any time or times and for any reason or reasons, to direct the interruption of all or part of the Demand Response Buy Back service, provided that the duration of such interruptions or curtailments is sixty (60) minutes or less, shall not exceed 200 hours, not occur in more than 60 days, in any calendar year and, provider further, that the number of interruptions or curtailments, other than during System Emergencies, shall not exceed two (2) in a calendar day. As used herein, a "System Disturbance or Emergency" means a condition on the Authority's system in which, in the sole judgment of the Authority's System Controller or designated representative, action is required to maintain compliance with approved Reliability Standards, or there is an imminent danger of deterioration of service to firm or higher priority customers, voltage collapse, or damage to a part of the system. The Authority shall establish and maintain operational guidelines (referenced above), which shall state the conditions and circumstances under which directions for interruptions and curtailments may be made. Such operational guidelines shall be published, and available for review, at the Authority's offices.

(D) When the Authority determines that a System Disturbance or Emergency is imminent or exists and/or determines the need to interrupt or curtail the Customer's Demand Response Buy Back service as provided herein, the Authority shall give notice thereof to the Customer by telephone or by such other means of communication as the Authority may from time-to-time designate. Each such notice shall specify a demand level of Demand Response Buy Back service, to which the Customer's use of Demand Response Buy Back service is to be limited and the anticipated time period (hereinafter, a "Curtailment Period") to which such limitation is to apply. After receiving such notice, the Customer shall, except as otherwise provided herein, reduce its use of power during the Curtailment Period to which the notice applied, to the level specified by the Authority. Each such notice shall be deemed received by the Customer if the Authority shall have issued or attempted to issue that notice.

(E) The Authority will use reasonable efforts to give as much advance notice as practicable of probable curtailments when circumstances permit. It is recognized that because of the Character of Service of this Schedule, Customer Notice by the Authority of a Demand Response Buy Back interruption or curtailment could be two (2) minutes or less and not more than ten (10) minutes prior to the expected initiation of the Curtailment Period.

(F) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period shall be classified as Excess Power and subject to penalties as set forth herein; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Power.

(G) Nominated demand for the Demand Response Buy Back service is not subject to the Authority's Demand Sales Adjustment Clause DSC-16, or its currently applicable successor clause, if any.

Section 3. Monthly Credits

For all Demand Response Buy Back service provided hereunder, the monthly credit for controlled load response during a Curtailment Period shall be based on a combination of the sum of Nominated Demand as specified by the Customer and the specified Monthly Credit ($/kW-month), and the sum of the Nominated Demand as specified by the Customer (regardless of the demand level requested by the Authority), the number of Curtailment Periods that have occurred within the billing period, and the specified Event Credit rate ($/Event per MW) as indicated below and, as follows:

(A) Monthly Credit

Nominated kW of Demand Response Buy Back Service……….……………..$(586.00)/MW

(B) Event Credit

For all service provided hereunder other than Excess Power, the Monthly Event Credit for Demand Response Buy Back Service shall be determined as follow:

1. Nominated MW of Demand Response Buy Back service ...._____ (MW)
2. Number of Curtailment Periods within billing period .... ______ (#)
3. Credit per Curtailment Period per MW .... $(293.00) ($/MW)
4. Total Credit (a * b * c) ....$____________

(C) Excess Power Charge

The price for Excess Power used by the Customer in each Curtailment Period shall be 200% of the Authority's reasonable best estimate of its incremental cost (including opportunity costs) of supplying such Excess Power and any penalties imposed on the Authority by the Regional and Sub-regional Reliability Councils and their Balancing Authority. Such incremental costs may include both demand-related and energy-related costs.

Section 4. Determination of Demands

The Customer's Demand Response Buy Back demand for each Delivery Point shall be established initially by mutual agreement of the Authority and the Customer, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and part of, the Service Agreement between the Customer and the Authority. The sum of the Customer's Demand Response Buy Back for each Delivery Point will serve as the basis for the Nominated MW of Demand Response Buy Back included in the calculation of the Monthly Credit in Section 3 above.

Section 5. Control Characteristics

(A) Frequency

The Control Conditions will typically result in less than twenty (20) Curtailment Periods per calendar year and will not exceed twenty (20) Curtailment Periods per calendar year.

(B) Notice

Notice for immediate customer action by the Authority of a Demand Response Buy Back interruption or curtailment could be two (2) minutes or less and not more than ten (10) minutes.

(C) Duration

The duration of a single Demand Response Buy Back Curtailment Period will be one (1) hour or less. Under typical circumstances, the Curtailment Period will not exceed one (1) hour.

(D) Major Disturbance

In the event of a major disturbance, as defined by the Authority, greater frequency, less notice, or longer duration than listed above may occur. In the event of a major disturbance, the Customer is not entitled to additional compensation beyond that indentified herein, regardless of greater frequency, less notice or longer duration. The Customer agrees that the Authority will not be liable for any damages or injuries that may occur as a result of the implications of a major disturbance, including, but not limited to, greater frequency, less notice (including no notice) or longer duration.

(E) Customer Responsibility

1. Upon the successful installation of the monitoring and load control equipment, a test of this communications and monitoring equipment will be conducted by the Authority. Testing will be conducted at a mutually agreeable time and date between Authority and Customer.

2. The Customer shall be responsible for providing and maintaining the appropriate equipment required to interrupt or curtail the Customer's load within the required time as specified by the Authority and upon receiving notice from the Authority, as specified in the Service Agreement between the Customer and the Authority.

3. The Authority will direct the interruption or curtailment of a portion or all of the Customer's Nominated Demand Response Buy Back service for up to a one (1) hour period once per year for testing purposes at a mutually agreeable time and date, if the Customer's load has not been successfully controlled during a load control event in the previous twelve (12) months. Testing purposes include the testing of the load control equipment to ensure that the Customer's load is able to be monitored by the Authority within the agreed upon specifications.

Section 6. Term of Service

Service under this Schedule shall continue, subject to Limitation of Availability, until terminated by either the Authority or the Customer upon written notice given at least five (5) years prior to termination. The Authority may terminate service under this Schedule at any time for the Customer's failure to comply with the terms and conditions of this Schedule or the Service Agreement. Prior to any such termination, the Authority shall notify the Customer at least thirty (30) days in advance and describe the Customer's failure to comply. The Authority may then terminate service under this Schedule at the end of the 30-day notice period unless the Customer takes measures necessary to eliminate, to the Authority's satisfaction, the compliance deficiencies described by the Authority. Notwithstanding the foregoing, if, at any time during the 30-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Authority shall be entitled to suspend forthwith the monthly credits under this Schedule.

Section 7. Special Provisions

(A) Monitoring of the Customer's load shall be accomplished through the Authority's use of monitoring circuits connected directly to the Customer's switching equipment of the Customer's load and may be controlled by use of other means acceptable to the Authority.

(B) The Customer shall grant the Authority reasonable access for installing, maintaining, inspecting, testing and/or removing Customer-owned communications and monitoring load control equipment.

(C) It shall be the responsibility of the Customer to determine that all of its electrical equipment to be controlled is in good repair and working condition. The Authority will not be responsible for the repair, maintenance, or replacement of the Customer's electrical equipment.

(D) The Authority will not be required to install load monitoring equipment if the installation cannot be economically justified.

(E) Credits under this Schedule will commence after the installation, inspection, and successful testing of the load monitoring equipment. Credits are applied to specific Curtailment Periods only, as requested by the Authority and responded to by the Customer.

(F) The Customer shall hold the Authority and its designated representatives harmless from any and all claims, actual or threatened, for economic or punitive damages including but not limited to life, safety, equipment, facilities product, inventory, and opportunity resulting from interruption or curtailment of electric service provided under this Schedule and the Service Agreement.

(G) Service under this Schedule is subject to the terms of the currently effective Schedule L and/or Schedule L - Interruptible, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Pricing for DRBB provided herein is in effect until modified or withdrawn. This pricing is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted [date]

Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule L-13-DRB, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
EXPERIMENTAL
LARGE LIGHT AND POWER
ECONOMIC DEVELOPMENT SERVICE
RIDER L-16_ED

SECTION 1. Availability:

(A) Service hereunder, "Economic Development Service" (hereinafter, "Rider) is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-16 or its successor (hereinafter, "Schedule L"), to which this Rider is attached and made a part of. In addition, service hereunder shall be available only to New Load.

(B) New Load, as used herein, is load that was not served by the Authority prior to the initial effective date of this Rider, and has been determined by the Authority as economic development of the Authority's service area in accordance with Section 1 (C), below. For existing Customers, New Load is the net incremental load (a) above that which existed and (b) was not served by the Authority under Schedule L or under riders L-16-I, L-16-EP, L-16-EP-O, and L-16-SB, or their successors, prior to the initial effective date of this Rider or, by load served directly from power and energy requirements purchased by a Wholesale Customer from the Authority. Wholesale Customers as used herein shall mean a municipal corporation, electric cooperative, or joint municipal power agency organized under the laws of the State of South Carolina that is a long-term, firm wholesale customer of the Authority. As used herein, New Load does not include: replacement electrical machines, equipment or processes; load shifted from one Delivery Point on the Authority's system to another on the Authority's system; load that existed and was served by another electric provider prior to that load being served by the Authority. All qualifying New Load for either a new or existing customer shall not exceed 40 MWs per customer per delivery point. Furthermore, the aggregate amount of New Load available to all Authority customers shall not exceed 300 MWs.

(C) Contribution of New Load to Economic Development: In order to receive service for this Rider, the "Customer" shall have:

i. Requirements for service hereunder of at least 1,000 kW of load under this Rider (hereinafter "Firm-ED Load"), **and**;
ii. Must employ an additional workforce within the Authority's service area of a minimum of thirty-five (35) full time equivalent (FTE) employees per 1,000 kW demand of Firm-ED Load during the Contract Period, **or**, must result in a minimum capital investment within the Authority's service area of $500,000 per 1,000 kW demand of Firm-ED Load.

(D) Service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(E) This Rider is not available for renewal of service for a period of time following interruptions such as equipment failure, temporary plant shutdown, strike, or cessation of operations due to economic conditions. This period of time is the longer of either one year or the Notification Period as defined in individual customer contracts. However, if change of ownership occurs after the customer contracts for service under this Rider, the successor customer may be allowed to fulfill the balance of the contract under this Rider and continue to receive the discount as outlined in this Rider, subject to the eligibility requirements and other provisions hereof.

(F) This Rider is applicable and available to new applicants through December 31, 2014. Additionally, service hereunder is made available by the Authority on an experimental, pilot-program basis. Accordingly, the availability of such service, the terms and conditions thereof, and the operational aspects of such service are subject to termination or change, in whole or in part; provided, however, that this Rider will remain in effect for any Customer who has been approved to receive service.

SECTION 2. Character of Service:

Electric power and energy delivered shall be of the same character as that described in Section 2 of Schedule L, which is incorporated herein by reference.

SECTION 3. Monthly Billing Rates:

The charges for service hereunder shall consist of the following:

(A) Demand Charge:

The monthly Demand Charge per Firm-ED kW shall be determined as follows:

Demand Charge per Firm-ED kW = Schedule L Base Demand Charge – ED Discount

Where the ED Discount is determined by taking a percentage of the base demand charge as stated in the then-current Schedule L, whereas, the ED Discount is set forth in the following table:

Months 1 – 12	**45% of Schedule L Base Demand Charge**
Months 13 – 24	**30% of Schedule L Base Demand Charge**
Months 25 – 36	**20% of Schedule L Base Demand Charge**
Months 37 – 48	**10% of Schedule L Base Demand Charge**
After Month 48	**No Discount**

(B) Energy Charge:

Same as the Energy Charge per kilowatt-hour and Fuel Adjustment Charge in Rate Schedule L.

(C) All other monthly charges per Schedule L will apply.

SECTION 4. General Provisions:

Customer must make an application to the Authority for service of New Load under this Rider and Authority must approve such application before Customer may receive service hereunder. The application must include a description of the amount of and nature of the new or additional load and the basis on which the Customer qualifies as set forth in Section (1) above. In the application, Customer must affirm that availability of this Rider was a factor in Customer's decision to locate the New Load on Authority's system. The application shall also specify the total number of full time equivalent employees (FTE) employed by Customer in all establishments receiving electric service from Authority's system, at the time of application for this Rider, as well as the additional FTE attributed to the New Load. Alternatively, Customer must include a description of the minimum capital investment requirement,

including verification of the value of the declared capital investment. The Authority reserves the right to verify at any time during the Contract Period (as defined in Section 5) that the Customer satisfies the availability and eligibility requirements set forth in Section 1 hereof. Customer shall provide a statement to the Authority, verified by an officer of the Customer or their designee, that the Customer satisfies the availability and eligibility requirements of the Rider. This statement will be required annually during the Contract Period from the operational date of the new or expanded facility. The operational date of the new or expanded facility that results in New Load shall be no more than one year from date of application.

SECTION 5. Contract Period:

Each Customer shall enter into a Service Agreement to purchase electricity from the Authority for a minimum initial term of 8 years from the date the new or expanded facility is fully operational as declared by the Customer, herein defined as the Contract Period. Thereafter, either party can terminate the Service Agreement at the end of the initial Contract Period as provided in the terms and conditions of the then-applicable Schedule L. Service Agreement will include specified Contract Demand for Firm-ED Load which meets the requirements as stated in Section 1 of this Rider. An individual establishment and/or physical location will not be allowed to receive ED Discounts for more than four (4) years under this Rider, unless the Authority, at its sole discretion, agrees to accept and approve a new application and contract for qualifying New Load.

Discounts under this Rider shall begin no earlier than the operational date of the new or expanded facility and shall end 48 months after the later of (i) operational date of the facility, provided that such operational date shall be no more than one year after the application date, or, (ii) the date the Customer's first bill is rendered under this Rider.

If at any time during the term of contract under this Rider, Customer violates any of the terms and conditions of the Rider or the Service Agreement, Authority may discontinue service under this Rider without notice and bill Customer under the applicable schedule without further ED Discounts. In the event electric service is terminated or discontinued under this Rider by the Customer or the Authority, or the Contract Demand for Firm–ED is reduced by Customer before the end of the Contract Period, Customer shall pay Authority, in addition to all other applicable charges, the sum of all ED Discounts received, plus interest compounded annually, for the Firm-ED Load that will no longer be served by Authority. The rate of interest shall be the rate per annum which will be based on the then current LIBOR index. The Authority shall have the right to adjust the total payment required by the Customer, as previously described, at its sole discretion.

SECTION 6. Other Terms and Conditions:

Except as otherwise provided in this Rider, service hereunder shall be subject to all terms and conditions of the then-applicable Large Light and Power Rate Schedule L.

The Delivery Date is the first date service is supplied under the contract.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted ____________, 2015
Effective for bills rendered on and after April 1, 2016.

Supersedes:
Schedule L-13-ED-02, Effective May 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
ECONOMIC DEVELOPMENT SALES ADJUSTMENT CLAUSE
(EDA-16)

Section 1. Purpose:

The Economic Development Rates (Riders L-13-ED-02 & L-14-ED-T) were approved by the Authority's Board of Directors on April 26, 2013 and April 25, 2014, respectively. The Economic Development Rates are available to customers who qualify that are directly served by the Authority as well as Wholesale Customers indirectly served by rider. Wholesale customers as used herein shall mean a municipal corporation, electric cooperative, or joint municipal power agency organized under the laws of the State of South Carolina that is a long-term, firm wholesale customer of the Authority. The purpose of this clause is to credit the Authority's firm-requirements and interruptible service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority from the direct and indirect sales associated with Economic Development Service Riders L-13-ED-02 & L-14-ED-T or their successors, or, associated Rider as provided in memorandum of understanding and agreement between the Authority and its customers, to the extent that such sales may not be reflected in the currently effective rates for such firm-requirements and interruptible service customers.

Section 2. Applicability:

The Economic Development Sales Adjustment Clause is applicable, to and becomes a part of, all of the Authority's published rate schedules that so specify.

Section 3. Adjustment of Bills:

Each customer's current monthly bill, as computed under the appropriate rate schedule, will be decreased by an amount equal to the result of multiplying (i) the appropriate rate "D" (as defined below), times (ii) either (a) in the case of each Large Light & Power ("Industrial") customer, that customer's current Firm Billing Demand and Interruptible Billing Demand, excluding L-13-ED-02 & L-14-ED-T Rate customers' load, or portions of load thereof, or (b) in the case of each Municipal Light & Power ("Municipal") customer, that customer's current Billing Demand, or (c) in the case of each other type of customer ("Distribution Service" customers), the total billed kWh of energy for the period to which the bill applies. Rate Riders L-13-ED-02 & L-14-ED-T Service customers, or portions of service thereof, are excluded from the Economic Development Sales Adjustment Clause during the period of the discount as defined in L-13-ED-02 & L-14-ED-T and specific to each customer's load or portion of customer's load thereof.

The rate D shall, for each respective customer class, be determined as follows:

$$D = R_D / B_D$$

Where:

D = The adjustment rate factor, in dollars per kW for Industrial and Municipal customers and in dollars per kWh for Distribution Service customers, in each case, rounded to the nearest one-thousandth of a cent.

R_D = The total demand-related or capacity-related revenues associated with Economic Development Riders L-13-ED-02 & L-14-ED-T for the preceding month allocated to the customer class (Industrial [as modified above], Municipal, or Distribution Service), based on the projected average four-month class coincident peak demand contributions for the current calendar year, as set forth in the Authority's then most recently adopted load forecast.

B_D = The projected total billing units for the customer class to which the adjustment rate factor, D, is to apply, for the current month, in kW for Industrial (as modified above) and Municipal customer classes and in kWh for Distribution Service customer classes.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule EDA-12, Effective December 1, 2012

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
FUEL ADJUSTMENT CLAUSE
FAC-16

Applicability:

This Fuel Adjustment Clause is applicable to and becomes a part of each of the Authority's published Rate Schedules and rate riders thereto that so specify.

Adjustment of Bills:

Each monthly bill, computed under the appropriate Rate Schedule and appropriate rate riders, will be increased or decreased by an amount equal to the result of multiplying the measured or used kWh by the factor F, determined as follows:

$$F = (F_m/S_m - F_b/S_b) \times (1 / 1\text{-}K)$$

Where:

1. F = Adjustment factor in dollars per kWh rounded to the nearest one-thousandth of a cent.

2. F_m = Total fuel and purchased power cost for the three preceding months, consisting of the costs of:

   a. the cost of fossil, nuclear and renewable fuel consumed, including the net cost of allowances expensed concurrent with regulated emissions, in the Authority's own plants and the Authority's share of fossil, nuclear and renewable fuel consumed in jointly owned or leased plants, plus

   b. the actual identifiable fossil, nuclear and renewable fuel costs associated with energy purchased for reasons other than identified in (c) below, plus

   c. the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Authority to substitute for its own higher cost energy, less

   . d. the cost of fossil, nuclear and renewable fuel recovered through inter-system sales and any applicable non-firm intra-system sales (such as Economy Power, Secondary Power), including the fuel costs recovered through economy energy sales and other energy sold on an economic dispatch basis.

3. S_m = kWh sales which shall be equated for the three preceding months to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) sales referred to in F_m (d) above, less (vi) average annual power supply transmission losses in decimal form times the net sum of (i), (ii), (iii), (iv), and (v) in this definition of S_m.

4. F_b/S_b = \$0.03641

Where:

a. F_b = Total estimated fuel cost in the base period.

b. S_b = Total estimated kWh sales for the base period.

5. K = Allowance for capital improvements and distribution losses, as set forth in each Rate Schedule and applicable rate riders to which this Clause applies.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule FAC-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
DEMAND SALES ADJUSTMENT CLAUSE
(DSC-16)

Section 1. Purpose:

The purpose of this Clause is to credit the Authority's firm-requirements and Interruptible Service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority through Non-Class Sales, to the extent that such sales may not be reflected in the currently effective rates for such firm-requirements customers. Such demand-related and capacity-related revenues shall mean charges recovered on a kilowatt (kW) or reservation basis as well as charges recovered through a kilowatt-hour (kWh) basis from Section c of rider L-16-EP-AU. As used herein, "Non-Class Sales" consist of (i) off-system, inter-utility sales, and (ii) non-firm, non-requirements, on-system sales (such as sales of Interruptible Power and Standby Power, pursuant to the Authority's Large Light & Power Rate Schedule and the currently effective riders thereto).

Section 2. Applicability:

The Demand Sales Adjustment Clause is applicable, to and becomes a part of, all of the Authority's published rate schedules that so specify.

Section 3. Adjustment of Bills:

Each customer's current monthly bill, as computed under the appropriate rate schedule, will be decreased (or, when applicable, increased) by an amount equal to the result of multiplying (i) the appropriate rate "D" (as defined below), times (ii) either (a) in the case of each Large Light & Power ("Industrial") customer, that customer's current Firm Billing Demand, or (b) in the case of each Municipal Light & Power ("Municipal") customer, that customer's current Billing Demand, or (c) in the case of each other type of customer ("Distribution Service" customers), the total billed kWh of energy for the period to which the bill applies. For Interruptible Service customers, Non-Class Sales are exclusive of non-firm sales specific to Interruptible Power.

The rate D shall, for each respective customer class, be determined as follows:

$$D = (R_m - R_b) / B_m$$

Where:

D = The adjustment rate factor, in dollars per kW for Industrial and Municipal customers and in dollars per kWh for Distribution Service customers, in each case, rounded to the nearest one-thousandth of a cent.

R_m = The total revenues from Non-Class Sales for the preceding month allocated to the customer class (Industrial, Municipal, or Distribution Service), based on the projected average four-month class coincident peak demand contributions for the current calendar year, as set forth in the Authority's then most recently adopted load forecast. For Interruptible Service customers, Non-Class Sales exclude non-firm sales specific to Interruptible Power.

R_b = The allocated revenues from Non-Class Sales, reflected in the currently effective rate(s) for the customer, which shall, for purposes of this Clause, be the following amounts:

a. For Firm Industrial customers: $55,000 per month beginning April 1, 2016 .

b. For Interruptible Industrial customers: $120,000 per month beginning April 1, 2016.

c. For Municipal customers: $12,000 per month beginning April 1, 2016.

d. For Distribution Service customers: $303,000 per month beginning April 1, 2016.

B_m = The projected total billing units for the customer class to which the adjustment rate factor, D, is to apply, for the current month, in kW for Industrial and Municipal customer classes and in kWh for Distribution Service customer classes.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2016

Supersedes:
Schedule DSC-13, Effective December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
POLE ATTACHMENT
SCHEDULE PA-16

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable to all telephone companies, cable television and other such communication companies for the purpose of attaching their lines, cables, wireless or other non-linear devices to the Authority's distribution poles. When a telephone company and a cable company are affiliated, they shall nevertheless be treated as separate entities and will be billed separately for each attachment.

Section 3. Rates and Charges:

(A) Annual Pole Attachment Billing Rate

1. The annual charge for service hereunder shall be $14.60 for each attachment for each year (or portion of a year).

(B) Monthly Energy Charge

1. Customers shall be responsible for any electrical energy consumption in kilowatt-hours of its attachments and/or associated communication equipment, based on the full power ratings of said devices/equipment.

2. Energy Charge:
   a) Base Energy Charge:
      All kWh ……………………………………………………………………$0.1000/kWh

(C) Fuel Adjustment Clauses

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-16, or its currently applicable successor clause, if any, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(D) Taxes

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above annual rate. The charges computed at the above rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Payment:

Joint attachment bills will be rendered annually on a net basis. Energy bills (when applicable) will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased by the greater of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges.

Section 5. Terms and Conditions:

(A) Linear Pole Attachment:

In order to receive service hereunder, the Customer shall be required to enter into a contract with the Authority in the form Attachment A hereto (Linear Pole Attachment Service Agreement), which shall govern the provision of such service by the Authority and the use of such service by the Customer.

(B) Non-Linear Pole Attachment:

In order to receive service hereunder, the Customer shall be required to enter into a contract with the Authority in the form Attachment B hereto (Non-Linear Pole Attachment Service Agreement), which shall govern the provision of such service by the Authority and the use of such service by the Customer.

Adopted _______________, 2015
Effective for bills rendered on and after April 1, 2015.

Supersedes: Schedule PA-13, December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
Service Agreement
For
Linear Pole Attachment Service

This Agreement made and entered this ______ day of _____________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and ________, hereinafter referred to as the "Customer".

1. The parties hereby terminate any and all prior agreements providing for the attachment of the Customer's communication facilities to the Authority's poles.

2. Whenever during the term of this agreement the Customer wishes to install any of its wires or appurtenances upon any poles of the Authority, the Customer shall give written notice of such intention to the Authority, identifying the poles and describing the facilities it wishes to install thereon. As soon as reasonably possible after receipt of such notice the Authority shall, in writing, either consent to such installation or refuse such consent, but such consent shall not be unreasonably withheld.

3. If the Authority consents to such use, the Customer shall have the right to install and maintain its facilities on said poles at the locations and in the manner specified by the Authority, in accordance with the terms and provisions herein contained, and shall pay the annual charge contained in the Authority's Pole Attachment Schedule PA-16 or successor schedules.

4. The Customer shall provide the Authority prompt written notice of the removal of any wires and appurtenances from the Authority's poles, identifying the poles and describing the facilities removed.

5. (A) All installation, attachments, operations and maintenance of the Customer's facilities shall comply with all federal, state and local regulations, including, but not limiting the generality of the foregoing, the requirements set forth in the American National Standards, ANSI C2-2012 entitled "National Electric Safety Code" or such successor publication.

   (B) In addition to paragraph (A), all employees, agents or contractors of the Customer shall comply with the following requirements:

   1. Such employees, agents or contractors shall not approach nearer than five (5) feet to any energized electric circuit.
   2. Electrical hard hats shall be worn by all workers.
   3. All ladders must have safety straps.
   4. All employees, agents or contractors shall be properly secured while working from ladders or buckets.
   5. All employees, agents or contractors shall be sufficiently trained by the Customer to identify electric supply circuits in order to maintain required clearances, and the Customer shall, upon request, provide the Authority a certified copy of its safety training program.

6. (A) On the first day of January of each year of the term of this agreement, the Customer shall pay to the Authority the annual charge contained in the Authority's Pole Attachment Schedule PA-16 or successor schedules for each attachment used in any way by the Customer during the preceding calendar year, or any portion thereof.

   (B) The annual charge may be changed by the Authority from time to time and when so changed shall become effective at the time designated by the Authority and the annual charge for each calendar year in which there is such a change shall be prorated.

7. All of the Customer's facilities and property shall be installed, removed and maintained at the sole cost, risk and expense of the Customer. The Customer shall, at any time, at its own cost, risk and expense, upon written notice from the Authority, change, alter, improve, or renew it installations and facilities covered hereby in such manner as the Authority may direct.

   Should it become necessary at any time to change the location of any of the Customer's wires, cables, or other facilities from one position to another, such work may be done by the Authority at the sole cost, risk and expense of the Customer. The Customer shall not at any time make any changes in the location of its attachments to, or in the use of, the Authority's poles or facilities, without the written consent of the Authority.

8. (A) The Customer agrees to indemnify and hold the Authority harmless from the consequences of any property loss or damage, death or personal injury whatever, accruing or suffered or sustained from or by reason of an act, neglect or default of the Customer, its agents, servants or employees, in or about or in connection with the exercise of such attachment rights, or which may, in any manner or to any extent be attributable thereto, or to the presence of any property of the Customer upon the Authority's poles and whether or not acts, neglect or defaults on the part of the Authority, it agents, servants, or employees may have contributed to such loss, injury or damage, except that the Customer shall not be held responsible under this Agreement, for any loss of life, or personal injury or property damage accruing solely from the Authority's, its agents', servants', or employees' own negligence, without fault of the Customer, its agents, servants or employees.

   (B) Prior to the taking of any action with respect to any claim for loss or damage sustained as a result of the joint use of poles with claim for loss or damage is covered by the provisions of this Agreement, the Authority or the Customer, as the case may be, shall immediately upon being notified of the existence of such claim, notify the other party in writing of such claim and all particulars with respect thereto. In cases in which liability for such claim would, if proven, require the Customer to indemnify the Authority under this Agreement, the Authority shall make no settlement or disposition of such claim without written approval of the Customer. Should the Customer and the Authority disagree concerning the liability for any particular claim for which the Customer would have to indemnify the Authority under this Agreement, the Customer may defend against such claim in any action at law or equity, the cost of such defense litigation to be borne solely by the Customer. The Customer's obligation to indemnify the Authority shall not arise until after final disposition by lawful authority of the liability for any claim so defended against. The Authority agrees to cooperate fully with the Customer in the defense of any such claims. Where both the Authority and the Customer dispute any claim for loss or damage arising from the joint use of poles, the Customer and the Authority agree to jointly defend against any claim for loss or damage sustained as a result of the joint use of poles, the cost of such litigation, if successful, to be borne equally by the parties.

9. The Authority makes no warranty as to its title or rights to any of the property herein referred to and only grants the rights to set out in this instrument insofar as the Authority's rights and titles extend. Nothing herein contained shall be construed as a representation or guarantee by the Authority to the Customer of permission from municipal or other public authorities or property owners for the exercise of any of the rights herein described or referred to. The Customer shall not assign, transfer, sublet or otherwise alienate any of the rights or privileges herein granted without the written approval of the Authority.

10. Either party may terminate this Agreement at any time by giving ninety (90) days advance written notice of such intention to the other party.

11. In addition to the right of termination contained in Section 10 hereof, the Authority in its discretion may at any time or times immediately terminate the use by the Customer on any or all attachments covered by this Agreement for any of the following causes:

(1) Installation, maintenance, or operation of facilities by the Customer at locations or positions on the Authority's poles other than those specified by the Authority or in a manner different from that so specified.

(2) Installation, maintenance, or operation of facilities by the Customer, in any way impairing, endangering or otherwise adversely affecting the system of the Authority.

(3) Objection or prohibition by municipal or any other public authorities, or by property owners, of or to any use of the Customer of the rights herein granted.

(4) The failure of the Customer to comply with any of the terms or provision of this Agreement.

Upon written notice by the Authority to the Customer that any of the above listed causes has arisen, the Customer shall forthwith remove, at its own expense, all of its facilities from any pole or poles as may be directed in said notice.

12. In the event that the Authority relocates its lines or poles, on which attachments of the Customer are located, it shall give prior notice of such intention to the Customer and, at the Customer's sole expense, the Customer may reattach its facilities to the relocated poles under the same conditions in their original locations.

If the Authority wishes to remove any pole or poles because of discontinuance of use by it of all or part of a line or lines, it shall have the right to do so notwithstanding the use thereof by the Customer. Where any such pole or poles are being used by the Customer, advance notice of the removal thereof shall be given to the Customer and the Customer shall remove its attachments from said pole or poles at its own expense and make any provisions necessary for the operation of its lines in such locations without any responsibility therefore by the Authority.

In either event, should the Customer fail to remove its attachments within the ninety (90) days after notification, the Authority shall have the right to remove or cause to be removed such attachments at the Customer's expense.

13. In cases where sufficient pole space for the Customer's attachment is not available on the Authority's poles, the Customer will pay the Authority all costs for installing a new pole of sufficient height less the salvage value of the pole replaced but including the cost of removal of the replaced pole.

14. In the event of any termination of the Agreement by either party under the terms of Section 10 hereof, or any termination by the Authority of the use of any pole or poles in accordance with Section 11 hereof, or the relocation or removal of lines or poles under Section 12 hereof, if the Customer fails to remove its facilities from any or all of the Authority's poles or systems covered by this Agreement, the Authority shall have the right to remove or cause to be removed the same, and the Customer shall pay to the Authority all costs and expenses of any such removal.

15. It is specifically understood by Customer that restoration of service which has been disrupted by any reason whatsoever shall be restored at the Authority's lowest priority level. Where multiple parties are involved in emergency restorations, access to the Authority's poles will be controlled by the Authority.

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed and their corporate seals to be hereunto affixed by their proper officers thereunto duly authorized as of the date hereinabove mentioned.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ______________________________	**BY:** ______________________________
ATTEST:	**(CUSTOMER)**
BY: ______________________________	**BY:** ______________________________

Adopted _________________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes: Attachment A, December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
Service Agreement
For
Non-Linear Pole Attachment Service

This Agreement made and entered this ______ day of _____________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and ________________________, hereinafter referred to as the "Customer".

1. Prior to installing any facilities, Customer shall submit written notice of intent to install to the Authority, identifying the poles and describing the facilities it wishes to install thereon. Upon review of the written notice of the intent to install, the Authority shall either accept or decline the proposal, and provide Customer with written notice of its decision, which shall constitute the initial installation of facilities ("Initial Installation"). Whenever during the term of this agreement Customer wishes to install additional facilities upon any poles of the Authority, Customer shall give written notice of such intention to the Authority, identifying the poles and describing the facilities it wishes to install thereon. As soon as reasonably possible after receipt of such notice the Authority shall, in writing, either consent or refuse such request. The Authority retains the right to limit the number of facilities installed pursuant to this agreement.

2. If the Authority consents to such use, Customer shall have the right to install and maintain its facilities on said poles at the locations and in the manner specified by the Authority, in accordance with the terms and provisions herein contained, and shall pay the annual charge recited herein. The Authority reserves the right to specify any devices, adapters, circuit breakers, fuses, conductors, and so forth used to derive a source of power from its facilities. An installation drawing for the power supply configuration may be prescribed by the Authority as it deems necessary.

3. Customer shall provide the Authority prompt written notice of the removal of any facilities from the Authority's poles, identifying the poles and describing the facilities removed.

4. All installation, attachments, operations and maintenance of Customer's facilities shall comply with all federal, state and local regulations, including, but not limiting the generality of the foregoing, the requirements set forth in the American National Standards, ANSI C2-2012, entitled "National Electric Safety Code" or such successor publication. All employees, agents or contractors of Customer shall comply with the following requirements:

    1. Such employees, agents or contractors shall not approach nearer than five (5) feet to any energized electric circuit.

    2. Electrical hard hats shall be worn by all employees, agents or contractors.

    3. All ladders must have safety straps.

    4. All employees, agents or contractors shall be properly secured while working from ladders or buckets.

    5. All employees, agents or contractors shall be sufficiently trained by Customer to identify electric supply circuits in order to maintain required clearances, and

Customer shall, upon request, provide the Authority a certified copy of its safety training program.

6. All equipment shall have a company logo affixed allowing utilities and others to readily identify Customer as the owner.

7. Any cords, cables, and conduits shall be securely strapped in a workmanlike manner.

5. On the first day of January of each year of the term of this agreement, Customer shall pay to the Authority the annual charge contained in the Authority's Pole Attachment Schedule PA-16 or successor schedules for each attachment used in any way by Customer during the preceding calendar year, or any portion thereof. In addition to the annual charge, Customer shall be responsible for the electrical energy consumption in kilowatt-hours of its devices and/or associated communication equipment, based on the full power ratings of said devices/equipment, and shall be billed in accordance with the annual charge contained in the Authority's Pole Attachment Schedule PA-16 or successor schedules

6. All of Customer's facilities and property shall be installed, removed and maintained at the sole cost, risk and expense of Customer. These costs shall include any and all assistance provided by the Authority for the installation of said facilities. Customer shall, at any time, at its own cost, risk and expense, upon written notice from the Authority, change, alter, improve, or renew its installations and facilities covered hereby in such manner as the Authority may direct. Customer shall not at any time make any changes in the location of its attachments to, or in the use of, the Authority's poles or facilities, without the written consent of the Authority.

   The Authority will not undertake the relocation or transfer of Customer's facilities on an Authority Pole, except in the event of emergency repair situations where the Authority's Pole or Customer's facilities are damaged. In such cases, Authority will reserve the right to transfer Customer's facilities that are still attached to the Authority's Pole, remove the damaged pole, leave the repair/replacement work for Customer, and bill Customer the actual costs incurred to perform the Attachment and/or Facility transfer of Customer's facilities.

7. Customer agrees to indemnify and hold the Authority harmless from the consequences of any property loss or damage, death or personal injury whatsoever, accruing or suffered or sustained from or by reason of an act, neglect or default of Customer, its agents, contractors, servants or employees, in or about in connection with the exercise of such attachment rights, or which may, in any manner or to any extent be attributable thereto, or to the presence of any property of Customer upon the Authority's poles and whether or not acts, neglect or defaults on the part of the Authority, its agents, servants, or employees may have contributed to such loss, injury or damage, except that Customer shall not be held responsible under this Agreement for any loss of life, or personal injury or property damage accruing solely from the Authority's, its agents', servants', or employees' own negligence, without fault of Customer, its agents, servants or employees.

   Prior to the taking of any action with respect to any claim for loss or damage sustained as a result of the joint use of poles with claim for loss or damage is covered by the provisions of this Agreement, the Authority or Customer, as the case may be, shall immediately upon being notified of the existence of such claim, notify the other party in writing of such claim and all particulars with respect thereto. In cases in which liability for such claim would, if proven, require Customer to indemnify the Authority under this Agreement, the Authority shall make no settlement or disposition of such claim without written approval of Customer. Should Customer and the Authority disagree concerning the liability for any particular claim for which Customer would have to indemnify the Authority under this Agreement, Customer shall defend against such claim in any action at law or equity, the cost of such defense litigation to be borne solely by Customer. The Authority agrees to cooperate fully with Customer in the defense of any such claims. Where both the Authority and Customer dispute any claim for loss or damage arising from the joint use of poles, Customer and the Authority agree to jointly defend against any claim for loss or damage sustained as a result of the joint use of poles, the cost of such litigation, if successful, to be borne equally by the parties.

8. Nothing herein contained shall be construed as a representation or guarantee by the Authority to Customer of permission from municipal or other public authorities or property owners for the exercise of any of the rights herein described or referenced. Customer agrees to obtain at its sole expense, all permits, approvals, licenses, conveyances, reliances, easements and authorizations from any and all State, Federal and Local Governmental agencies, and from any and all third parties, which may be necessary or desirable for the installation and maintenance of Customer's facilities. Customer shall not assign, transfer, sublet or otherwise alienate any of the rights or privileges herein granted without the written approval of the Authority.

9. Either party may terminate this Agreement at any time by giving ninety (90) days advance written notice of such intention to the other party. Upon termination, Customer shall pay to the Authority all amounts due and owing under this agreement, including but limited to any unpaid or unbilled annual charges.

10. In addition to the right of termination contained in Section 9 hereof, the Authority in its discretion may at any time or times immediately terminate the use by Customer on any or all attachments covered by this Agreement for any of the following causes:

    i. Installation, maintenance, or operation of facilities by Customer at locations or positions on the Authority's poles other than those specified by the Authority or in a manner different from that so specified.

    ii. Installation, maintenance, or operation of facilities by Customer, in any way impairing, endangering or otherwise adversely affecting the system of the Authority.

    iii. Objection or prohibition by municipal or any other public authorities, or by property owners, of or to any use of Customer of the rights herein granted.

    iv. The failure of Customer to comply with any of the terms or provision of this Agreement.

    Upon written notice by the Authority to Customer that any of the above listed causes has arisen, Customer shall forthwith remove, at its own expense, all of its facilities from any pole or poles as may be directed in said notice.

11. In the event that the Authority relocates its lines or poles, on which attachments of Customer are located, it shall give prior notice of such intention to Customer and, at Customer's sole expense, Customer may reattach its facilities to the relocated poles under the same conditions in their original locations.

    If the Authority wishes to remove any pole or poles because of discontinuance of use by it of all or part of a line or lines, it shall have the right to do so notwithstanding the use thereof by Customer. Where any such pole or poles are being used by Customer, advance notice of the removal thereof shall be given to Customer. Customer shall have the right to purchase the pole or poles at the higher of the pole's (1) then-value, in-place cost, or (2) net salvage value. Customer will indemnify and save harmless the Authority from any obligation, liability, cost, or charge incurred for the pole after the transfer of title of the pole to Customer. If Customer does not purchase the pole or poles, Customer shall remove its attachments from said pole or poles at its own expense and make any provisions necessary for the operation of its lines in such locations without any responsibility therefore by the Authority.

In either event, should Customer fail to remove its attachments within ninety (90) days after notification, the Authority shall have the right to remove or cause to be removed such attachments at Customer's expense.

12. In cases where sufficient pole space for Customer's attachment is not available on the Authority's poles, Customer will pay the Authority all costs for installing a new pole of sufficient height less the salvage value of the pole replaced but including the cost of removal of the replaced pole.

13. In the event of any termination of the Agreement by either party under the terms of Section 9 hereof, or any termination by the Authority of the use of any pole or poles in accordance with Section 10 hereof, or the relocation or removal of lines or poles under Section 11 hereof, if Customer fails to remove its facilities from any or all of the Authority's poles or systems covered by this Agreement, the Authority shall have the right to remove or cause to be removed the same, and Customer shall pay to the Authority all costs and expenses of any such removal.

14. It is specifically understood by Customer that restoration of service which has been disrupted by any reason whatsoever shall be restored at the Authority's lowest priority level. Where multiple parties are involved in emergency restorations, access to the Authority's poles will be controlled by the Authority.

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed and their corporate seals to be hereunto affixed by their proper officers thereunto duly authorized as of the date hereinabove mentioned.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ____________________________	**BY:** ____________________________
ATTEST:	**(CUSTOMER)**
BY: ____________________________	**BY:** ____________________________

Adopted ______________________, 2015
Effective for bills rendered on and after April 1, 2016

Supersedes: Attachment B, December 1, 2013

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
DISTRIBUTED GENERATION RIDER (RETAIL)
RIDER DG-16

Section 1. Availability:

(A) Service hereunder is available on a first-come, first-served basis to residential and non-residential Customers receiving concurrent retail electric service from the Authority who independently install and operate a distributed generation system to supply a portion of their energy requirements. The total installed capacity of all leased and owned distributed generation facilities shall not exceed two percent of the previous five-year average of the residential and commercial customer class contribution to coincident retail peak demand, after which service under this Rider will no longer be available to new customers. Service hereunder shall be available only upon the approval of the Authority.

Section 2. Applicability:

(A) This Rider is applicable to all residential and non-residential customers in the retail service area of the Authority and shall be limited to Customers receiving concurrent service from the Authority where a photovoltaic or other qualifying generation source of energy as determined by the Authority is installed on the Customer's side of the delivery point, hereinafter the "Customer-Generator", for the Customer's own use, interconnected with and operated in parallel with the Authority's distribution system. Upon a Customer's installation of a qualifying generation source of energy other than a photovoltaic system, the Authority reserves the right to adjust the effective Standby Charge as listed in Section 4(A)(2) as appropriate.

(B) This Rider is only applicable for installed single-phased generation systems that comply with the Authority's then current Standard for Interconnecting Customer-Owned Small Generation hereinafter the "Interconnection Standard", which may be modified by the Authority as deemed necessary. The Nameplate Rating of the Customer's installed generation system and equipment must not exceed the lesser of 20 kW if a residential customer, 1,000 kW if non-residential customer, or the estimated maximum monthly kilowatt (KW) demand. The Customer must comply with the liability insurance requirements of the Interconnection Standard and submit an application to interconnect which must be accepted by the Authority. The Customer agrees to pay an application fee in accordance with the Interconnection Standard and any costs associated with upgrades required to maintain a safe and reliable distribution system.

Section 3. Character of Service:

(A) On an hourly basis, the Authority shall measure the energy delivered to the Customer by the Authority and the energy generated by the Customer-Generator and delivered to the Authority. In each hour, the measured energy generated by the Customer-Generator and delivered to the Authority will be subtracted from measured energy delivered to the customer by the Authority. This calculation will determine the customer's net energy usage. In hours in which the customer's net energy usage is less than zero, the resulting value will be multiplied by the effective Energy Credit as stated in Section 4(A)(3); and in hours in which the Customer's net energy usage is greater than zero, the resulting value will be multiplied by the effective Energy Charge as stated in Section 4(A)(4). To produce a monthly bill, all hourly credits and charges will be summed, and added to other metering, demand, standby charges, and/or applicable taxes and other charges as set forth in the applicable rate schedule or as identified herein. Such a combination of charges and credits may not result in a monthly bill below the monthly Minimum Charge as set forth in Section 4 (C) herein below. Charges or credits will be determined using the appropriate seasonal energy charges and other charges as set forth in Section 4 (A) herein below. If after the Customer's payment of the monthly Minimum Charge a Customer's bill for the month results in a net credit to the Customer, the Authority will issue the credit in the form of a check if it is greater than or equal to $50.00. If the credit is less than $50.00, then it will be applied to the next billing month.

(B) The Authority will furnish, install, own and maintain metering to measure the kilowatt demand delivered by the Authority to the Customer, and to measure the net kilowatt-hours purchased by the Customer or delivered to the Authority. The Authority shall have the right to install special metering and load research devices on the Customer's equipment and the right to use the Customer's telephone line for communication with the Authority's and the Customer's equipment.

(C) If the Customer is not the owner of the premises receiving electric service from the Authority, the Authority shall have the right to require that the owner of the premises give satisfactory written approval of the Customer's request for service under this Rider.

(D) The Authority reserves the right to terminate the Customer's service under this Rider at any time upon written notice to the Customer in the event that the Customer violates any of the terms or conditions of this Rider or the Interconnection Standard, or operates the generation system and equipment in a manner which is detrimental to the Authority or any of its customers.

(E) While receiving service from the Authority under this Rider, the Customer-Generator may retain ownership of any Renewable Energy Credits produced by the Customer-Generator's system. The Authority reserves the right to adjust this Section 3 (E) regarding the ownership of Renewable Energy Credits at its discretion in the future.

(F) Due to the experimental nature of this Rider, the Authority may deem it necessary to re-evaluate this Rider and, as with all schedules, reserves the right to revise, eliminate, or close this Rider to new customers; provided, however, that this Rider shall not be closed prior to December 31, 2020 to any existing Customer receiving service under this Rider.

Section 4. Monthly Rates & Charges:

(A) Basic Monthly Charges:

(1) Metering Charge:
For each month, a charge of ………………………………………………….$9.00

(2) Stand-By Charge:
For each kW of installed capacity, a monthly charge of:
a) Residential …………………………………………………………..$4.70
b) Commerical ………………………………………………………….$5.00

(3) Energy Credits:

All kWh during the Summer Season $0.0389/kWh

All kWh during the Non-Summer Season $0.0381/kWh

Summer Season – The Summer Season energy credit shall apply to all kWh delivered from the Customer-Generator to the Authority for bills rendered during the months of June, July, August and September. Energy credits for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh delivered from the Customer-Generator to the Authority for bills rendered in months other than the Summer Season.

(4) Energy Charges:
As set forth in the applicable rate schedule.

(B) Adjustments to Energy Credits:

The Energy Credits shall be adjusted at least annually to reflect changes in the Authority's determination of its projected cost of energy.

(C) Minimum Charge:

The monthly minimum charge shall be the "Customer Charge" as determined by the applicable rate schedule plus the "Metering Charge" plus any applicable "Stand-By or Demand Charges". Customers taking service under any demand-metered rate schedules shall be exempt from Stand-By Charges.

(D) Taxes:

Amounts for "payments in lieu of taxes", as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fee, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within 15 days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($.50) or two percent (2%) of the amount then outstanding including late payment charges.

Section 6. Terms and Conditions:

Service hereunder is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

Adopted _________, 2015
Effective for bills rendered on and after September 1, 2015

Supersedes:
Schedule RB-14, Effective February 1, 2015 & Rider DG-15

APPENDIX B

2017 RATE SCHEDULES

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL
GENERAL SERVICE
SCHEDULE RG-17

Section 1. Availability:

This schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable for use in private residences, single-family dwelling units, and farms. Energy and power delivered to each residence, dwelling unit, or farm shall be separately metered, and shall include energy used for incidental, non-commercial purposes (e.g., swimming pools, garages, and workshops). This Schedule is not applicable to recognized boarding or rooming houses or commercial establishments. Energy taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $19.50

(2) Energy Charge:

(e) Base Energy Charge:

Summer Season $0.1197/kWh

Non-Summer Season $0.0997/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(f) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and, 0.125 respectively.

(g) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(h) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 6. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _______, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Residential General Service RG-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL
TIME-OF-USE RATE
SCHEDULE RT-17

Section 1. Availability:

Service hereunder is available, on a voluntary basis, as a pilot program, to residential customers in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. The availability of service under this rate schedule shall be limited to the first 300 customers requesting service during the pilot period.

Section 2. Applicability:

This Schedule is applicable to private residences, single family dwelling units, and farms. Energy delivered to each residence, dwelling unit, or farm shall be separately metered, and shall include energy used for incidental, non-commercial purposes (e.g., swimming pools, garages and workshops). This Schedule is not applicable to recognized boarding or rooming houses or commercial establishments. Energy taken under this Schedule may not be resold or shared with others.

"The Authority, at its sole option, may place under this Schedule RT-17 Customers having tankless electric water heaters or other types of loads that are estimated by the Authority to have an annual load factor less than 35%. If at the Authority's option a Customer is placed on this Schedule RT-17 and after twelve consecutive months of service the Customer's annual load factor is greater than or equal to 35%, then the Authority shall remove the Customer from the Schedule RT-17 and credit or debit the Customer's usage for the previous twelve month period for any difference in billing under the Schedule RT-17 and the then applicable residential schedule."

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $28.00

(2) Energy Charge:

(a) Base Energy Charge:

All kWh during the Summer On-Peak Hours $0.3499/kWh

All kWh during the Non-Summer On-Peak Hours $0.3149/kWh

All kWh during Off-Peak Hours $0.0625/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of On-Peak and Off-Peak Hours:

Summer period On-Peak Hours shall mean the hours from 1:00 p.m. to 7:00 p.m., Monday through Friday, for the months of June, July, August, and September, excluding Memorial Day, Independence Day and Labor Day.

Non-Summer period On-Peak Hours shall mean the hours from 6:00 a.m. to 10:00 a.m., Monday through Friday, for the months of December, January, and February, excluding Christmas Day, and New Year Day.

Off-Peak Hours are defined as all hours not specified above as On-Peak hours.

Section 6. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 7. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect, which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule RT-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL TRANSITION ADJUSTMENT
SCHEDULE R-TA-17

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all residential users of energy and power as of April 1, 2016 receiving service pursuant to discontinued RN and RR Rate Schedules which included discounts for residences meeting certain energy efficiency standards. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Limitation of Service:

During the course of a comprehensive review of rates and charges, it was determined that approximately 11,000 active customers are taking service under Rate Schedules RN-13 & RR-13 which have been approved for termination. Beginning April 1, 2016, the Authority will systematically transition existing customers receiving service pursuant to RN-13 and RR-13 to the appropriate Residential General Service Rate Schedule.

The appropriate Residential General Service Rate Schedule will be Schedule RG-16 and its Successor Rate Schedules, or other then appropriate, applicable Residential Rate Schedules. To the extent a customer maintains active service during the transition period, the Transition Adjustment as described in Section 5, (A), (3), will apply. However, should a customer during the transition period terminate service, any new service at that premise shall have the option of the Residential General Service Schedule RG or the Residential Time-of-Use Rate Schedule RT.

The transition period shall consist of a three-year period commencing on April 1, 2016. Applicable credits will be reduced at a rate of 33.33% each year until this Transition Adjustment Schedule R-TA is equal to the then-current Residential General Service Schedule RG.

Section 5. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $19.50

(2) Energy Charge:

(e) Base Energy Charge:

Summer Season $0.1197/kWh

Non-Summer Season $0.0997/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(f) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and, 0.125 respectively.

(g) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(h) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(3) Transition Adjustment:

The charges for Schedule R-TA-17 will be determined by applying the following credits to the charges described in Section 5, (A), (1) and 5, (A), (2).

	R1 Standard Plus		R2 Standard		R3 Standard Plus (Improved)		R4 Standard (Improved)	
	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)
Year 1	$ 8.00	$ 0.0042	$ -	$ 0.0042	$ 5.50	$ 0.0015	$ -	$ 0.0015
Year 2	$ 4.00	$ 0.0021	$ -	$ 0.0021	$ 2.75	$ 0.0008	$ -	$ 0.0008
Year 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 7. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _______, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule R-TA-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE
SCHEDULE GA-17

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power having no more than a 50 kW potential demand in any three months of any twelve consecutive months, for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $25.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1126/kWh

Non-Summer Season $0.0926/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 6. Period of Contract:

The Contract Period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 7. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule GA-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE DEMAND
SCHEDULE GB-17

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge

For each month, a charge of.. $26.00

(2) Demand Charge:

All kW of Billing Demand $23.42/kW

(3) Energy Charges:

(b) Base Energy Charge:

Summer Season $0.0475/kWh

Non-Summer Season $0.0375/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge plus the Demand Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period or (ii) thirty percent (30%) of the greatest Measured Demand computed for the preceding eleven months.

Section 6. Payment:

All bills are due and payable at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill shall be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including late payment charges on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 7. Metering:

Power and energy shall be metered at the point of delivery by the Authority.

Section 8. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule GB-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
SEASONAL GENERAL SERVICE
SCHEDULE GV-17

Section 1. Availability:

This Schedule is available, on a voluntary basis, in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all commercial customers of the Authority meeting the eligibility requirements of the Authority's General Service Demand Rate Schedule, or its successor. Service hereunder applies to all service of the same voltage and character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage of the Authority, and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $26.00

(2) Demand Charge:

All kW of Billing Demand $25.04kW

(3) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.0475/kWh

Non-Summer Season $0.0375/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing

purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the Measured Demand for the current billing period.

Section 6. Payment:

All bills are due and payable at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill shall be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including, late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 7. Metering:

Power and energy shall be metered at the point of delivery by the Authority.

Section 8. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule GV-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE
TIME-OF-USE RATE
SCHEDULE GT-17

Section 1. Availability:

This Schedule is available on a voluntary basis in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability

This Schedule is applicable to all commercial customers of the Authority meeting the eligibility requirements of the Authority's General Service Schedules, or their successor. Service hereunder applies to all service of the same voltage and character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage of the Authority at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $31.00

(2) Demand Charges:

(a) All kW of On-Peak Billing Demand $25.76/kW

(b) All kW of Off-Peak Billing Demand $13.94/kW

(3) Energy Charges:

(a) Base Energy Charge:

All kWh during the Summer On-Peak Hours .... ….$0.0475/kWh

All kWh during the Non-Summer On-Peak Hours $0.0475/kWh

All kWh during Off-Peak Hours $0.0375/kWh

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge plus the Demand Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demands:

The Customer's On-Peak Measured Demand for each monthly billing period shall be the Customer's maximum 30-minute integrated kW demand occurring during the On-Peak Hours of such billing period, as recorded by or determined from suitable measuring devices; provided, however, that during any billing period when the average power factor is less than eighty-five percent (85%), the On-Peak Measured Demand will be adjusted by multiplying such On-Peak Measured Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent for such period.

The Customer's Off-Peak Measured Demand for each monthly billing period shall be the Customer's maximum 30-minute integrated kW demand occurring during the Off-Peak Hours of such billing period, as recorded by or determined from suitable measuring devices; provided, however that during any billing period when the average power factor is less than eighty-five percent (85%), the Off-Peak Measured Demand will be adjusted by multiplying such Off-Peak Measured Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent for such period.

(B) Billing Demands:

The Customer's On-Peak Billing Demand for each monthly billing period shall be the greater of (i) the On-Peak Measured Demand for such period, or (ii) thirty percent (30%) of the greatest On-Peak Measured Demand computed for the preceding eleven months.

The Customer's Off-Peak Billing Demand for each monthly billing period shall be the amount, if any, by which the Customer's Off-Peak Measured Demand for such period exceeds the On-Peak Billing Demand for such period.

Section 6. Determination of On-Peak and Off-Peak Hours:

(A) Summer period On-Peak Hours shall mean the hours from 1:00 p.m. to 7:00 p.m., Monday through Friday, for the months of June, July, August, and September, excluding Memorial Day, Independence Day and Labor Day.

(B) Non-Summer period On-Peak Hours shall mean the hours from 6:00 a.m. to 10:00 a.m., Monday through Friday, for the months of, January, February, March, April, May, October, November, and December, excluding Christmas Day and New Year Day.

(C) The Off-Peak Hours are defined as all hours not specified above as On-Peak Hours.

Section 7. Payment:

All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 8. Period of Contract

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule GT-16, Effective April 1,2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE GENERAL SERVICE
SCHEDULE GL-17

Section 1. Availability:

This Schedule is available on or near the transmission facilities of the Authority to customers in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2: Applicability:

This Schedule is applicable to all customers having more than 300 kW demand in at least three months of any twelve (12) consecutive months and having a rolling twelve month average load factor of at least 70 percent.

Section 3. Character of Service:

Power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed. Energy and power taken under this schedule may not be resold or shared with others.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $26.00

(2) Demand Charge:

Billing Demand

All kW of Billing Demand $23.60/kW

(3) Energy Charges:

(a) Base Energy Charge:

Summer Season $0.0465/kWh
Non-Summer Season $0.0365/kWh

Summer Season - The Summer Season energy charge shall apply to all kWh used during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season - The Non-Summer season energy charge shall apply to all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Credit:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge" plus the "Demand Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Transformation Discount

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the above Firm Demand Charge shall be reduced by $0.60/kW.

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

Section 6. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period, or (ii) thirty percent (30%) of the greatest Measured Demand computed for the preceding eleven months.

Section 7. Payment:

All bills are due and payable in good funds at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased by the larger of one hundred dollars ($100.00), or two percent (2%) of the amount then outstanding including late payment charges. on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 8. Metering

Power and energy shall be metered at the point of delivery by the Authority.

Section 9. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 10. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule GL-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TEMPORARY SERVICE
SCHEDULE TP-17

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to service of a temporary nature for all service of the same available character supplied to the Customer's premises through a single delivery point. For service of a temporary nature and after the initial 12 months of service, the Authority will review each temporary customer and, at its option, may elect to place the service on one of the Authority's other applicable schedules. Service will be provided only after application for service and execution of an agreement with the Authority covering costs of installation and termination of service. Energy taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase as available, at the nominal standard voltage of the Authority as available and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $22.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1412/kWh

Non-Summer Season $0.1212/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Installation and Termination Costs:

The Customer will be required to pay costs of installation and termination of service as calculated by the Authority, the payment for which will be set forth in an agreement executed by the Authority and the Customer. For temporary construction service all such payments shall be in advance, and in no event shall be less than $35.00 per connection.

(D) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payment in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including late charges on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 6. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer and shall be determined by the Authority.

Section 7. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted __________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule TP-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TRANSITION ADJUSTMENT
SCHEDULE TA-17

Section 1. Availability:

This Schedule is available, on a voluntary basis, in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power as of December 1, 2013 receiving service pursuant to General Service Rate Schedule GA or Temporary Service Schedule TP, and who do not qualify for such service, for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Limitation of Service:

During the course of a review of customer billing records, it was determined that approximately 100 customers did not comply with the applicability requirements for Schedule GA-09 (General Service) or its successor schedules. Effective December 1, 2012, the Authority began systematically transitioning customers receiving service pursuant to GA-09, and who previously received or would have received power pursuant to GC-96, to the appropriate General Service Rate Schedule.

This transition adjustment rate schedule was also made available to ball park lighting customers who did not comply with the applicability requirements for Temporary Service Schedule TP-12 or its successor schedules. Effective February 1, 2014, the Authority began systematically transitioning ball park lighting customers receiving service pursuant to TP-12, or who received or would have received power pursuant to the Temporary Service and Ball Park Lighting Schedule TP-09 rate schedule, to the appropriate General Service Rate Schedule.

The appropriate General Service Rate Schedule will be Schedule GB-17 and its Successor Rate Schedules, or other then appropriate, applicable Rate Schedules. Representatives of the Authority will assist customers to select the appropriate and applicable rate schedule.

To the extent a customer selects to transition to General Service Rate Schedule GB-17 or its Successor Rate Schedules, the following transition adjustment will apply. However, should a customer during the transition period terminate service, no transition adjustment shall apply.

As a result of transitioning a customer to the proper rate schedule, customers selecting General Service Rate Schedule GB-17 will be billed commencing on the date upon which the customer receives service under the new rate schedule herein.

Section 5. Basic Monthly Charges:

For each month, at the amount set forth in the appropriate Schedule.

(1) Customer Charge:…………………………………………………………………..$26.00

(9) Summer Energy Charges:…………………………………………………………$0.0700/kWh
Non-Summer Energy Charges………………………………………………….$0.0600/kWh

All kWh at the amounts set forth in the appropriate Schedule.

(c) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(e) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(10) Demand Charge:……………………………………………………………………$12.65/kW

All kW at the amount set forth in the appropriate Schedule.

(11) Transition Adjustment:

The non-summer energy charge for Schedule TA-17 will be determined by multiplying the energy charge in Schedule GB-17 or its Successor Rate Schedules by the following percentages in the appropriate year:

Apr.1			Adjustment
2017	Year	6	As Stated
2018	Year	7	145.00%
2019	Year	8	130.00%
2020	Year	9	115.00%
2021	Year	10	100.00%

The summer energy charge for Schedule TA-17 will be determined by computing the difference between the summer and non-summer energy charge in Schedule GB-17 or its Successor Rate Schedules. This amount shall be added to the currently applicable TA-17

non-summer energy charge during the months specified in Schedule GB-17 or its Successor Rate Schedules.

The demand charge for Schedule TA-17 will be determined by multiplying the demand charge in Schedule GB-17 or its Successor Rate Schedules by the following percentages in the appropriate year:

Apr. 1			Adjustment
2017	Year	6	As Stated
2018	Year	7	65.50%
2019	Year	8	77.00%
2020	Year	9	88.50%
2021	Year	10	100.00%

The ratios and charges set forth in this Transition Adjustment are subject to change if and when the Authority revises its rates and charges. All other provisions and Sections of the selected, applicable General Service Rate Schedule shall apply.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule TA-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TRAFFIC SIGNAL SERVICE
SCHEDULE TL-17

Section 1. Availability:

This Schedule is available to all cities, towns, communities, and the State Highway Department located in the service area of the Authority.

Section 2. Applicability:

This Schedule is applicable for the operation of traffic signals located in the Authority's service area where the Authority has an existing secondary distribution line. Energy taken under this Schedule may not be resold or shared with other operations.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single-phase at 120 volts nominal.

Section 4. Installation:

The Authority will make its connection to the Customer's service wire on the Authority's nearest pole carrying 120/240 volt secondary. The Customer must furnish, install and maintain all service wires, fixtures and other equipment required for operation of the traffic signal installation.

Section 5. Monthly Billing Rate:

(A) Basic Monthly Charges:

(1) Metered Service:

(f) Customer Charge:

For each month, a charge of $25.00

(g) Base Energy Charge:

All kWh $0.1010/kWh

(12) Unmetered Service:

Base Energy Charge:

For each lamp using 25 watts or less ....$1.60 per lamp

For each lamp using 26 to 70 watts.................................……..$2.21 per lamp

For each lamp using more than 70 watts .... $3.00 per lamp

(13) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to \$0.03641/kWh and 0.125, respectively.

(14) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(15) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge shall be the same as the monthly charges set forth herein above; provided, however, that if separate bills are required for each installation, the minimum bill shall be \$5.00 per installation.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payment in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Determination of Energy Usage for Unmetered Service:

For purposes of applying the aforementioned Fuel Adjustment Clause and Demand Sales Adjustment Clause, the monthly kWh usage for service provided hereunder shall be as follows:

For each lamp using 25 watts or less……. ....5 kWh

For each lamp using 26 to 70 watts ....22 kWh

For each lamp using more than 70 watts..44 kWh

Section 7. Billing and Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents (\$0.50) or two percent (2%) of the amount then outstanding including late payment charges.

Section 8. Period of Contract:

The contract period shall be one (1) year or longer at the Authority's option.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule TL-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING
SCHEDULE MS-17

Section 1. Availability:

This Schedule is available to all cities, towns, communities, and the State Highway Department located in the service area of the Authority.

Section 2. Applicability:

This Schedule is applicable for municipal series and multiple circuit street, highway and bridge lighting within and immediately adjacent to city, town and community limits. Energy taken under this Schedule may not be resold or shared with other operations.

Section 3. Character of Service:

Energy delivered hereunder shall be alternating current, 60 Hertz, at a nominal standard voltage of the Authority, as available. Lamps may be connected in series or in multiple circuits, at the Authority's option.

Section 4. Installation:

The Authority will provide all labor and equipment necessary for installation including lamps and glassware. If the Authority is requested to provide a steel standard for the mounting of a light, the Customer will provide mixed concrete in the amount required for the standard. The Authority will provide the necessary forms and labor for the concrete work.

All equipment and other equipment installed by the Authority shall remain the property of the Authority.

Section 5. Monthly Rates and Charges:

The monthly charges hereunder shall consist of the following charges:

(A) Base Monthly Charges:

(1) Fixtures and Standards:

There shall be a monthly charge for each fixture and standard provided by the Authority, based on the type and characteristics thereof, determined in accordance with Exhibits A and B hereto, which such Exhibits A and B may be amended by the Authority from time to time to reflect the types of fixtures and standards the Authority will make available. In addition, the Authority may, at its sole option, provide on a work-order basis, fixtures and standards not provided for in Exhibits A and B if the Customer agrees to pay the Authority's cost of providing and installing such standards and fixtures.

(2) Energy Charges:

(a) Base Energy Charge:

All kWh ....$0.0661/kWh.

(b) Fuel Adjustment Charge:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The monthly charge shall be the total of the charges specified hereinabove.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Determination of Energy Usage

To determine the Customer's energy usage at service connection, the Authority, at its option, may either (i) meter such energy usage, or (ii) estimate the monthly energy usage of such service based on the characteristics and mode of operation of the lamps and other equipment served therefrom.

Section 7. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges.

Section 8. Period of Contract:

The contract period shall be one (1) year or longer at the Authority's option.

<u>Section 9. Terms and Conditions</u>:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule MS-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE MS-17

Exhibit A
Schedule of Available Poles and Arms

	Available Pole and Arm Type	Monthly Charge
1	Wood standard, 30'	$ 4.58
2	Wood, 35'	$ 5.25
3	Wood. 40'	$ 6.19
4	Fiberglass, Round, Black, 18'	$ 5.66
5	Fiberglass, Round, Brown, 20'	$ 5.84
6	Fiberglass, Round, 30'	$ 13.19
7	Fiberglass, Round, 40'	$ 13.30
8	Aluminum Standard, 25'	$ 12.09
9	Aluminum, Round, 35'	$ 20.70
10	Fiberglass, Round, 30' Breakaway DOT	$ 18.77
11	Light Pole, $301-$400	$ 10.17
12	Light Pole, $401-$500	$ 11.72
13	Light Pole, $501-$600	$ 13.22
14	Light Pole, $601-$700	$ 14.77
15	Light Pole, $701-$900	$ 17.04
16	Light Pole, $901-$1100	$ 20.07
17	Light Pole, $1101-$1300	$ 22.30
18	Light Pole, $1301-$1500	$ 24.50
19	Light Pole, $1501-$1700	$ 26.70
20	Light Pole, $1701-$1900	$ 28.90
21	Light Pole, $1901-$2100	$ 31.10
22	Light Pole, $2101-$2300	$ 33.30
23	Light Pole, $2301-$2500	$ 35.50
24	Light Pole Arm, $201-$400	$ 6.22
25	Light Pole Arm, $401-$600	$ 9.69
26	Light Pole Arm, $601-$800	$ 12.60
27	Light Pole Arm, $801-$1000	$ 15.40

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE MS-17

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
1	100 Watt, HPS, Private	41	$ 5.39
2	150 Watt, HPS, Private	61	$ 6.76
3	150 Watt, HPS, Traditional	61	$ 8.40
4	150 Watt, HPS, Roadway	61	$ 7.74
5	150 Watt, HPS, Modern (Shoebox)	61	$ 11.64
6	250 Watt, HPS, Roadway	103	$ 10.73
7	250 Watt, HPS, Shoebox	103	$ 14.85
8	400 Watt, HPS, Flood Light	164	$ 15.80
9	400 Watt, HPS, Roadway	164	$ 15.06
10	400 Watt, HPS, Shoebox	164	$ 19.40
11	400 Watt, MH, Flood Light	164	$ 16.74
12	400 Watt, MH, Galleria	164	$ 18.55
13	1000 Watt, MH, Flood Light	410	$ 33.92
14	1000 Watt, MH, Galleria	410	$ 36.06
15	$301-$400, 70 Watt, MH	29	$ 12.22
16	$301-$400, 175 Watt, MH	73	$ 15.13
17	$301-$400, 150 Watt, HPS	61	$ 14.44
18	$401-$500, 70 Watt MH	29	$ 13.62
19	$401-$500, 175 Watt MH	73	$ 16.53
20	$401-$500, 150 Watt HPS	61	$ 16.11
21	$401-$500, 250 Watt MH	103	$ 18.51
22	$401-$500, 250 Watt HPS	103	$ 18.89
23	$401-$500, 400 Watt MH	164	$ 22.54
24	$401-$500, 400 Watt HPS	164	$ 22.92
25	$401-$500, 1000 Watt MH	410	$ 38.80
26	$401-$500, 1000 Watt HPS	410	$ 39.18
27	$501-$600, 70 Watt MH	29	$ 15.02
28	$501-$600, 175 Watt MH	73	$ 17.93
29	$501-$600, 150 Watt HPS	61	$ 17.73
30	$501-$600, 250 Watt MH	103	$ 19.91
31	$501-$600, 250 Watt HPS	103	$ 20.51
32	$501-$600, 400 Watt MH	164	$ 23.94
33	$501-$600, 400 Watt HPS	164	$ 24.54
34	$501-$600, 1000 Watt MH	410	$ 40.20
35	$501-$600, 1000 Watt HPS	410	$ 40.80
36	$601-$700, 70 Watt MH	29	$ 16.42
37	$601-$700, 175 Watt MH	73	$ 19.33
38	$601-$700, 150 Watt HPS	61	$ 19.13
39	$601-$700, 250 Watt MH	103	$ 21.31

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
40	$601-$700, 250 Watt HPS	103	$ 21.91
41	$601-$700, 400 Watt MH	164	$ 25.34
42	$601-$700, 400 Watt HPS	164	$ 25.94
43	$601-$700, 1000 Watt MH	410	$ 41.60
44	$601-$700, 1000 Watt HPS	410	$ 42.20
45	$701-$800 175 Watt, MH	73	$ 20.73
46	$701-$800 150 Watt, HPS	61	$ 20.53
47	$701-$800 250 Watt, MH	103	$ 22.71
48	$701-$800 250 Watt, HPS	103	$ 23.31
49	$701-$800 400 Watt, MH	164	$ 26.74
50	$701-$800 400 Watt, HPS	164	$ 27.34
51	$701-$800 1000 Watt, MH	410	$ 43.00
52	$701-$800 1000 Watt, HPS	410	$ 43.60
53	$801-$900 175 Watt, MH	73	$ 22.13
54	$801-$900 150 Watt, HPS	61	$ 21.93
55	$801-$900 250 Watt, MH	103	$ 24.11
56	$801-$900 250 Watt, HPS	103	$ 24.71
57	$801-$900 400 Watt, MH	164	$ 28.14
58	$801-$900 400 Watt, HPS	164	$ 28.74
59	$801-$900 1000 Watt, MH	410	$ 44.40
60	$801-$900 1000 Watt, HPS	410	$ 45.00
61	$901-$1000 175 Watt, MH	73	$ 23.53
62	$901-$1000 150 Watt, HPS	61	$ 23.33
63	$901-$1000 250 Watt, MH	103	$ 25.51
64	$901-$1000 250 Watt, HPS	103	$ 26.11
65	$901-$1000 400 Watt, MH	164	$ 29.54
66	$901-$1000 400 Watt, HPS	164	$ 30.14
67	$901-$1000 1000 Watt, MH	410	$ 45.80
68	$901-$1000 1000 Watt, HPS	410	$ 46.40
69	Vandal Shield (1)	-	$ 1.90
	Experimental Fixtures (Energy Not Included in Monthly Rental Charge)		
70	$101-$300 Range, LED (3)	Varies by Fixture	*$6.20*
71	$301-$500 Range, LED (3)	Varies by Fixture	*$8.41*
72	$501-$700 Range, LED (3)	Varies by Fixture	*$10.61*
73	$701-$900 Range, LED (3)	Varies by Fixture	*$12.82*
74	$901-$1100 Range, LED (3)	Varies by Fixture	*$15.03*
75	$1101-$1300 Range, LED (3)	Varies by Fixture	*$17.23*
76	$1301-$1500 Range, LED (3)	Varies by Fixture	*$19.44*

Note 1: Vandal Shields may be required for fixtures receiving damage more than once during any consecutive three year period.

Note 2: All monthly rental charges include energy charges unless otherwise specified.

Note 3: Experimental fixtures do not include energy charges. Energy charges will vary based on specific fixture energy requirements and will be in addition to the stated rental charges.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-17

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable for outdoor yard and area lighting to retail customers where the Authority installs and furnishes the lighting equipment including lamps, fixtures, and the necessary lighting circuits and fittings. The monthly facilities and energy charges set forth in Section 4 are applicable only to lighting fixtures located so as to be furnished energy by existing facilities, poles and transformers on existing poles, or through the addition of not more than one (1) wood pole for attachment of each lighting fixture. Where extension of primary lines or special facilities or more than one (1) new pole per lighting fixture is required, the cost of constructing such additional facilities shall be repaid by the customer requesting service. Energy purchased under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

The Authority shall provide the outdoor yard and area lighting service hereunder including providing, installing, and maintaining the necessary facilities such as requisite poles and light fixtures on a contractual basis. Upon request for service, the Authority will require the execution of an agreement between the customer and the Authority (the "Outdoor Rental Lighting Agreement"). Energy delivered hereunder shall be alternating current 60 Hertz at the nominal standard voltage of the Authority, as available.

Section 4. Monthly Rates and Charges:

The monthly charges hereunder shall include the following charges:

(A) Basic Monthly Charges:

(1) Pole and Fixture Rental Fees:

There shall be a monthly charge for each pole and fixture furnished by the Authority, based on the type and characteristics thereof, determined in accordance with Exhibits A and B hereto. Such Exhibits A and B may be amended by the Authority from time to time to reflect the standard types of poles and fixtures the Authority will make available.

(2) Energy Charges:

(a) Base Energy Charge:

For each fixture, there shall be a base energy charge of $0.0661/kWh for all kWh of energy use.

(b) Fuel Adjustment Charge:

The Authority's Fuel Adjustment Clause FAC-17 is applicable to all energy sales hereunder, with "F/S" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(h) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-17 is applicable to all energy sales hereunder.

(g) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Additional Facilities Charge:

The Basic Monthly Charges herein apply only to fixtures located so as to be furnished energy by existing facilities, poles and transformers on existing poles, and/or through the addition of not more than one pole for the attachment of each lighting fixture. Additional facilities, including the extension of primary lines, or special facilities, or more than one (1) new pole per lighting fixture, will be furnished by the Authority where the customer agrees to pay the cost of constructing such additional facilities.

(C) Minimum Charge:

The minimum charge shall be the same as the monthly charges set forth in Sections 4.A. and 4.B. hereinabove.

(D) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the customer has furnished the Authority evidence of specific exemption secured by the customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Energy Usage:

The Authority, at its option, may meter the monthly kWh energy usage of light fixtures provided hereunder. Otherwise, each unmetered fixture shall be deemed to use the estimated average monthly kWh energy set forth in the currently effective Exhibit B hereto.

Section 6. Payment:

(A) Bills for service hereunder shall become part of and shall be added to the customer's monthly account for metered electric service.

(B) Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. When the outdoor light is the only account with the Authority and payment of the bill is not received by said due date, the amount of the bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($0.50) or two percent (2%) of (i) the amount calculated under Section 4 of this Schedule or (ii) the total amount then outstanding including late payment charges. If the outdoor light is billed in conjunction with another account and payment of the bills is not received by said due date, then the total bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter by the larger of fifty cents ($0.50) or two percent (2%) of (i) the total amount calculated under this Schedule or (ii) the total bill then outstanding

including late payment charges.
Section 7. Period of Contract:

The Outdoor Rental Lighting Agreement shall become effective on the date the lighting fixtures are first installed and operated and shall remain in effect for a period of three (3) years and thereafter until terminated by either party giving to the other thirty (30) days notice. In the event that the customer transfers, terminates or, for any reason, discontinues outdoor yard and area lighting service and/or electric service to the property on which the rental lighting is installed, the following charges shall become due and payable and may be paid in whole or in part by any deposit for electric service that the customer may have made:

> The greater of (i) the sum of the monthly charges for all remaining months of the effective terms of the Outdoor Rental Lighting Agreement, or (ii) fifty dollars ($50.00) for each fixture mounted on existing facilities, or (iii) one hundred fifty dollars ($150.00) for each fixture and pole that is caused to be removed due to termination of the Outdoor Rental Lighting Agreement.

In the event the customer wishes to terminate the private outdoor lighting service due to the sale, lease, or rental to others of the property on which lights are installed and the new party wishes to continue the rental agreement, the Authority shall release the customer from the termination charges provided for herein at such time that the new customer makes application for electric service and signs and Outdoor Rental Lighting Agreement for the remaining months of the original agreement.

Section 8. Limitations of Service:

(A) The Authority assumes the responsibility for ordinary maintenance of poles, equipment and lamps with all maintenance work to be performed during normal working hours at the discretion of the Authority.

(B) The Authority shall use reasonable diligence to provide a constant service to the lighting fixtures, but if such service or equipment shall fail or be interrupted, or become defective through acts of nature, or public enemies or by accident, strikes, labor troubles or by actions of the elements, or for any cause beyond its reasonable control, the Authority shall not be liable therefore.

(C) The Customer shall assume responsibility of providing reasonable protection to the lighting installation from accidental collision by motor vehicle and other similar equipment and shall further assume responsibility of providing the installation protection against vandalism.

(D) The Authority reserves the right to terminate private outdoor lighting service immediately upon the threat of damage or continued damage to the installed equipment.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect and the "Outdoor Rental Lighting Agreement" executed between the customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule OL-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-17

Exhibit A
Schedule of Available Poles and Arms

	Available Pole and Arm Type	Monthly Charge
1	Wood standard, 30'	$ 4.58
2	Wood, 35'	$ 5.25
3	Wood. 40'	$ 6.19
4	Fiberglass, Round, Black, 18'	$ 5.66
5	Fiberglass, Round, Brown, 20'	$ 5.84
6	Fiberglass, Round, 30'	$ 13.19
7	Fiberglass, Round, 40'	$ 13.30
8	Aluminum Standard, 25'	$ 12.09
9	Aluminum, Round, 35'	$ 20.70
10	Fiberglass, Round, 30' Breakaway DOT	$ 18.77
11	Light Pole, $301-$400	$ 10.17
12	Light Pole, $401-$500	$ 11.72
13	Light Pole, $501-$600	$ 13.22
14	Light Pole, $601-$700	$ 14.77
15	Light Pole, $701-$900	$ 17.04
16	Light Pole, $901-$1100	$ 20.07
17	Light Pole, $1101-$1300	$ 22.30
18	Light Pole, $1301-$1500	$ 24.50
19	Light Pole, $1501-$1700	$ 26.70
20	Light Pole, $1701-$1900	$ 28.90
21	Light Pole, $1901-$2100	$ 31.10
22	Light Pole, $2101-$2300	$ 33.30
23	Light Pole, $2301-$2500	$ 35.50
24	Light Pole Arm, $201-$400	$ 6.22
25	Light Pole Arm, $401-$600	$ 9.69
26	Light Pole Arm, $601-$800	$ 12.60
27	Light Pole Arm, $801-$1000	$ 15.40

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-17

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
1	100 Watt, HPS, Private	41	$ 5.39
2	150 Watt, HPS, Private	61	$ 6.76
3	150 Watt, HPS, Traditional	61	$ 8.40
4	150 Watt, HPS, Roadway	61	$ 7.74
5	150 Watt, HPS, Modern (Shoebox)	61	$ 11.64
6	250 Watt, HPS, Roadway	103	$ 10.73
7	250 Watt, HPS, Shoebox	103	$ 14.85
8	400 Watt, HPS, Flood Light	164	$ 15.80
9	400 Watt, HPS, Roadway	164	$ 15.06
10	400 Watt, HPS, Shoebox	164	$ 19.40
11	400 Watt, MH, Flood Light	164	$ 16.74
12	400 Watt, MH, Galleria	164	$ 18.55
13	1000 Watt, MH, Flood Light	410	$ 33.92
14	1000 Watt, MH, Galleria	410	$ 36.06
15	$301-$400, 70 Watt, MH	29	$ 12.22
16	$301-$400, 175 Watt, MH	73	$ 15.13
17	$301-$400, 150 Watt, HPS	61	$ 14.44
18	$401-$500, 70 Watt MH	29	$ 13.62
19	$401-$500, 175 Watt MH	73	$ 16.53
20	$401-$500, 150 Watt HPS	61	$ 16.11
21	$401-$500, 250 Watt MH	103	$ 18.51
22	$401-$500, 250 Watt HPS	103	$ 18.89
23	$401-$500, 400 Watt MH	164	$ 22.54
24	$401-$500, 400 Watt HPS	164	$ 22.92
25	$401-$500, 1000 Watt MH	410	$ 38.80
26	$401-$500, 1000 Watt HPS	410	$ 39.18
27	$501-$600, 70 Watt MH	29	$ 15.02
28	$501-$600, 175 Watt MH	73	$ 17.93
29	$501-$600, 150 Watt HPS	61	$ 17.73
30	$501-$600, 250 Watt MH	103	$ 19.91
31	$501-$600, 250 Watt HPS	103	$ 20.51
32	$501-$600, 400 Watt MH	164	$ 23.94
33	$501-$600, 400 Watt HPS	164	$ 24.54
34	$501-$600, 1000 Watt MH	410	$ 40.20
35	$501-$600, 1000 Watt HPS	410	$ 40.80
36	$601-$700, 70 Watt MH	29	$ 16.42
37	$601-$700, 175 Watt MH	73	$ 19.33
38	$601-$700, 150 Watt HPS	61	$ 19.13
39	$601-$700, 250 Watt MH	103	$ 21.31

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
40	$601-$700, 250 Watt HPS	103	$ 21.91
41	$601-$700, 400 Watt MH	164	$ 25.34
42	$601-$700, 400 Watt HPS	164	$ 25.94
43	$601-$700, 1000 Watt MH	410	$ 41.60
44	$601-$700, 1000 Watt HPS	410	$ 42.20
45	$701-$800 175 Watt, MH	73	$ 20.73
46	$701-$800 150 Watt, HPS	61	$ 20.53
47	$701-$800 250 Watt, MH	103	$ 22.71
48	$701-$800 250 Watt, HPS	103	$ 23.31
49	$701-$800 400 Watt, MH	164	$ 26.74
50	$701-$800 400 Watt, HPS	164	$ 27.34
51	$701-$800 1000 Watt, MH	410	$ 43.00
52	$701-$800 1000 Watt, HPS	410	$ 43.60
53	$801-$900 175 Watt, MH	73	$ 22.13
54	$801-$900 150 Watt, HPS	61	$ 21.93
55	$801-$900 250 Watt, MH	103	$ 24.11
56	$801-$900 250 Watt, HPS	103	$ 24.71
57	$801-$900 400 Watt, MH	164	$ 28.14
58	$801-$900 400 Watt, HPS	164	$ 28.74
59	$801-$900 1000 Watt, MH	410	$ 44.40
60	$801-$900 1000 Watt, HPS	410	$ 45.00
61	$901-$1000 175 Watt, MH	73	$ 23.53
62	$901-$1000 150 Watt, HPS	61	$ 23.33
63	$901-$1000 250 Watt, MH	103	$ 25.51
64	$901-$1000 250 Watt, HPS	103	$ 26.11
65	$901-$1000 400 Watt, MH	164	$ 29.54
66	$901-$1000 400 Watt, HPS	164	$ 30.14
67	$901-$1000 1000 Watt, MH	410	$ 45.80
68	$901-$1000 1000 Watt, HPS	410	$ 46.40
69	Vandal Shield (1)	-	$ 1.90
	Experimental Fixtures (Energy Not Included in Monthly Rental Charge)		
70	$101-$300 Range, LED (3)	Varies by Fixture	*$ 6.20*
71	$301-$500 Range, LED (3)	Varies by Fixture	*$ 8.41*
72	$501-$700 Range, LED (3)	Varies by Fixture	*$ 10.61*
73	$701-$900 Range, LED (3)	Varies by Fixture	*$ 12.82*
74	$901-$1100 Range, LED (3)	Varies by Fixture	*$ 15.03*
75	$1101-$1300 Range, LED (3)	Varies by Fixture	*$ 17.23*
76	$1301-$1500 Range, LED (3)	Varies by Fixture	*$ 19.44*

Note 1: Vandal Shields may be required for fixtures receiving damage more than once during any consecutive three year period.

Note 2: All monthly rental charges include energy charges unless otherwise specified.

Note 3: Experimental fixtures do not include energy charges. Energy charges will vary based on specific fixture energy requirements and will be in addition to the stated rental charges.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL LIGHT AND POWER
SCHEDULE ML-17

Section 1. Availability:

(D) Service hereunder is available at Delivery Points on or near the transmission facilities of the Authority to municipal, sales-for-resale customers having a contract demand of 1,000 kilowatts or more.

(E) This Rate Schedule is not available for breakdown, standby, supplementary, or auxiliary service, and service hereunder shall not be used in parallel with other sources of electric power.

(F) Prior to the provision of service hereunder at one or more Delivery Points, the Customer shall have entered into a Service Agreement, mutually agreeable to the Customer and the Authority, that shall set forth general terms and conditions of service hereunder.

Section 2. Character of Service:

(B) Electric power and energy delivered hereunder shall be unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, at one of the Authority's standard nominal voltages of 480 volts or higher. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed. Only one transformation will be provided hereunder from the available transmission voltage.

Section 3. Monthly Rates and Charges:

(A) Charges for Power Service:

(1) Monthly Customer Charge:

A monthly charge for each Delivery Point of $1,500.00

(2) Monthly Demand Charge:

(a) Base Demand Charge:

For the first 1,000kW or less of Billing Demand........................ $17,380.00

All Additional kW of Billing Demand $17.38

(b) Transformation Discount:

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the foregoing Base Monthly Demand Charge shall be reduced by $0.60/kW.

(c) Excess Demand Charge:

For each kW of the Customer's Measured Demand that is classified as Excess Demand, a charge, in addition to the Base Demand Charge, of $11.00/kW.

(i) Demand Sales Adjustment:

For each kW of Billing Demand, a credit or change, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment DSC-17, or its currently applicable successor clause, if any.

(j) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any.

(3) <u>Energy Charge:</u>

(a) Base Energy Charge:

All kWh $0.0416/kWh

(d) Fuel Adjustment Clause:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-17, or its currently applicable successor clause, if any, with "Fb/Sb" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(2) <u>Excess Reactive Demand Charge:</u>

Each kVAr of Excess Reactive Demand $0.82/kVAr

(C) <u>Monthly Facilities Charges:</u>

In the event service to the Customer requires the Authority to provide facilities in addition to, or different from, facilities normally provided by the Authority, and the Authority provides such facilities, the Customer also shall pay the Authority a Monthly Facilities Charge, in addition to all other charges hereunder. Such Monthly Facilities Charge shall be equal to 1.4% of the original installed cost of such facilities.

(D) Minimum Monthly Bill:

The minimum monthly bill shall consist of the sum of the Monthly Customer Charge, the Monthly Demand Charge, and the Monthly Facilities Charge, if any.

(D) Taxes and Other Assessments:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the foregoing monthly rates and charges. The total monthly billing amount hereunder also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Determination of Demands:

(B) Billing Demand:

(1) The Billing Demand for each Billing Month shall be the greater of (i) the Customer's Measured Demand for such Billing Month or (ii) eighty percent (80%) of the Contract Demand for such Billing Month.

(2) In the event that, during any Billing Month, the provision of service by the Authority hereunder is interrupted for a period of four (4) or more consecutive hours as a result of an occurrence of one of the circumstances set forth in Section 6(A) hereof, the Billing Demand for such Billing Month will be reduced by the proportion which the number of hours of such interruption bears to the total number of hours in the Billing Month.

(B) Measured Demand:

The Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the customer during such Billing Month; provided, however, that if the Customer's load is unbalanced between phases by more than ten percent (10%), the Authority, at its sole option, may (i) require the Customer, at the Customer's expense, to make the changes necessary to correct such condition, and/or (ii) assume that the load on each phase is equal to the greatest load on any phase.

(C) Contract Demand:

(1) Except as otherwise provided herein, the Contract Demand applicable to each Delivery Point during each Billing Month shall be the maximum amount of power, in kilowatts, that the Customer shall have requested and the Authority shall have agreed to supply during such Billing Month, as evidenced in the Service Agreement between the Customer and the Authority. During the first twelve (12) months of service to a new Delivery Point, the Authority, at its sole option, may agree to adjust the Customer's Contract Demand on a month-to-month basis and/or to forego the application of Section 4 (D) hereinbelow, in order to allow the Customer and the Authority an adequate build-up or phase-in of operations; provided, however, that the Authority reserves the right to condition such agreement on such additional terms and conditions as the Authority deems appropriate for the circumstances.

(2) Except as otherwise provided herein or in the Service Agreement between the Customer and the Authority, the Customer may reduce its Contract demand for a Delivery Point, or any twelve month period and subsequent twelve month periods, to not less than 1,000 kW by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first Period to which the notice applies, provided, however, that (i) no such reduction shall become effective before the fifth anniversary of service to the Delivery point, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Contract Demand for such year.

(e) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Contract Demand(s) for such years.

Notices of such reductions in the Customer’s Contract Demand shall be irrevocable once given.

(3) The Customer’s Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rate Schedule, or (ii) by mutual agreement between the Authority and the Customer. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request by the Customer. In such an event, the Authority may require additional, special terms and conditions applicable to service to the Customer.

(D) Excess Demand:

(1) The Customer’s Excess Demand for each Billing Month shall be that portion of the Customer’s Measured Demand for such Billing Month that exceeds 110% of the Customer’s then current Contract Demand hereunder.

(2) Notwithstanding the foregoing or any other provision of this Rate Schedule to the contrary, in the event that (i) the Customer’s rate or use of electricity at a Delivery Point exceeds the Customer’s then current Contract Demand hereunder, and (ii) the Customer fails to comply promptly with a request by the Authority to reduce such rate of use so as not to exceed such aggregate Contract Demand, the Customer’s Contract Demand(s) for such Delivery Point for the current and subsequent Billing Months, shall at the Authority’s sole option, be increased, from what it otherwise would have been, by the amount of such excess. In addition, in such event, the Customer shall be liable for any damage to the Authority’s facilities caused by such excess.

(3) Notwithstanding the foregoing or any other provision of this Rate Schedule, the Authority shall be under no obligation whatsoever to supply demands in excess of the Customer’s Contract Demand, and nothing herein shall be construed as restricting the right of the Authority to take such steps as

the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed the Customer's Contract Demand.

(E) Excess Reactive Demand:

The Customer's Excess Reactive Demand for each Billing Month shall be the amount, if any, by which the Customer's maximum 30-minute integrated reactive demand, in kilovars (kVAr) during such Billing Month exceeds 48.5% of the Customer's Measured Demand, in kilowatts (kW), for such Billing Month.

Section 5. Billing:

All bills are due and payable at the offices of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased by the greater of (i) one hundred dollars ($100.00), or (ii) two percent (2%) of the amount then outstanding including late payment charges. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of the service shall not relieve the Customer of any liability for the Agreed Minimum Bill(s) for the period(s) of time service is so discontinued.

Section 6. Interruption of Service:

(A) The Authority will make reasonable provisions to ensure satisfactory and continuous service but does not guarantee a continuous supply of electrical energy and shall not be liable for damage occasioned by interruptions of service or failure to commence delivery caused by an act of God, or the public enemy, or for any cause reasonably beyond the Authority's control, including, but not limited to, the failure or breakdown of generating or transmitting facilities, floods, fire, strikes or action or order of any agency having jurisdiction over the premises, or for interruptions that the Authority deems necessary for the inspection of, repair to, or changes to the Authority's facilities.

(B) Nothing herein shall be construed as restricting in any way the Authority's right to interrupt service to the Customer as the Authority may deem necessary or appropriate to facilitate inspection of, repair to, or changes to the Authority's facilities consistent with prudent utility practice; provided, however, that the Authority shall use its reasonable best efforts, when practicable, to provide the Customer with advance notice of such interruptions and to coordinate with the Customer the times of such interruptions. In any event, failure of the Authority and the Customer to agree upon the time of such an interruption shall not restrict the Authority from proceeding therewith as the Authority deems necessary.

(C) The Customer shall provide written notification to the authority immediately of any defects, trouble or accident which may in any way affect the delivery of power by the Authority to the Customer.

(D) Notwithstanding any provisions of this Rate Schedule to the contrary, the Customer shall not be liable for any charges hereunder for any period during which he is unable to accept electric service due to strikes, fire, floods, or act of God or the public enemy.

(E) Both the Customer and the Authority shall use all due diligence in removing any causes which prevent the delivery or use of electrical power and energy hereunder.

(F) Any claims against the Authority resulting from an interruption of service shall be governed by the terms, conditions and limitations of the South Carolina Tort Claims Act, and any recovery in such claim shall not include indirect or consequential damages.

Section 7. Indemnity:

All electrical power and energy provided for hereunder shall be the property of the Customer upon passing the Delivery Point(s) and the Customer shall have sole responsibility for the use, misuse or presence of said power and energy on the Customer's side of the Delivery Point(s). The Customer will indemnify and hold the Authority harmless from al claims, loss or expense arising from, or in any way connected with, the presence, use of misuse of electrical power and energy on the Customer's side of the Delivery Point(s).

Section 8. Additional Terms and Conditions:

Service under this Rate Schedule is subject to the then currently effective Service Agreement between the Customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for service rendered on or after April 1, 2017

Supersedes:
Schedule ML-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
SCHEDULE L-17

Section 1. Availability:

(A) Service hereunder is available at Delivery Points on or near the transmission facilities of the Authority at which the Customer has a potential demand for electric service of at least 1,000 kW; provided, however, that service hereunder shall not be available for service to large, highly fluctuating or otherwise unusual loads without the agreement of the Authority.

(B) Subject to the terms of this Rate Schedule and the General Terms and Conditions of Large Power Electric Service (hereinafter, "General Terms and Conditions") attached hereto as Attachment A and made a part hereof, service hereunder is available, at individual Delivery Points each satisfying the requirements of the foregoing paragraph, to (i) industrial, commercial, and governmental Customers of the Authority, and (ii) municipal and cooperative wholesale Customers of the Authority may offer this service to an industrial, commercial, or governmental customer of such wholesale customer.

(C) Except as may be otherwise provided in the Standby Service Rider L-17-SB, this Rate Schedule is not available for breakdown, standby, supplementary, or auxiliary service, and service hereunder shall not be used in parallel with other sources of electric power. Except with respect to service to municipal and cooperative Customers of the Authority, as provided in the foregoing paragraph, service hereunder shall not be sold for resale or exchange or shared with others.

(D) Prior to the provision of service hereunder at one or more Delivery Points, the Customer shall be required to enter into an Agreement for Large Power Electric Service (hereinafter, "Service Agreement") of the form prescribed in the General Terms and Conditions which may be modified by the Authority from time to time.

Section 2. Character of Service:

(A) Electric power and energy delivered hereunder shall be unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, at one of the Authority's standard nominal voltages of 480 volts or higher. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed. Only one transformation will be provided hereunder from the available transmission voltage.

(B) "Firm Power," as used herein, shall refer to electric power and energy purchased by the Customer hereunder, other than electric power and energy purchased by the Customer pursuant to any other applicable rider or riders hereto.

Section 3. Monthly Rates and Charges:

(A) Monthly Customer Charge:

A monthly charge for each Delivery Point of $3,400.00

(B) Charges for Standard Firm Power Service:

The monthly charges for Firm Power hereunder shall include the following charges:

(1) Monthly Demand Charge:

(a) Base Demand Charge:

For the first 300 kW or less of Firm Billing Demand $7,511.00

All Additional kW of Firm Billing Demand @ $19.26

(c) Transformation Discount:

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the foregoing Base Monthly Demand Charge shall be reduced by $0.60/kW.

(d) Excess Demand Charge:

(iii) For each kW of the Customer's Measured Demand that is classified as Excess On-Peak Demand, a charge, in addition to the Base Demand Charge, of $12.00/kW.

(iv) For each kW of the Customer's Measured Demand that is classified as Excess Off-Peak Demand, a charge equal to the Base Demand Charge.

(e) Excess Reactive Demand Charge:

Each kVAr of Excess Reactive Demand @ $0.82/kVAr

(f) Demand Sales Adjustment:

For each kW of Firm Billing Demand, a credit or charge, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment Clause DSC-17, or its currently applicable successor clause, if any.

(g) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any.

(2) Energy Charge:

(b) Base Energy Charge:

On-Peak kWh @ $0.0575/kWh

Off-Peak kWh @ $0.0375/kWh

(e) ....
For all energy taken during the month and classified under the Off-Peak Demand provision, an Off-Peak Energy Premium of $0.02104/kWh shall apply. Such charge shall be in addition to the Off-Peak Base Energy Charges above.

(f) Fuel Adjustment Charge:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-17, or its currently applicable successor clause, if any, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.09, respectively.

(C) Charges Under Applicable Riders:

The monthly charges hereunder shall include the charges for services provided the Customer under any and all applicable riders hereto.

(D) Monthly Facilities Charges:

In the event service to the Customer requires the Authority to provide facilities in addition to, or different from, facilities normally provided by the Authority, and the Authority provides such facilities, the Customer also shall pay the Authority a Monthly Facilities Charge, in addition to all other charges hereunder. Such Monthly Facilities Charge shall be equal to 1.4% of the original installed cost of such facilities.

(E) Minimum Monthly Bill:

The minimum monthly bill shall consist of the sum of (i) the Monthly Customer Charge, (ii) the Monthly Facilities Charge, if any, (iii) the Monthly Demand Charge for Firm Power Service, and (iv) the minimum monthly charges, if any, determined pursuant to any applicable rider or riders under which the Customer also receives service from the Authority.

(F) Taxes and Other Assessments:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the foregoing monthly rates and charges. The total monthly billing amount hereunder also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Determination of Demands:

(A) Firm Billing Demand:

(1) The Firm Billing Demand for each Billing Month shall be greater of (i) On-Peak Measured Demand, or (ii) eighty percent (80%) of the Firm Contract Demand, but no greater than one hundred (100%) of Firm Contract Demand for such Billing Month. If the Customer receives Firm Power only, then the Customer's Firm Billing Demand shall not be less than 1,000 kW.

(2) In the event that, during any Billing Month, the provision of service by the Authority hereunder is interrupted for a period of four (4) or more consecutive hours as a result of an occurrence of one of the circumstances set forth in Section 9(A) of the General Terms and Conditions, the Firm Billing Demand for such Billing Month will be reduced by the proportion which the number of hours of such interruption bears to the total number of hours in the Billing Month.

(3) The Customer's Off-Peak Demand Provision shall refer to the amount, if any, by which (a) the lesser of (i) Off-Peak Measured Demand during that Billing Month or (ii) the Customer's then current Off-Peak Maximum demand exceeds (b) the sum of the Firm Contract Demand hereunder plus the Customer's Contract Demands (if any) under any and all riders hereto and other rate schedules of the Authority, plus the Customer's Excess Firm On-Peak Demand (if any) during that billing month. The Customer's Off-Peak Maximum Demand shall be established at the request of the Customer and modified by the Authority from time to time in recognition of the limitations of the delivery facilities serving the Customer and other limiting considerations on the Authority's system however, in no event shall requested demand exceed 20 percent (20%) of the sum of the Customer's Firm and Interruptible Contract Demand(s). Unless and until the authority shall have agreed in writing to a specific Off-Peak Maximum Demand, it shall be deemed to be equal to the sum of the Firm Contract Demand hereunder plus the Customer's Contract Demand(s) (if any) under any and all riders hereto and other rate schedules of the Authority, exclusive of Nominated of curtailed capacity as provided under L-17-DRB. All energy served under the Off-Peak Demand Provision shall incur charges as described in Section 3(B)(2)(b).

(4) Firm Billing Demand, and the Off-Peak Demand Provision, as described and calculated herein, shall be exclusive of Nominated or curtailed capacity as provided under L-17-DRB, including provisions for Customer's Contract Demand(s) in Section 4 (A) (1) and Section 4 (A) (3) above.

(B) Measured Demand:

(1) Subject to the applicable provisions, if any, of any rider or riders hereto pursuant to which the Customer also receives service, the Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the customer during such Billing Month.

(2) The On-Peak Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the Customer that shall have occurred during the Billing Month during On-Peak Demand Hours. As used herein, On-Peak Demand Hours shall refer to the same as stated in Section 5(A).

(3) The Off-Peak Measured Demand shall be the maximum 30-minute integrated kW demand of the Customer that shall have occurred in the Billing Month at a time other than during On-Peak Demand Hours.

(4) In determining each of the Customer's Measured Demand, On-Peak Measured Demand, and Off-Peak Measured Demand, whenever the Customer's load is unbalanced between phases by more than ten percent (10%), the load on each phase shall be deemed to be equal to the greatest load on any phase. Furthermore, whenever the Customer's load frequently is found to be unbalanced between phases by more than ten percent (10%), the Authority, at its sole option, may require the Customer, at the Customer's expense, to make the changes necessary to correct such condition.

(C) Firm Contract Demand:

(1) Except as otherwise provided herein, the Firm Contract Demand applicable to each Delivery Point during each Billing Month shall be the maximum amount of Firm Power, in kilowatts, that the Customer shall have requested and the Authority shall have agreed to supply during such Billing Month, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and made a part of, the Service Agreement between the Customer and the Authority. During the first twelve (12) months of service to a new Delivery Point, the Authority, at its sole option, may agree to adjust the Customer's Firm Contract Demand on a month-to-month basis and/or to forego the application of the Section 4 (D) here in below, in order to allow the Customer and the Authority an adequate build-up or phase-in of operations; provided, however, that the Authority reserves the right to condition such agreement on such additional terms and conditions as the Authority deems appropriate for the circumstances.

(2) Except as otherwise provided herein or in the General Terms and Conditions, the Customer may reduce its Firm Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month period(s), to not less than 300 kW by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of service to the Delivery Point, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Firm Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Firm Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Firm Contract Demand for such year.

(d) For the fourth and subsequent twelve month period(s), the maximum reduction shall be 100% of the respective Firm Contract Demand(s) for such years.

Notices of such reductions in the Customer's Firm Contract Demand shall be irrevocable once given.

(3) The Customer's Firm Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rate Schedule or applicable rider(s) hereto under which the Customer also receives service, or (ii) by mutual agreement between the Authority and the Customer

evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional, special terms and conditions applicable to service to the Customer to be included in the aforementioned new Delivery Point Specification Sheet.

(4) Notwithstanding any other provisions hereof, in no event shall the Customer's Firm Contract Demand be less than the amount, if any, by which the sum of the Customer's then current contract demands under all applicable riders hereto is less than 1,000 kW.

(D) Excess Demand:

(1) The Customer's Excess On-Peak Billed Demand for each Billing Month shall be the greater of (a) that portion of the Customer's On-Peak Measured Demand for such Billing Month, if any, that exceeds the sum of (i) the Customer's then current Firm and Interruptible Billed Demand hereunder, and, where applicable, (ii) the Customers' Contract Demand(s), if any, under any and all applicable rider or riders to which the Customer also receives service from the Authority, exclusive of L-17-DRB or its successor.

(2) The Customer's Excess Off-Peak Demand for each Billing Month shall be that portion of the Customer's Off-Peak Measured Demand for such Billing Month, if any, that exceeds the sum of the Customer's then-current Off-Peak Maximum Demand and the Excess On-Peak Billed Demand above.

(3) Notwithstanding the foregoing or any other provision of this Rate Schedule or the General Terms and Conditions to the contrary, in the event that, at any time, (i) the Customer's rate of use of electricity at a Delivery Point exceeds the Customer's Maximum Demand applicable at that time, and (ii) the Customer fails to comply promptly with a request by the Authority to reduce such rate of use so as not to exceed such Maximum Demand, the Customer's Firm Contract Demand(s) for such Delivery Point for the current and subsequent Billing Months, shall at the Authority's sole option, be increased, from what it otherwise would have been, by the amount of such excess. In addition, in such event, the Customer shall be liable for any damage to the Authority's facilities caused by such excess. The Customer's Maximum Demand during Peak Demand Hours shall be equal to the sum of (i) the Customer's then current Firm Contract Demand hereunder and, where applicable, (ii) the Customer's then current Contract Demand(s), if any, under applicable riders hereto. The Customer's Maximum Demand in hours other than Peak Demand Hours shall be equal to the Customer's then current Off-Peak Maximum Demand.

(4) Notwithstanding the foregoing or any other provision of this Rate Schedule or the General Terms and Conditions, the Authority shall be under no obligation whatsoever to supply demands in excess of the Customer's aggregate Contract Demand(s), and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed the Customer's aggregate Contract Demands.

(E) Excess Reactive Demand:

The Customer's Excess Reactive Demand for each Billing Month shall be the amount, if any, by which the Customer's maximum 30-minute integrated reactive demand, in kilovars (kVAr), during such Billing Month exceeds 48.5% of the Customer's Measured Demand, in kilowatts (kW), for such Billing Month.

Section 5. Determination of On-Peak and Off-Peak Hours:

(C) Demand

(1) On-Peak Demand Hours

i. Summer On-Peak Demand Hours shall mean the hours from 1:00 p.m. to 10:00 p.m., Monday through Friday, for the months of May, June, July, August, and September.

ii. Non-Summer On-Peak Demand Hours shall mean the hours from 5:00 a.m. to 9:00 a.m. and from 6:00 p.m. to 10:00 p.m., Monday through Friday, for all other months.

(2) Off-Peak Demand Hours

i. The Off-Peak Demand Hours are defined as all hours not specified above as On-Peak Demand Hours. The Authority may call for additional Off-Peak Demand Hours from time to time based on operational limitations or cost constraints. Additional Off-Peak Demand hours shall be designated at the sole discretion of the Authority.

(D) Energy

(1).. On-Peak kWh are defined as all kWh consumed by the customer during the calendar months of June, July and August between the hours of 1PM and 10PM during weekdays (prevailing time).

(E).. Off-Peak kWh are defined as all kWh consumed by the customer during all other hours of the year.

Section 6. Additional Terms and Conditions:

Service under this Rate Schedule, including service under all applicable riders hereto, is subject to the then currently effective General Terms and Conditions and the Service Agreement between the Customer and the Authority.

Adopted ____________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule L-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)

General Terms and Conditions
of
Large Power Electric Service

Section 1. Contract For Service

(A) As a condition precedent to the Authority supplying electric service under the Authority's Large Light and Power Rate Schedule L-17 and/or any and all riders thereto (collectively, "Schedule L"), to which these General Terms and Conditions are attached and made a part of, the Customer shall execute a Service Agreement in the form hereinafter provided as Exhibit I hereto. When executed by the Customer and the Authority, such Service Agreement, together with Schedule L, these General Terms and Conditions, and applicable notices of Contract Demands accepted by the Authority, shall constitute the entire contract for service between the Authority and the Customer.

(B) In the event of any conflict between these General Terms and Conditions and the provisions of the Service Agreement or Schedule L, the provisions of the Service Agreement or Schedule L shall govern.

(C) Nothing contained in any and all parts of Schedule L, the Service Agreement, and these General Terms and Conditions, shall be construed as affecting in any way the right of the Authority to make changes to any and all parts of such documents as provided by law.

(D) A separate Delivery Point Specification Sheet, in the form hereinafter provided as Exhibit II hereto, shall be prepared and executed by the Authority and the Customer for each Delivery Point at which the Customer is to receive service. Each such Delivery Point Specification Sheet, shall be deemed to be attached to, and made a part of, the Service Agreement between the Customer and the Authority.

(E) As used herein, "Delivery Point" refers to the point or points at which the electrical conductors (including bus bars) of the Authority are connected to the electrical conductors of the Customer or, in the case of service hereunder to a municipal or cooperative wholesale Customer of the Authority, to the conductors of that Customer or a retail customer of wholesale Customer. The Authority shall normally provide one three-phase service at a single voltage at each Delivery Point. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed.

Section 2. Conditions of Service

(A) The Authority's agreement to provide electric service on the date specified for electric service to each Delivery Point, subject to proper written notice as set forth in the applicable Rate Schedule, is contingent upon the Authority's ability to acquire, at a sufficient time prior to the date for commencement of such service, the necessary State and Federal approvals and the necessary rights of way and equipment for providing such electric service.

(B) With respect to facilities installed by the Authority to provide electric service to the Customer, the Authority reserves the right to use any available capacity of such facilities not needed for such service to supply other customers of the Authority.

Section 3. Electric Service Provided

(A) The Authority will provide electric service to Customer in the form of unregulated, three-phase alternating current at a frequency of approximately 60 Hertz.

(B) The Authority will provide electric service pursuant to the provisions of Schedule L at the nominal voltage desired by Customer provided such voltage is generally available in the area in which the electric service is desired. For Delivery Points existing on the date these General Terms and Conditions become effective, the nominal voltage supplied shall be the Authority's present nominal delivery voltage at such Delivery Points.

(C) The Authority will provide electric service for each Delivery Point at the nominal voltage specified in the Exhibit II to the Service Agreement for the Delivery Point, unless the Authority notifies the Customer in writing that the voltage will be changed to a specified higher or lower voltage in accordance with usual utility practices. In such cases, the Customer at the Customer's own expense will design, engineer, install, construct or modify, operate, and maintain facilities to such higher or lower voltage.

Section 4. Monthly Billing and Payment

(A) The Authority shall render to the Customer, after the end of each Billing Month, a bill setting forth the charges, as specified in Schedule L, for such Billing Month. "Billing Month" refers to a period between successive meter readings, which shall normally be once per month.

(B) All bills shall be on a net basis, and each such bill shall be due and payable in good funds at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of one hundred dollars ($100.00), or two percent (2%) of the amount then outstanding including late payment charges. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of the service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 5. Metering and Measurement

(A) Power and energy shall be metered by the Authority at, or as if at, each Delivery Point.

(B) Not less frequently than once each year, the Authority shall make periodic tests and inspections of meters installed by it. At the request of the Customer, the Authority shall make additional tests or inspections. Readings of metering instruments found to be in error by more than two percent (2%) either fast or slow will be corrected and credits or debits made to the Customer's account accordingly. Such correction shall apply for a period of not more than thirty (30) days prior to the date of test unless a longer period of inaccuracy can be definitely determined. The Customer shall pay all costs resulting from additional tests requested by the Customer if tests show meters to be accurate within two percent (2%).

Section 6. Use of Service

(A) Power shall be used in such manner as will not cause objectionable voltage fluctuations or other electrical disturbances on the Authority's system. If such fluctuations and disturbances become objectionable, the Authority may require the Customer, at the Customer's own expense, to install appropriate corrective equipment.

(B) The Service Agreement shall not be assigned by the Customer without approval in writing by the Authority. Service hereunder is exclusively for use by the Customer, and is not to be resold or shared with others. In consideration of the terms of the Service Agreement and these General Terms and Conditions, and in recognition of the fact that the supplying of power and energy from more than one source to the Customer's Facilities may adversely affect safety and the Authority's operations, the Customer agrees not to accept electrical service for said plant operations from any source other than the Authority during the terms of the Service Agreement.

Section 7. New Delivery Points

(A) To establish a new Delivery Point, the Customer must execute with the Authority a new Delivery Point Specification Sheet for the new Delivery Point prior to the date upon which the new Delivery Point is to be placed in service. Such new Delivery Point Specification Sheet shall be attached to, and made a part of, the Service Agreement and shall include any special provisions required for the establishment of the new Delivery Point. The execution of such Delivery Point Specification Sheet shall be a condition precedent to the Authority's supplying electric service to the Delivery Point.

(B) The Authority shall not be obligated to establish any new Delivery Point if it is reasonably determined by the Authority that, consistent with Prudent Utility Practice, the new Delivery Point is not necessary or appropriate for the delivery of power to serve load on the Customer's system.

(C) The Authority shall not be obligated to establish any new Delivery Point if after exercising due diligence the Authority cannot obtain all necessary State and Federal approvals, rights-of-way, and equipment. The Customer shall support all State and Federal filings that the Authority deems necessary (i) for supplying capacity and energy to the new Delivery Point, (ii) for the construction and permitting of the new Delivery Point, and (iii) such other facilities as the Authority deems necessary for the new Delivery Point.

(D) The Customer or potential Customer requesting the establishment of a new Delivery Point shall submit a detailed written request to the Authority specifying the requirements of such Delivery Point.

(E) Except as otherwise provided herein, the Customer is responsible for the installation, operation and maintenance of all necessary poles, lines, substations, transformers, switches, protective equipment, and other equipment (except the Authority's metering equipment) necessary for the establishment of a new Delivery Point, and for all facility rearrangements on the Customer's side of such Delivery Point that are required for the establishment thereof.

(F) Substantial and/or material modifications to an existing Delivery Point shall be deemed to constitute the termination of such Delivery Point and the establishment of a new Delivery Point.

Section 8. Delivery Points and Other Facilities

(A) The service specifications for each Delivery Point shall be as prescribed in the corresponding Delivery Point Specification Sheet.

(B) For each Delivery Point, the Customer shall provide, free of cost to the Authority, a suitable site on the premises for the installation by the Authority of equipment for rendering service hereunder. The Customer shall also provide for the safekeeping of this equipment and shall not permit anyone other than authorized employees and agents of the Customer and employees and agents of the Authority to have access thereto.

(C) The Customer hereby grants to the Authority for the entire term of this contract, free of cost, the right to construct, operate and maintain on property owned, leased or controlled by the Customer, all poles, conductors, appurtenances and equipment whatsoever reasonably necessary or desirable for supplying service hereunder to each Delivery Point. The Authority shall also have all rights of access to said property reasonably necessary or desirable for the aforesaid purposes and the right to remove all or any portion of the Authority's property at any time during the term of this contract or within a reasonable time thereafter. All property, structures and facilities erected by the Authority on property of the Customer are recognized and agreed by the parties to be removable trade fixtures, which shall be and remain personal property of the Authority whether affixed to the realty or not.

(D) Employees of the Authority shall be allowed access to the service installation site at all reasonable hours for the purpose of reading the metering instruments, inspecting the property of the Authority, removing such property, and for other purposes incident to the supplying of service to the Customer.

(E) All electrical facilities used or constructed by the Customer must conform to accepted modern practice and to applicable state and local requirements and must conform to the requirements of the National Electrical Safety Code and National Electrical Code.

(F) All facilities on the Customer's side of each Delivery Point shall be considered the system of the Customer, shall be paid for by the Customer, and shall be installed, operated, and maintained by the Customer at the Customer's expense; provided, that (i) the Authority's metering equipment, if any, located on the Customer's side of a Delivery Point will be owned, installed, operated, and maintained by the Authority; and (ii) the Authority shall have the right, at the Authority's option, to install and/or maintain such other facilities on Customer's side of a Delivery Point as the Authority may elect in the interests of system reliability.

(G) The Customer shall not utilize, or allow to be utilized, any equipment, appliance, or device that tends to unreasonably adversely affect the system of the Authority. The Customer shall maintain a reasonable electrical balance between the phases at each Delivery Point.

(H) The Customer shall install and maintain suitable protective devices on the Customer's system in order to afford reasonably adequate protection to the facilities of the Authority against adverse conditions or disturbances originating on Customer's system. Such protective devices shall be in accordance with the applicable industry standards relating to such equipment and with such other requirements as the Authority may reasonably deem necessary.

(I) The Authority shall install, own, operate, and maintain all lines and equipment located on the Authority's side of each Delivery Point, as well as the meter and metering equipment and, if applicable, any backup meter and metering equipment that may, at the Authority's option, be located on Customer's side of each Delivery Point. In such cases, Customer shall provide a location, acceptable to the Authority, for the installation of such metering equipment.

(J) In the event that the Customer requests the Authority to supply electricity in a manner requiring facilities in addition to or different from those normally provided by the Authority, the Authority will provide such facilities on the Authority's side of the Delivery Point, if practical to do so, provided the following conditions are met and a new Delivery Point Specification Sheet for such Delivery Point is executed to reflect these conditions:

1) The Customer requesting the facilities shall submit a detailed written request to the Authority specifying the type and kind of facilities;

2) The facilities are of a kind and type used by, or acceptable to, the Authority and are, installed in a place and in a manner acceptable to the Authority; and

3) The Customer agrees, in the Delivery Point Specification Sheet for the subject Delivery Point, to pay to the Authority the cost of the facilities prior to their installation or, at the Authority's sole option, appropriate Monthly Facilities Charges in lieu thereof, in addition to the other charges recoverable under Schedule L.

4) Meters and metering related equipment will be sized according to On-Peak Contract Demand, as specified by customer. Costs associated with metering and metering related equipment required to appropriately measure demand in excess of On-Peak Contract Demand will be the responsibility of the Customer. The Authority, as its sole option, may collect costs associated with meters and metering equipment, or upgrades associated therewith, within the appropriate Monthly Facilities Charge.

(K) In the event that the Customer's contract demand(s) under Schedule L (including any applicable riders thereto) is (are) reduced, nothing herein shall be construed as restricting the right of the Authority to change or reduce accordingly the capacity of the Authority's facilities serving the Customer.

(L) The Delivery Point Specification Sheet for each Delivery Point shall set forth appropriate provisions concerning the installation and maintenance of the Delivery Point and shall provide for adequate compensation to the Authority on termination of the Delivery Point by the Customer.

Section 9. Interruption of Service

(A) The Authority will make reasonable provisions to ensure satisfactory and continuous service but does not guarantee a continuous supply of electrical energy and shall not be liable for damage occasioned by interruptions of service or failure to commence delivery caused by an act of God, or the public enemy, or for any cause reasonably beyond the Authority's control, including, but not limited to, the failure or breakdown of generating or transmitting facilities, floods, fire, strikes or action or order of any agency having jurisdiction over the premises, or for interruptions that the Authority deems necessary for the inspection of, repair to, or changes to the Authority's facilities.

(B) Nothing herein shall be construed as restricting in any way the Authority's right to interrupt service to the Customer as the Authority may deem necessary or appropriate to facilitate inspection of, repair to, or changes to the Authority's facilities consistent with Prudent Utility Practice; provided, however, that the Authority shall use its reasonable best efforts, when practicable, to provide the Customer with advance notice of such interruptions and to coordinate with the Customer the times of such interruptions. In any event, failure of the Authority and the Customer to agree upon the time of such an interruption shall not restrict the Authority from proceeding therewith as the Authority deems necessary.

(C) The Customer shall provide written notification to the Authority immediately of any defects, trouble or accident which may in any way affect the delivery of power by the Authority to the Customer.

(D) Notwithstanding any provisions of Schedule L to the contrary, the Customer shall not be liable for any charges under this Schedule for any period during which he is unable to accept electric service due to strikes, fire, floods, or act of God or the public enemy.

(E) Both the Customer and the Authority shall use all due diligence in removing any causes which prevent the delivery or use of electrical power and energy hereunder.

(F) Any claims against the Authority resulting from an interruption of service shall be governed by the terms, conditions and limitations of the South Carolina Tort Claims Act, and any recovery in such claim shall not include indirect or consequential damages.

Section 10. Indemnity

All electrical power and energy provided for hereunder shall be the property of the Customer upon passing the Delivery Point(s) and the Customer shall have sole responsibility for the use, misuse or presence of said power and energy on the Customer's side of the Delivery Point(s). The Customer will indemnify and hold the Authority harmless from all claims, loss or expense arising from, or in any way connected with, the presence, use or misuse of electrical power and energy on the Customer's side of the Delivery Point(s).

Section 11. Determination of Contract Demands

The maximum amount, or amounts, of electric power and energy that the Authority agrees to sell, and that the Customer agrees to purchase at each Delivery Point (the Customer's "Contract Demand(s)") initially shall be set forth in the Delivery Point Specification Sheet for such Delivery Point. The initial establishment of, and subsequent changes to, such Contract Demand(s) shall be made only pursuant to the applicable provisions of Schedule L; provided, however, that the Authority reserves the right to require, for any Customer or potential Customer having a load of greater than 100,000 kW, notice requirements for changes in that Customer's Contract Demands(s) longer than those set forth in Schedule L.

Section 12. Term of Contract

(A) The Service Agreement, terminating on its effective date all prior agreements between the parties, shall become effective on the date specified therein, and shall remain in effect for an initial term of five (5) years, and thereafter for additional terms of two (2) years such, unless terminated by written notice of such intention from either party to the other at least one (1) year prior to the expiration date of the initial term or subsequent term; provided, however, that in no event shall the Service Agreement expire prior to (i) the expiration of the initial term as outlined above, or (ii) the reduction of the Customer's Contract Demand(s) to zero in the manner or manners specified in Schedule L. Nothing herein contained shall in any way bar the right of the Authority to collect any sums due it at the termination of the prior agreements.

If the Customer discontinues operations prior to the expiration of the initial term of the Service Agreement, or any subsequent term, or defaults under this Service Agreement in any respect and the Authority terminates the Service Agreement as a result of such default, the Customer agrees to pay to the Authority, on demand, a sum equal to the cumulative total of the Minimum Monthly Bills, as determined under Schedule L, for the remainder of the term of the Service Agreement, or any subsequent term.

(B) "Contract Year" shall be a twelve-month period beginning on the earlier of (i) the anniversary of the date service is initiated or (ii) the anniversary of the effective date of the Service Agreement.

(C) Schedule L and these General Terms and Conditions may be amended or revised by the Authority from time to time, in whole or in part, to reflect changed conditions, and when so amended or revised shall become effective as to all customers receiving service hereunder.

Section 13. Waiver

Any failure at any time by the Authority or the Customer to enforce a provision of Schedule L, these General Terms and Conditions, or the Service Agreement, shall not constitute a waiver by such party of said provision.

Section 14. Other Contracts

(A) Notwithstanding any other provision of Schedule L or these General Terms and Conditions to the contrary, an existing contract between the Authority and a Customer for the provision of service to such Customer pursuant to the Authority's Large Light and Power Rate Schedule that is in effect on the effective date of these General Terms and Conditions shall continue in full force and effect until its expiration. Such existing contract shall be deemed to constitute the Service Agreement between the Customer and the Authority hereunder until its expiration. In the event any provision of these General Terms and Conditions or Schedule L conflicts with a provision of such existing contract, the provision of the contract shall prevail.

(B) Upon the expiration of an existing contract between a Customer and the Authority, as described in the foregoing paragraph, continued service to such Customer shall be wholly subject to Schedule L and these Terms and Conditions.

(C) The establishment of a new Delivery Point, or the substantial modification of an existing Delivery Point, for a Customer having an existing contract, as described in the foregoing two paragraphs, shall require the termination of such existing contract and the execution of a new Service Agreement of the form specified in Exhibit I hereto.

(D) The terms and conditions of service to a Customer at a Delivery Point or Delivery Points under any rate schedule(s) or contract(s) other than Schedule L shall be unaffected by the terms of Schedule L and these General Terms and Conditions and shall be governed solely by the terms of such other rate schedule(s) or contract(s). The terms and conditions and service to each Delivery Point pursuant to Schedule L shall be governed solely by the provisions of Schedule L and these General Terms and Conditions and shall be unaffected by service, if any, to a Delivery Point or Delivery Points under any other rate schedule(s) or contract(s) between the Customer and the Authority.

(E) Acceptance of service under Schedule L without the benefit of an executed Service Agreement or another formal, written contract between the Customer and the Authority will bind the Customer to all terms and conditions of Schedule L and these General Terms and Conditions the same as if a formal written contract had been executed. In such event, all obligations hereunder shall begin on the date of such acceptance of service and shall continue for an initial term of five (5) years and thereafter for additional terms of two (2) years each, unless and until terminated at the end of such initial term or any additional term by no less than one (1) year's advance written notice of termination from either party to the other.

Adopted __________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule L-16, Attachment A, Effective April 1, 2016

Exhibit I

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
SERVICE AGREEMENT FOR LARGE POWER ELECTRIC SERVICE

This Agreement made and entered in this ______ day of ________________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and _________________________, hereinafter referred to as the "Customer."

W I T N E S S E T H:

That in consideration of the mutual covenants and agreements herein contained, the Authority and the Customer covenant and agree with each other as follows:

1. The Authority shall sell and deliver to the Customer, and the Customer shall purchase and receive from the Authority, the Customer's full requirements for electric service at the Delivery Point(s) specified in the respective Delivery Point Specification Sheets attached to this Service Agreement. Each such Delivery Point Specification Sheet shall, upon its execution, be a part of this Service Agreement, and shall include the service specifications for the provision of service at the corresponding Delivery Point.

2. A change in the service specifications at a Delivery Point shall require a new Delivery Point Specification Sheet to be executed to replace the previous Delivery Point Specification Sheet for that Delivery Point.

3. This Service Agreement adopts and incorporates by reference all of the provisions of the Authority's Large Light and Power Rate Schedule L-17 and all riders thereto (collectively, "Schedule L"), and its associated General Terms and Conditions, as such Schedule L and General Terms and Conditions may be changed from time to time.

4. The Customer shall pay the Authority monthly for electric service rendered hereunder pursuant to the applicable Rate Schedule and in accordance with the billing and payment provisions of Schedule L and the General Terms and Conditions.

5. This Service Agreement may not be assigned by either Party without the prior written consent of the other Party, provided, however, such consent shall not be unreasonably withheld.

6. If any provision of this Service Agreement is inconsistent with any provision of any applicable rate schedule or associated riders, the provisions of this Service Agreement shall prevail.

7. Subject to the provisions hereinbefore contained, this contract shall be binding upon and inure to the benefit of the successors and assigns of the parties hereto.

IN WITNESS WHEREOF, the Authority and the Customer have caused this Service Agreement for the Large Power Electric Service to be executed in duplicate in their names by their respective duly authorized officials, as of the day and year first above written.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ___________________________	**BY:** ___________________________
ATTEST:	_________________________________ **(CUSTOMER)**
BY: ___________________________	**BY:** ___________________________

Exhibit II

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
SERVICE AGREEMENT FOR LARGE POWER ELECTRIC SERVICE
DELIVERY POINT SPECIFICATION SHEET

1. Electric Service Supplied to:

2. Delivery Point Information:

   (a) Name:
   (b) Description:
   (c) Location:

3. Original Effective Date of Delivery Point:

4. Effective Date of this Specification Sheet:

5. Contract Demand(s):

   (a) Firm Power Contract Demand:
   (b) Interruptible Power Contract Demand:
   (c) Economy Power Contract Demand:
   (d) Standby Power Contract Demand
   (e) Demand Response Buy Back Demand

6. Electric Service Supplied: ____ volts (nominal) ____ Phase

7. Metering Data:

   (a) Metered Voltage:
   (b) Location:
   (c) Compensation:

8. Provisions for Special Facilities or Conditions:

IN WITNESS WHEREOF, the Authority and the Customer have each caused this Delivery Point Specification Sheet, which is to be incorporated into the Service Agreement for Large Power Electric Service, dated _____________, to be executed in their names by their respective duly authorized officials on this ___ day of ___________, 20__.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ____________________________	**BY:** ____________________________
ATTEST:	___________________________________ **(CUSTOMER)**
BY: ____________________________	**BY:** ____________________________

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
INTERRUPTIBLE SERVICE
RIDER L-17-I

Section 1. Availability:

(A) Service hereunder, "Interruptible Power", is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-17 or its successor (hereinafter, "Schedule L"), to which this Rider L-17-I is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-17-I, the sum of the Customer's Contract Demands under this Rider L-17-I plus the Customer's Firm Contract Demand must equal or exceed 1,000 kW.

(C) The total amount of Interruptible Power available to all customers changes from time to time and the availability of such power hereunder is strictly subject to the provisions of this Rider L-17-I, including, without limitation, Section 4 (B)(4) herein below. As of January 1, 2012, the Authority has determined that Interruptible Power service will be made available to existing customers under contract and additional qualifying customers on a “first come first served” basis up to a maximum aggregate amount based on the Authority’s reserve requirement.

Section 2. Character of Service:

(A) Interruptible Power hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L that (i) is in excess of Firm Power purchased by the Customer under Schedule L, and (ii) is interruptible or curtailable by the Authority in accordance with the following terms of this Rider.

(B) Curtailments by the Authority

(4) The Authority shall have the right, at any time or times and for any reason or reasons, to interrupt or call for curtailment of all or part of the Interruptible Power in response to an Emergency Event. As used herein, an “Emergency Event” means a condition on the Authority’s system in which, in the sole judgment of the Authority’s System Controller, action is required to maintain compliance with approved Reliability Standards or there is an imminent danger of deterioration of service to firm customers, voltage collapse, or damage to a part of the system.

(5) The Authority shall have the right, at any time or times and for any reason or reasons, to interrupt of call for curtailment of all or part of the Interruptible power in response to market or system conditions, hereinafter “Economic Curtailments”, not deemed Emergency Events. Such Economic Curtailments shall not exceed 250 hours, nor occur in more than 60 days, in any calendar year and, provided further, the number of such Economic Curtailments shall not exceed two (2) in any calendar day or 72 hours in any calendar week (Monday through Sunday.) Electrical power and energy purchased by the Customer pursuant to this section shall be classified as "Secondary Power."

(a) During the months of January, February, and December, the Authority reserves the right to curtail custumers for not longer than 48 consecutive hours. The Authority shall use good faith efforts to alert the Customer of such curtailment with at minimum 12 hours notification. With each such notification, the Authority shall supply the Customer with a quotation of the energy prices, in cents per kilowatt hour, applicable to power taken during the hours to which the notification applies. Curtailment hours shall be considered used when called.

(b) At any time or times, except as provided in Section 2(B)(2)(c) below, the Authority reserves the right to curtail customers for not longer than twelve (12) aggregate hours in any calendar day. Such curtailments shall occur independently from curtailments described in Section 2(B)(2)(a) above and such curtailments may occur during the same clock hour. In the event that the Authority deems it necessary and prudent to call for curtailment during the same clock hour for which another curtailment has been called, all provisions of the previous curtailment for the clock hour, including quoted prices and scheduled usage, shall be considered null and void.

(c) In the event that the Authority designates Economic Curtailments for greater than 24 continuous clock hours, the 12 hours immediately following the termination of the Economic Curtailment period shall be considered exempt from Economic Curtailments. Such limitation shall in no way restrict the duration of a single continuous Economic Curtailment period.

(d) In order to receive Secondary Power at a Delivery Point during an hour, the Customer shall respond to the Authority's notification for curtailment within a period of time to be established by the Authority, following such notice. Such responses shall include the maximum 30-minute integrated kW demand the Customer requests and is willing to receive during each period of time, hereinafter the interval, determined by the Authority, subject to its availability. The Authority, at it's option, may respond to and confirm agreement to the Customer's request or may not respond further, in which event such confirmation and agreement shall be deemed to have been given.

(e) As used herein, "Scheduled Secondary Demand" shall, for any hour, be the maximum 30-minute integrated kW scheduled for delivery to the Customer during such hour pursuant to this Rider L-17-I. "Delivered Secondary Demand", shall be the maximum 30-minute integrated kW demand by which the metered deliveries of power and energy to the Customer during the interval exceed theCustomer's then-current Firm Contract Demand under Schedule L.

(6) The Authority shall establish and maintain operational guidelines which shall state the conditions and circumstances under which calls for curtailments may be made. Such operational guidelines shall be published, and available for review, at the Authority's offices.

(4) When the Authority wishes to interrupt or curtail the Customer's Interruptible Power as provided herein, the Authority shall give notice thereof to the Customer by telephone or by such other means as the Authority may from time to time designate. Each such notice shall specify a demand level, which may be zero, to which the Customer's use of Interruptible Power is to be limited and the time period (hereinafter, a "Curtailment Period") to which such limitation is to apply. After receiving such a notice, the Customer shall, except as otherwise provided herein, limit the Customer's use of Interruptible Power during the Curtailment Period to which the notice applies, to the level specified by the Authority. Each such notice shall be deemed received by the Customer if the Authority shall have issued or attempted to issue that notice.

(5) The Authority will use reasonable efforts to give as much advance notice as practicable of probable curtailments when circumstances permit. The final scheduling of Emergency Event curtailments by the Authority will be postponed as long as practicable in order to minimize their occurrence and duration. Each notice issued by the Authority may be withdrawn or modified prior to the beginning of the potential Curtailment Period to which it applies. Such withdrawal or modifications shall be issued to the Customer by the same means as the original notices. Notices, if and to the extent so modified, shall be deemed to establish final Curtailment Periods and demand limitations. Notices withdrawn prior to the beginning of their respective Curtailment Period shall be without any further force or effect. The Authority shall confirm final notices of curtailment by subsequent letter to the Customer as soon as reasonably practicable after the end of the respective Curtailment Periods.

(6) After a notice of curtailment shall have been issued by the Authority, the Customer shall have the right to exceed the demand limitation set forth in the notice if, and only if, (i) the Customer makes a request to do so pursuant to the timetable established for the Curtailment Period to which the notice applies and the Authority, in its sole judgment, determines that it can supply the requested excess, and (ii) the Customer agrees to pay for such excess at the price(s) quoted by the Authority in response to such request. The Authority shall designate in writing from time to time a representative to whom such requests should be directed, and the Customer shall designate in writing from time to time a representative of the Customer who is authorized to make such requests and issue such agreements. Requests that are granted and the corresponding agreements to pay the quoted prices shall be confirmed in writing by the Authority as soon as is reasonably practicable after the corresponding Curtailment Periods have ended.

(7) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period that is not classified as Secondary Power shall be classified as Excess Power; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Power.

Section 3. Monthly Rates and Charges:

For all Interruptible Power provided hereunder, the monthly charge shall consist of the following charges:

(A) Interruptible Power:

For all services provided hereunder other than Secondary Power and Excess Power:

(1) Monthly Demand Charge:

(a) All kW of Interruptible Billing Demand @ $10.31

(d) For each kW of Interruptible Billing Demand, a charge or credit, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment Clause DSC-17, or its currently applicable successor clause, if any.

(e) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-17), or its currently applicable successor clause, if any.

(2) Monthly Energy Charge:

(a) Base Energy Charge:

On-Peak kWh @ $0.0575
Off-Peak kWh @ $0.0375

(b) Fuel Adjustment Charge:

For each kWh, the charge or credit per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-17, or its successor clause, with "F_b/S_b" and "K" of the formula in said clause being equal to \$0.03641/kWh and .085, respectively.

(B) Secondary Power:

(3) The price for Secondary Power used by the Customer in each Curtailment Period shall be the price quoted by the Authority for such power and energy as hereinabove described. Each such quotation shall be based on the Authority's reasonable best estimate of its incremental costs of supplying such Secondary Power, plus a margin of 15% above the Authority's incremental costs.

(4) Scheduling

a. Overscheduling charges shall equal the amount, if any, by which the Customer's Delivered Secondary Demand for the hour was less than 80 percent (80%) of the Customer's Scheduled Secondary Demand for the interval, times 15% of the quoted energy price for the interval times the number of clock hours in the interval. Charges shall not apply to Delivered Secondary Demand within 100 kW of the Customer's Scheduled Secondary Demand for that interval.

b. Underscheduling charges shall equal the amount, if any, by which the Customer's Delivered Secondary Demand for each Economic Curtailment interval exceeds the Customer's Scheduled Secondary Demand for the interval, times 150% of the quoted price for the interval times the number of clock hours in the interval.

c. During a single continuous Economic Curtailment and in lieu of Underscheduling and Overscheduling charges listed in hereinbefore, the total Overscheduling and Underscheduling charges may be levied on the net difference between Delivered Secondary Demand and Scheduled Secondary Demand each interval during the curtailment. Applicable charges for this demand shall be levied at the average quoted price for energy taken during the curtailment period and the average number of interval hours. Such charges shall be at the sole discretion of the Authority.

(C) Excess Power:

The price for Excess Power used by the Customer in each Emergency Event Curtailment Interruption Period as defined in Section 2(B)(1) shall be 150% of the Authority's reasonable best estimate of its incremental cost (including opportunity costs) of supplying such Excess Power. Such incremental costs may include both demand-related and energy-related costs.

In addition, whenever the Customer shall have used Excess Power during an Emergency Event Curtailment Period as defined in Section 2(B)(1), the provisions of Section 4(C) below shall apply.

Section 4. Determination of Demands:

(A) Interruptible Billing Demand

The Customer's Interruptible Billing Demand for each Billing Month shall be the amount, if any, by which the Customer's Measured On-Peak Demand for such month, determined pursuant to Section 4(B) of Schedule L, exceeds the Customer's then-current Firm Billed Demand, under Schedule L, however, that in no event shall such Interruptible Billing Demand be (i) greater than 100% of the interruptible contract demand or (ii) less than 80 percent (80%) of the sum of the Customer's then-current Firm and Interruptible Contract Demand less Firm Billed Demand.

As used in Section 4(A) only, Firm Billed Demand shall include an adjustment for energy billed under Section 3(B)(2)(b) of Schedule L. Such adjustment shall be calculated monthly utilizing the following formula:

*Off-Peak Demand = (Off-Peak Energy / Off-Peak Hours) * 1.5*

where Off-Peak Energy means all energy billed under Section 3(B)(2)(B) of Schdule L and Off-Peak Hours means the total number of Off-Peak demand hours for the month under Section 5(A)(2) of Schedule L.

(B) Interruptible Contract Demand

(1) Except as otherwise provided herein, the Customer's Interruptible Contract Demand shall be the maximum amount of Interruptible Power, in kilowatts, that the Customer has requested and the Authority has agreed to supply, as evidenced in the Delivery Point Specification Sheet for which the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer may reduce its Interruptible Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month periods, by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of the Service Agreement between the Customer and the Authority, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Interruptible Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Interruptible Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Interruptible Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Interruptible Contract Demand(s) for such years.

Notices of such reductions in the Customer's Interruptible Contract Demand shall be irrevocable once given.

(3) The Customer's Interruptible Contract Demand, once established or reduced, may be increased only by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(4) The total amount of Interruptible Power available for sale to all customers changes from time to time. In initially determining the amount of Interruptible Power, if any, to provide a Customer and/or in determining the amount, if any, by which a Customer's Interruptible Contract Demand may be increased, the Authority shall take into account the total amount of such Interruptible Power it reasonably expects to be available and its prior commitments for sales of such power. If, and to the extent that, the Authority thus determines it can make additional Interruptible Power available to new Customers and to existing Customers, the Authority shall do so on a first-come, first-served basis, in accordance with the stated limit of Interruptible Power specified in Section 1 (C) herein.

(C) Excess Demands

(1) In the event the Customer's use of service during any Emergency Event Curtailment Period exceeds the demand level established by the Authority for such Curtailment Period, the Customer's Interruptible Contract Demand shall be reduced, and the Customer's Firm Contract Demand shall be increased, by the greatest 30-minute integrated demand of such excess. In such event, such reduction and such increase each shall apply for the current Billing Month and the subsequent eleven (11) Billing Months.

(2) Notwithstanding the foregoing or any other provision of this Rider L-17-I, Schedule L, or the General Terms and Conditions attached thereto, the Authority shall be under no obligation whatsoever to supply demands in excess of the demand level established by the Authority during a Curtailment Period, and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed such demand level.

Section 5. Other Terms and Conditions:

Service under this Rider L-17-I, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Adopted ____________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule L-16-I, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
ECONOMY POWER SERVICE
RIDER L-17-EP

Section 1. Availability and Applicability

(A) Service hereunder, "Economy Power," shall be available to customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-17 or its successor (hereinafter, "Schedule L"), to which this Rider L-17-EP is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-17-EP, the sum of the Customer's Contract Demands under this Rider L-17-EP plus the sum of the Customer's Firm Contract Demand and Interruptible Contract Demand must equal or exceed 2,000 kW.

Section 2. Character of Service

(A) Economy Power hereunder shall consist of the supply of electric power and energy, of the same general characteristics as described in Schedule L, that the Authority may from time to time, in its sole discretion, determine to be available from the Authority's resources (including the Authority's arrangements with other utilities) in excess of the power and energy requirements of the Authority's other customers.

(B) The Authority shall use good faith efforts to notify the Customer of the availability of Economy Power in each clock hour prior to the beginning of such hour through a means established by the Authority from time to time. With each such notification, the Authority also shall supply the Customer with a quotation of the Economy Energy Price, in cents per kilowatt hour, applicable to Economy Power during the hour to which the notification applies.

(C) In order to receive Economy Power at a Delivery Point during an hour, the Customer shall respond to the Authority's notification for such hour within a period of time, to be established by the Authority, following such notice. Such response shall include the amount of Economy Power the Customer requests and is willing to receive in the applicable hour, subject to its availability. The Authority, at its option, may respond to confirm agreement to the Customer's request or may not respond further, in which event such confirmation and agreement shall be deemed to have been given.

(D) The Authority shall use its reasonable best efforts, but shall be under no obligation whatsoever, to provide periodic estimates of the expected availability and price of Economy Power for upcoming hours and upcoming days. However, such estimates shall be estimates for preliminary planning purposes only, shall be subject to change without notice, and shall have no force or effect. To facilitate the Authority's planning and the aforementioned estimates, the Customer, at the request of the Authority, shall promptly provide the Authority with the Customer's best reasonable estimate of the Customer's requirements for Economy Power in upcoming hours and days. However, such estimates shall be for preliminary planning purposes only, shall be subject to change without notice, and shall have no force or effect.

(E) As used herein, "Scheduled Economy Energy" shall, for any hour, be the amount, if any, of Economy Power scheduled for delivery to the Customer during such hour pursuant to this Rider L-17-EP. "Delivered Economy Energy", for any hour or half-hour, shall be the amount, if any, by which the metered deliveries of power and energy to the Customer in such hour or half-hour exceed the sum of (i) the Customer's then-current Firm Contract Demand under Schedule L, and (ii) the Customer's then current Interruptible Contract Demand, if any, pursuant to Rider L-13-I, but in no event greater than the Customer's then current Economy Power Contract Demand hereunder.

(F) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period identified in Section 4 (B)(2) shall be classified as Excess Economy Power; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Economy Power.

<u>Section 3. Monthly Rates and Charges</u>

Charges to the Customer for Economy Power hereunder shall be equal to the sum of (i) the Monthly Customer Charge, (ii) the Monthly Reservation Charge, (iii) the Monthly Energy Charge, and (iv) the Monthly Excess Economy Power Demand Charge, all as set forth below:

(A) <u>Monthly Customer Charge</u>

The Monthly Customer Charge hereunder shall be $1,000.00 per month for each Billing Month.

(B) <u>Monthly Reservation Charge</u>

The Monthly Reservation Charge hereunder shall be equal to the Customer's Economy Power Contract Demand for such Billing Month, in kilowatts, times $1.81 per kilowatt.

(C) <u>Monthly Energy Charge</u>

The Monthly Energy Charge hereunder shall be the aggregate sum of all applicable Hourly Energy Charges during the Billing Month. Each such Hourly Energy Charge shall be the sum of (1), (2), and (3) below for such hour:

(1) The amount, if any, of Delivered Economy Energy up to the amount of Scheduled Economy Energy for the hour times the Economy Energy Price for that hour;

(2) Overscheduling charges shall equal the amount, if any, by which the Customer's Delivered Economy Energy for the hour was less than 90% of the Customer's Scheduled Economy Energy for the hour, times the Capital Improvement Fund and generation-related charges in the Economy Energy Price as stated in Section 3(C)(3) below; and

(4) Underscheduling charges shall equal he amount, if any, by which the Customer's Delivered Economy Energy for the hour exceeded the Customer's Scheduled Economy Energy for the hour, times 150% of the Economy Energy Price for the hour. In the event that the Authority determines the Economy Energy Price for the hour does not sufficiently recover the costs to serve such excess power, the Authority reserves the right to charge 150% of the Authority's best reasonable estimate of the actual incremental cost to serve. Such decision shall be at the sole discretion of the Authority.

In addition, whenever the Customer shall have used Excess Economy Power during a Curtailment Period, the provisions of Section 4 (B) below shall apply.

For each hour, the aforementioned Economy Energy Price applicable to Economy Power hereunder shall be the price quoted by the Authority for the hour pursuant to Section 2 hereof. For each hour, such Economy Energy Price shall be the greater of (i) the Authority's Incremental Energy Cost, plus markups to include contributions to the Capital Improvement Fund, transmission losses, and generation-related expenses, or (ii) the price at which the Authority could have sold such Economy Power to another utility or utilities, based on actual quotes from such other utility or utilities. Such Incremental Energy Cost shall be the Authority's best reasonable estimate of its out-of-pocket, incremental cost of producing Economy Power during such hour, as determined in accordance with usual utility practice. In no event shall the final Economy Energy Price quoted by the Authority for an hour be subject to after-the-fact adjustment except as allowed in this.
For the purposes of the L-17-EP Economy Energy Price, contributions to generation-related expenses shall equal $8.31/MWH.

For the purposes of the L-17-EP Economy Energy Price, contributions to the Capital Improvement Fund and transmission losses shall equal the Authority's Incremental Energy Cost times a factor of 0.1233. Such charges may be modified from time-to-time.

(D) Monthly Excess Economy Power Demand Charge

The Monthly Excess Economy Power Demand Charge hereunder shall be equal to (i) the greatest 30-minute integrated kW demand of Excess Economy Power, multiplied by (ii) six (6) times the sum of the per-kW rates for the Firm Base Demand Charge and the Excess Demand Charge specified in Schedule L.

(E) Optional Charge(s)

From time to time, at its sole discretion, the Authority may elect to offer customers served under this Rider pricing alternatives. The Optional Charge(s) hereunder shall be set forth along with the terms and conditions of each alternative in writing. The Customer, at its sole discretion, shall have the choice of receiving any portion of Economy Energy under the Optional Charge(s).

Section 4. Determination of Demands

(A) Economy Power Contract Demand

(1) The Customer's Economy Power Contract Demand for each Delivery Point shall be established initially by mutual agreement of the Authority and the Customer, as evidenced in the Delivery Point

Specification Sheet for the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer's Economy Power Contract Demand may be unilaterally reduced by the Customer, in whole or in part, such reduction to become effective at the beginning of a Billing Month specified by the Customer if, and only if, the Customer shall have provided the Authority with at least twenty-four (24) months prior written notice of such reduction. Notices of such reductions in the Customer's Economy Power Contract Demand shall be irrevocable once given.

(3) The Customer's Economy Power Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rider L-17-EP, or (ii) by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require that additional, special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(B) Excess Demands

(1) The amount of Economy Power requested by the Customer in an hour shall be subject to pro rata reduction in the event the Authority determines, in its sole judgement, the aggregate amount of Economy Power so requested by the Customer and all other such customers exceeds the total amount available for such hour. In such event, the Authority shall so notify the Customer prior to the beginning of such hour, and the prorated amount requested by the Customer shall be deemed to supersede the Customer's prior request and shall be deemed to constitute the agreed-upon amount of Economy Power for delivery to the Customer's Delivery Point for that hour, unless the Customer, prior to the beginning of the hour, withdraws its request altogether after receiving such notice from the Authority.

(2) Notwithstanding any other provision of this Rider L-17-EP or Schedule L to the contrary, the Authority shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time that the Authority, in its sole judgement, determines that (i) such Economy Power is no longer available and that continued use thereof by Customer will adversely affect service to the Authority's other customers and/or other utility systems with which the Authority is interconnected, or (ii) circumstances on the Authority's system and/or the systems of any other utility with which the Authority has an interchange arrangement are such that the Authority is unable to supply Economy Power at the Energy Price previously noticed by the Authority. When the Authority calls for such a curtailment, the amount of Economy Power scheduled for delivery to the Customer shall be deemed to be reduced accordingly.

(3) The Authority shall be under no obligation whatsoever to supply Economy Power in an hour in excess of the amount scheduled for delivery to the Customer as herein provided. Nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit deliveries to the Customer to the amounts so scheduled.

Section 5. Other Terms and Conditions

Service under this Rider L-17-EP, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Adopted _____________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes: Schedule L-16-EP,
Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVIC AUTHORITY
(SANTEE COOPER)
L-17-EP-O
Economy Power Service Rider
Optional Energy Charge

Section 3(E) of Rider L-17-EP provides that the Authority may offer pricing alternatives to customers served under the Rider. In accordance with this provision, the Authority offers an Optional Energy Charge as set forth below.

Notwithstanding any provision of L-17-EP to the contrary, an Economy Power (EP) customer, at its sole discretion, may elect to receive its entire Economy Power Service under the following terms and conditions.

c) The monthly Reservation Charge hereunder shall be equal to the Customer's Economy Power Contract Demand for such billing month, in kilowatts, times $3.66 per kilowatt.

d) The Hourly Energy Charge during Off-Peak Periods shall be:

(1) Base Energy Charge:

All kWh @ ………………………………………… $0.0375/kWh

(2) Fuel Adjustment Charge:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-17, or its successor clause, with "Fb/Sb" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.085, respectively.

The Hourly Energy Charge during On-Peak Periods shall be determined as set forth in section 3(C) of the L-17-EP Rider, or its successor.

c) For the purposes of this pricing alternative, "Off-Peak Periods" shall consist of all time periods not designated as On-Peak Periods. Except as provided for in Sections (d) and (e) herein, "On-Peak Periods" shall normally consist of the hours specified in the following table:

Season	On-Peak Hours
Summer (May – September)	11:00 a.m. – 11:00 p.m.
Winter (January, February, November, December)	5:00 a.m. – 11:00 a.m. 5:00 p.m. – 11:00 p.m.
March, April and October	All Off-Peak

d) During the months of January February, and December, the Authority reserves the right to designate additional On-Peak hours as set forth below:

(4) When the Authority determines that its estimated system daily peak demand will be greater than 90% of the projected system peak demand for that winter season (based on the Authority's most recent load forecast), then the Authority may, at its option and with day ahead notice, designate up to twelve additional hours per day as On-Peak

hours.

(5) If the Authority, in accordance with the criteria set forth in Section (d)(1) above, finds it necessary to designate additional On-Peak hours, it will notify affected customers by 12:00 noon on the current day for the following business or non-business day(s).

(6) The ability of the Authority to designate additional On-Peak hours in accordance with this Section (d) shall be limited to no more than seven days per month in each of these months.

e) During the months of March, April and October, the Authority reserves the right to designate additional On-Peak hours as set forth below:

(4) When the Authority projects its Incremental Energy Cost, as set forth in the Economy Power Service Rider, L-17-EP, or its successor, will equal or exceed $55.00/MWh, then the Authority may, at its option and with day ahead notice, designate up to twelve hours per day as On-Peak hours.

(5) If the Authority, in accordance with the criteria set forth in Section (e)(1) above, finds it necessary to designate additional On-Peak hours, it will notify affected customers by 12:00 noon on the current day for the following day.

(6) The ability of the Authority to designate additional On-Peak hours in accordance with this Section (e) shall be limited to no more than seven days per month in each of these months.

f) The Customer will continue to schedule all Economy Energy usage during Off-Peak Periods; failure to schedule may result in discontinuance of this pricing alternative by the Authority to the Customer.

g) Unless specifically contradicted above, all other provisions of Rider L-17-EP, or its successor, remain in effect. The Authority, in its sole judgment, shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time.

h) This pricing alternative is in effect until modified or withdrawn. This pricing alternative is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted ______________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
L-16-EP Economy Power Service Rider
Optional Energy Charge, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVIC AUTHORITY
(SANTEE COOPER)
L-17-EP-AU
Experimental Economy Power Service Rider
As-Used Billing Option

Section 3(E) of Rider L-17-EP provides that the Authority may offer pricing alternatives to customers served under the Rider. In accordance with this provision, the Authority offers an As-Used Billing Option as set forth below.

Service hereunder shall be limited to ten percent (10%) of the customer's total contract demand. Total contract demand shall refer to the sum of the Firm Contract Demand plus the Customer's Contract Demand(s) (if any) under any and all riders hereto and other rate schedules of the Authority, exclusive of Nominated or curtailed capacity as provided under L-17-DRB.

Notwithstanding any provision of L-17-EP to the contrary, an Economy Power (EP) customer, at its sole discretion, may elect to receive its entire Economy Power Service under the following terms and conditions, subject to the limitation above.

d) Service taken under this rider shall not be subject to the Monthly Reservation Charge as defined in Section 3(B) of the L-17-EP rider.

e) The Hourly Energy Charge during On-Peak Periods shall be determined as set forth in Section 3(C) of the L-17-EP Rider, or its successor.

f) The Hourly Energy Charge shall include a charge equal to $0.02104/kWh in addition to all the applicable Hourly Energy Charges listed above.

b) For the purposes of this pricing alternative, "On-Peak Periods" shall consist of the time periods set forth in Section 5(A) of Schedule L-17 or it's successor.

c) Energy taken under this pricing alternative shall not be available during off-peak periods, including any additional off-peak hours as set forth in Section 5(A)(2) of Schedule L-17 or it's successor.

d) Unless specifically contradicted above, all other provisions of Rider L-17-EP, or its successor, remain in effect. The Authority, in its sole judgment, shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time.

f) This pricing alternative is in effect until modified or withdrawn. This pricing alternative is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted ______________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Supersedes: Schedule L-16-EP-AU,
Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
STANDBY SERVICE
RIDER L-17-SB

Section 1. Availability

(A) Service hereunder, "Standby Power", is available to those customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-17 or its successor (hereinafter, "Schedule L"), to which this Rider L-17-SB is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-17-SB, the sum of the Customer's Firm Contract Demand and Interruptible Contract Demand must equal or exceed 1,000 kW.

(C) Standby Power shall be that power used to provide standby or replacement service which, in the opinion of the Authority, the Authority has available at any location, to a Customer having another source of electrical power not held solely for emergency use, or another source of electrical power for peak-shaving purposes, both for which the Authority's service may be substituted directly or indirectly.

Section 2. Character of Service

(A) Standby Power hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L that (i) is in excess of Firm Power purchased by the Customer under Schedule L; and Interruptible Power, if any, purchased by the Customer under Rider L-17-I; and Economy Power, if any, purchased by the Customer under Schedule L-17-EP, and (ii) is deemed, in the opinion of the Authority, to be available for use by the Customer.

(B) The Customer shall use its best reasonable efforts to coordinate its requirements for Standby Service with the Authority, including (but not limited to) scheduling maintenance outages of Customer-owned generation to occur at times agreeable to the Authority. In no event shall the Authority be required to supply Standby Service at times when it shall have interrupted or curtailed service to any other retail customer. In no event shall the Authority be required to supply Standby Service on more than sixty (60) days out of any twenty-four (24) consecutive months.

Section 3. Monthly Rates and Charges

The monthly charge for Standby Power shall consist of the following charges:

(A) Monthly Standby Reservation Charge

The Monthly Standby Reservation Charge hereunder shall be equal to the Customer's Standby Power Contract Demand for such Billing Month, in kilowatts, times $3.66 per kilowatt.

(B) Monthly Standby Demand Charge

All kW of Standby Billing Demand @ $14.34/kW

(C) Monthly Energy Charge

The Monthly Energy Charge for Standby Power Service shall be calculated by multiplying the total amount of kilowatt-hours of Standby Power delivered to the Customer during the current month by the Monthly Standby Power Energy Rate for such month. The Monthly Standby Power Energy Rate for a month shall be the sum of (i) the Authority's Average Monthly Fossil Fuel Cost Rate and (ii) the Authority's then current Non-Fuel Energy Cost, both as hereinafter defined.

The Authority's Average Monthly Fossil Fuel Cost Rate for each month shall be determined by the following formula:

$$F = 100 * (Fm/Gm) * (1/(1-K)) * (1/(1-L))$$

where:

F = Average Monthly Fossil Fuel Cost Rate in cents per kilowatt-hour, rounded to the nearest one-thousandth of a cent.

Fm = the Authority's total dollar fossil fuel cost for the current month, which shall be equal to the sum of:

(a) the cost of fossil fuel burned or used, including the net cost of allowances expensed concurrent with regulated emissions, in the Authority's own plants and the Authority's share of fossil fuel burned or used in jointly owned or leased plants as such costs are recorded in Accounts 501, 509, and 547; plus

(b) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the authority to substitute for its own higher cost energy; plus

(c) the actual identifiable fossil fuel cost associated with energy purchased for reasons other than identified in (b) above; less

(d) the cost of fossil fuel recovered through inter-system sales including, without limitation, the fuel cost related to economy sales and other energy sold on an economic dispatch basis.

Gm = the Authority's fossil net generation, in kilowatt-hours, for the current month, which shall be equated to the sum of:

(a) the net generation of the Authority's own fossil-fueled plants and the Authority's shares of jointly owned or leased fossil-fueled plants; plus

(b) interchange in; plus

(c) the fossil-generated energy purchased by the Authority other than interchange; less

(d) the net fossil-fueled generation associated with inter-system sales referred to in Fm(d) above.

K = the Authority's allowance for capital improvements, which, for the purposes of this Rider, shall be nine percent (9.0%), expressed as a decimal fraction.

L = the Authority's allowance for transmission and distribution system losses applicable to service to the Customer, expressed as a decimal fraction.

The Authority's Non-Fuel Energy Cost shall be the rate, in cents/kWh, obtained by subtracting (a) the product of (i) 1/(1-K), where "K" is defined above, and (ii) the base fuel cost (Fb/Sb) contained in the Authority's then applicable Fuel Adjustment Clause (FAC) from (b) the Energy Charge set forth in the Authority's then applicable Large Light and Power Rate Schedule (Schedule L).

Section 4. Determination of Demands

(A) Standby Power Billing Demand

The Customer's Standby Power Billing Demand for each Billing Month shall be the amount, if any, by which the Customer's Measured Demand for such month, determined pursuant to Section 4(B) of Schedule L, exceeds the sum of (i) the Customer's then-current Firm Contract Demand, under Schedule L, and (ii) the Customer's Economy Power Contract Demand, if any, under Rider L-17-EP; provided however, that in no event shall such Standby Billing Demand be greater than the Customer's Standby Power Contract Demand. Any Measured Demand exceeding the Customer's total Contract Demand for such month shall be Excess Demand in accordance with Section 4(D) of Schedule L.

If a Customer fails to satisfy the requirements of Section 2(B) above, the Authority may, at its sole option, require the Customer to pay for all Standby Billing Demand at the rate specified in Section 3(A)(2)(a) of Schedule L, until such time as the Customer satisfies the constraints of Section 2(B) above.

(B) Standby Power Contract Demand

(1) Except as otherwise provided herein, the Customer's Standby Power Contract Demand shall be the maximum amount of Standby Power, in kilowatts, that the Customer has requested and the Authority has agreed to supply, as evidenced in the Delivery Point Specification Sheet for which the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer may reduce its Standby Power Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month periods, by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of the Service Agreement between the Customer and the Authority, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Standby Power Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Standby Power Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Standby Power Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Standby Power Contract Demand(s) for such years.

Notices of such reductions in the Customer's Standby Power Contract Demand shall be irrevocable once given.

(3) The Customer's Standby Power Contract Demand, once established or reduced, may be increased only by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(4) The total amount of Standby Power available for sale to all customers changes from time to time. In initially determining the amount of Standby Power, if any, to provide a Customer and/or in determining the amount, if any, by which a Customer's Standby Power Contract Demand may be increased, the Authority shall take into account the total amount of such Standby Power it reasonably expects to be available and its prior commitments for sales of such power. If, and to the extent that, the Authority thus determines it can make additional Standby Power available to new Customers and to existing Customers, the Authority shall do so on a first-come, first-served basis.

Section 5. Other Terms and Conditions

Service under this Rider L-17-SB, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted ___________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule L-16-SB, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
DEMAND RESPONSE BUY BACK (DRB)
SCHEDULE L-17-DRB

Section 1. Limited Availability

(D) Service hereunder, "Demand Response Buy Back," is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-17 or its successor (hereinafter, "Schedule L"). In addition, service hereunder shall be available only to specified Delivery Points upon a prior written Service Agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(E) In order to receive service under this Schedule:

1. The sum of the Customer's Contract Demand under this Schedule L-17-DRB plus the Customer's Firm Contract Demand must equal or exceed 1,000 kW,

2. The Customer's electrical wiring permits separate metering of the Customer's equipment and facilities,

3. The Customer's designated equipment and facilities must be totally and responsively interruptible at the direction of the Authority or its designated representatives,

4. The Customer, at its expense, shall cause the following to be installed:

   a) Dedicated telephone and data lines for the exclusive use of the Customer and the Authority,

   b) All communications and control equipment required by the Authority,

   c) Separate metering provided by the Authority to enable the Authority to separately meter the Customer's designated equipment and facilities.

5. The Customer agrees to hold the Authority and its designated representatives harmless from any and all claims, for damages resulting from interruption or curtailment of electric service provided under this Schedule. (See Section 7 - Special Provisions.)

(F) The total amount of Demand Response Buy Back service available to all qualifying customers shall be determined solely by the Authority and such amount changes from time-to-time. As of January 1, 2012, the Authority has determined that Demand Response Buy Back service will be made available to qualifying customers on a "first come first served" basis up to a maximum aggregate amount of 300 MW.

Section 2. Character of Service

Demand Response Buy Back hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L and Interruptible Service Rider L-17-I that is interruptible or curtailable by the direction of the Authority in accordance with the following terms:

(H) Demand Response Buy Back shall be interruptible or curtailable service with a short Customer notice and short interruption duration that is applicable to the Customer's equipment and facilities. Short notice will be two (2) minutes or less with usual customer notification and short duration will be limited to sixty (60) minutes from the onset of the interruption or curtailment.

(I) During a System Disturbance or Emergency, Demand Response Buy Back service shall typically be the first type of service to be interrupted or curtailed and interruption and curtailment will be ratably administered among Customers receiving such service as determined by the Authority (see Operational Guidelines for Curtailment and/or Interruption of Curtailable or Interruptible Loads).

(J) The Authority shall have the right, at any time or times and for any reason or reasons, to direct the interruption of all or part of the Demand Response Buy Back service, provided that the duration of such interruptions or curtailments is sixty (60) minutes or less, shall not exceed 200 hours, not occur in more than 60 days, in any calendar year and, provider further, that the number of interruptions or curtailments, other than during System Emergencies, shall not exceed two (2) in a calendar day. As used herein, a "System Disturbance or Emergency" means a condition on the Authority's system in which, in the sole judgment of the Authority's System Controller or designated representative, action is required to maintain compliance with approved Reliability Standards, or there is an imminent danger of deterioration of service to firm or higher priority customers, voltage collapse, or damage to a part of the system. The Authority shall establish and maintain operational guidelines (referenced above), which shall state the conditions and circumstances under which directions for interruptions and curtailments may be made. Such operational guidelines shall be published, and available for review, at the Authority's offices.

(K) When the Authority determines that a System Disturbance or Emergency is imminent or exists and/or determines the need to interrupt or curtail the Customer's Demand Response Buy Back service as provided herein, the Authority shall give notice thereof to the Customer by telephone or by such other means of communication as the Authority may from time-to-time designate. Each such notice shall specify a demand level of Demand Response Buy Back service, to which the Customer's use of Demand Response Buy Back service is to be limited and the anticipated time period (hereinafter, a "Curtailment Period") to which such limitation is to apply. After receiving such notice, the Customer shall, except as otherwise provided herein, reduce its use of power during the Curtailment Period to which the notice applied, to the level specified by the Authority. Each such notice shall be deemed received by the Customer if the Authority shall have issued or attempted to issue that notice.

(L) The Authority will use reasonable efforts to give as much advance notice as practicable of probable curtailments when circumstances permit. It is recognized that because of the Character of Service of this Schedule, Customer Notice by the Authority of a Demand Response Buy Back interruption or curtailment could be two (2) minutes or less and not more than ten (10) minutes prior to the expected initiation of the Curtailment Period.

(M) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period shall be classified as Excess Power and subject to penalties as set forth herein; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Power.

(N) Nominated demand for the Demand Response Buy Back service is not subject to the Authority's Demand Sales Adjustment Clause DSC-17, or its currently applicable successor clause, if any.

Section 3. Monthly Credits

For all Demand Response Buy Back service provided hereunder, the monthly credit for controlled load response during a Curtailment Period shall be based on a combination of the sum of Nominated Demand as specified by the Customer and the specified Monthly Credit ($/kW-month), and the sum of the Nominated Demand as specified by the Customer (regardless of the demand level requested by the Authority), the number of Curtailment Periods that have occurred within the billing period, and the specified Event Credit rate ($/Event per MW) as indicated below and, as follows:

(D) Monthly Credit

Nominated kW of Demand Response Buy Back Service……….……………..$(614.00)/MW

(E) Event Credit

For all service provided hereunder other than Excess Power, the Monthly Event Credit for Demand Response Buy Back Service shall be determined as follow:

1. Nominated MW of Demand Response Buy Back service ...._____ (MW)
2. Number of Curtailment Periods within billing period .... ______ (#)
3. Credit per Curtailment Period per MW .... $(307.00) ($/MW)
4. Total Credit (a * b * c) ....$____________

(F) Excess Power Charge

The price for Excess Power used by the Customer in each Curtailment Period shall be 200% of the Authority's reasonable best estimate of its incremental cost (including opportunity costs) of supplying such Excess Power and any penalties imposed on the Authority by the Regional and Sub-regional Reliability Councils and their Balancing Authority. Such incremental costs may include both demand-related and energy-related costs.

Section 4. Determination of Demands

The Customer's Demand Response Buy Back demand for each Delivery Point shall be established initially by mutual agreement of the Authority and the Customer, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and part of, the Service Agreement between the Customer and the Authority. The sum of the Customer's Demand Response Buy Back for each Delivery Point will serve as the basis for the Nominated MW of Demand Response Buy Back included in the calculation of the Monthly Credit in Section 3 above.

Section 5. Control Characteristics

(F) Frequency

The Control Conditions will typically result in less than twenty (20) Curtailment Periods per calendar year and will not exceed twenty (20) Curtailment Periods per calendar year.

(G) Notice

Notice for immediate customer action by the Authority of a Demand Response Buy Back interruption or curtailment could be two (2) minutes or less and not more than ten (10) minutes.

(H) Duration

The duration of a single Demand Response Buy Back Curtailment Period will be one (1) hour or less. Under typical circumstances, the Curtailment Period will not exceed one (1) hour.

(I) Major Disturbance

In the event of a major disturbance, as defined by the Authority, greater frequency, less notice, or longer duration than listed above may occur. In the event of a major disturbance, the Customer is not entitled to additional compensation beyond that indentified herein, regardless of greater frequency, less notice or longer duration. The Customer agrees that the Authority will not be liable for any damages or injuries that may occur as a result of the implications of a major disturbance, including, but not limited to, greater frequency, less notice (including no notice) or longer duration.

(J) Customer Responsibility

4. Upon the successful installation of the monitoring and load control equipment, a test of this communications and monitoring equipment will be conducted by the Authority. Testing will be conducted at a mutually agreeable time and date between Authority and Customer.

5. The Customer shall be responsible for providing and maintaining the appropriate equipment required to interrupt or curtail the Customer's load within the required time as specified by the Authority and upon receiving notice from the Authority, as specified in the Service Agreement between the Customer and the Authority.

6. The Authority will direct the interruption or curtailment of a portion or all of the Customer's Nominated Demand Response Buy Back service for up to a one (1) hour period once per year for testing purposes at a mutually agreeable time and date, if the Customer's load has not been successfully controlled during a load control event in the previous twelve (12) months. Testing purposes include the testing of the load control equipment to ensure that the Customer's load is able to be monitored by the Authority within the agreed upon specifications.

Section 6. Term of Service

Service under this Schedule shall continue, subject to Limitation of Availability, until terminated by either the Authority or the Customer upon written notice given at least five (5) years prior to termination. The Authority may terminate service under this Schedule at any time for the Customer's failure to comply with the terms and conditions of this Schedule or the Service Agreement. Prior to any such termination, the Authority shall notify the Customer at least thirty (30) days in advance and describe the Customer's failure to comply. The Authority may then terminate service under this Schedule at the end of the 30-day notice period unless the Customer takes measures necessary to eliminate, to the Authority's satisfaction, the compliance deficiencies described by the Authority. Notwithstanding the foregoing, if, at any time during the 30-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Authority shall be entitled to suspend forthwith the monthly credits under this Schedule.

Section 7. Special Provisions

(H) Monitoring of the Customer's load shall be accomplished through the Authority's use of monitoring circuits connected directly to the Customer's switching equipment of the Customer's load and may be controlled by use of other means acceptable to the Authority.

(I) The Customer shall grant the Authority reasonable access for installing, maintaining, inspecting, testing and/or removing Customer-owned communications and monitoring load control equipment.

(J) It shall be the responsibility of the Customer to determine that all of its electrical equipment to be controlled is in good repair and working condition. The Authority will not be responsible for the repair, maintenance, or replacement of the Customer's electrical equipment.

(K) The Authority will not be required to install load monitoring equipment if the installation cannot be economically justified.

(L) Credits under this Schedule will commence after the installation, inspection, and successful testing of the load monitoring equipment. Credits are applied to specific Curtailment Periods only, as requested by the Authority and responded to by the Customer.

(M) The Customer shall hold the Authority and its designated representatives harmless from any and all claims, actual or threatened, for economic or punitive damages including but not limited to life, safety, equipment, facilities product, inventory, and opportunity resulting from interruption or curtailment of electric service provided under this Schedule and the Service Agreement.

(N) Service under this Schedule is subject to the terms of the currently effective Schedule L and/or Schedule L - Interruptible, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Pricing for DRBB provided herein is in effect until modified or withdrawn. This pricing is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted [date]

Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule L-16-DRB, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
EXPERIMENTAL
LARGE LIGHT AND POWER
ECONOMIC DEVELOPMENT SERVICE
RIDER L-17_ED

SECTION 1. Availability:

(A) Service hereunder, "Economic Development Service" (hereinafter, "Rider) is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-17 or its successor (hereinafter, "Schedule L"), to which this Rider is attached and made a part of. In addition, service hereunder shall be available only to New Load.

(B) New Load, as used herein, is load that was not served by the Authority prior to the initial effective date of this Rider, and has been determined by the Authority as economic development of the Authority's service area in accordance with Section 1 (C), below. For existing Customers, New Load is the net incremental load (a) above that which existed and (b) was not served by the Authority under Schedule L or under riders L-17-I, L-17-EP, L-17-EP-O, and L-17-SB, or their successors, prior to the initial effective date of this Rider or, by load served directly from power and energy requirements purchased by a Wholesale Customer from the Authority. Wholesale Customers as used herein shall mean a municipal corporation, electric cooperative, or joint municipal power agency organized under the laws of the State of South Carolina that is a long-term, firm wholesale customer of the Authority. As used herein, New Load does not include: replacement electrical machines, equipment or processes; load shifted from one Delivery Point on the Authority's system to another on the Authority's system; load that existed and was served by another electric provider prior to that load being served by the Authority. All qualifying New Load for either a new or existing customer shall not exceed 40 MWs per customer per delivery point. Furthermore, the aggregate amount of New Load available to all Authority customers shall not exceed 300 MWs.

(C) Contribution of New Load to Economic Development: In order to receive service for this Rider, the "Customer" shall have:

iii. Requirements for service hereunder of at least 1,000 kW of load under this Rider (hereinafter "Firm-ED Load"), **and**;
iv. Must employ an additional workforce within the Authority's service area of a minimum of thirty-five (35) full time equivalent (FTE) employees per 1,000 kW demand of Firm-ED Load during the Contract Period, **or**, must result in a minimum capital investment within the Authority's service area of $500,000 per 1,000 kW demand of Firm-ED Load.

(D) Service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(E) This Rider is not available for renewal of service for a period of time following interruptions such as equipment failure, temporary plant shutdown, strike, or cessation of operations due to economic conditions. This period of time is the longer of either one year or the Notification Period as defined in individual customer contracts. However, if change of ownership occurs after the customer contracts for service under this Rider, the successor customer may be allowed to fulfill the balance of the contract under this Rider and continue to receive the discount as outlined in this Rider, subject to the eligibility requirements and other provisions hereof.

(F) This Rider is applicable and available to new applicants through December 31, 2014. Additionally, service hereunder is made available by the Authority on an experimental, pilot-program basis. Accordingly, the availability of such service, the terms and conditions thereof, and the operational aspects of such service are subject to termination or change, in whole or in part; provided, however, that this Rider will remain in effect for any Customer who has been approved to receive service.

SECTION 2. Character of Service:

Electric power and energy delivered shall be of the same character as that described in Section 2 of Schedule L, which is incorporated herein by reference.

SECTION 3. Monthly Billing Rates:

The charges for service hereunder shall consist of the following:

(A) Demand Charge:

The monthly Demand Charge per Firm-ED kW shall be determined as follows:

Demand Charge per Firm-ED kW = Schedule L Base Demand Charge – ED Discount

Where the ED Discount is determined by taking a percentage of the base demand charge as stated in the then-current Schedule L, whereas, the ED Discount is set forth in the following table:

Months 1 – 12	**45% of Schedule L Base Demand Charge**
Months 13 – 24	**30% of Schedule L Base Demand Charge**
Months 25 – 36	**20% of Schedule L Base Demand Charge**
Months 37 – 48	**10% of Schedule L Base Demand Charge**
After Month 48	**No Discount**

(B) Energy Charge:

Same as the Energy Charge per kilowatt-hour and Fuel Adjustment Charge in Rate Schedule L.

(C) All other monthly charges per Schedule L will apply.

SECTION 4. General Provisions:

Customer must make an application to the Authority for service of New Load under this Rider and Authority must approve such application before Customer may receive service hereunder. The application must include a description of the amount of and nature of the new or additional load and the basis on which the Customer qualifies as set forth in Section (1) above. In the application, Customer must affirm that availability of this Rider was a factor in Customer's decision to locate the New Load on Authority's system. The application shall also specify the total number of full time equivalent employees (FTE) employed by Customer in all establishments receiving electric service from Authority's system, at the time of application for this Rider, as well as the additional FTE attributed to the New Load. Alternatively, Customer must include a description of the minimum capital investment requirement,

including verification of the value of the declared capital investment. The Authority reserves the right to verify at any time during the Contract Period (as defined in Section 5) that the Customer satisfies the availability and eligibility requirements set forth in Section 1 hereof. Customer shall provide a statement to the Authority, verified by an officer of the Customer or their designee, that the Customer satisfies the availability and eligibility requirements of the Rider. This statement will be required annually during the Contract Period from the operational date of the new or expanded facility. The operational date of the new or expanded facility that results in New Load shall be no more than one year from date of application.

SECTION 5. Contract Period:

Each Customer shall enter into a Service Agreement to purchase electricity from the Authority for a minimum initial term of 8 years from the date the new or expanded facility is fully operational as declared by the Customer, herein defined as the Contract Period. Thereafter, either party can terminate the Service Agreement at the end of the initial Contract Period as provided in the terms and conditions of the then-applicable Schedule L. Service Agreement will include specified Contract Demand for Firm-ED Load which meets the requirements as stated in Section 1 of this Rider. An individual establishment and/or physical location will not be allowed to receive ED Discounts for more than four (4) years under this Rider, unless the Authority, at its sole discretion, agrees to accept and approve a new application and contract for qualifying New Load.

Discounts under this Rider shall begin no earlier than the operational date of the new or expanded facility and shall end 48 months after the later of (i) operational date of the facility, provided that such operational date shall be no more than one year after the application date, or, (ii) the date the Customer's first bill is rendered under this Rider.

If at any time during the term of contract under this Rider, Customer violates any of the terms and conditions of the Rider or the Service Agreement, Authority may discontinue service under this Rider without notice and bill Customer under the applicable schedule without further ED Discounts. In the event electric service is terminated or discontinued under this Rider by the Customer or the Authority, or the Contract Demand for Firm–ED is reduced by Customer before the end of the Contract Period, Customer shall pay Authority, in addition to all other applicable charges, the sum of all ED Discounts received, plus interest compounded annually, for the Firm-ED Load that will no longer be served by Authority. The rate of interest shall be the rate per annum which will be based on the then current LIBOR index. The Authority shall have the right to adjust the total payment required by the Customer, as previously described, at its sole discretion.

SECTION 6. Other Terms and Conditions:

Except as otherwise provided in this Rider, service hereunder shall be subject to all terms and conditions of the then-applicable Large Light and Power Rate Schedule L.

The Delivery Date is the first date service is supplied under the contract.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted ____________, 2015
Effective for bills rendered on and after April 1, 2017.

Supersedes:
Schedule L-16-ED, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
ECONOMIC DEVELOPMENT SALES ADJUSTMENT CLAUSE
(EDA-17)

Section 1. Purpose:

The Economic Development Rates (Riders L-13-ED-02 & L-14-ED-T) were approved by the Authority's Board of Directors on April 26, 2013 and April 25, 2014, respectively. The Economic Development Rate is available to customers who qualify that are directly served by the Authority as well as Wholesale Customers indirectly served by rider. Wholesale customers as used herein shall mean a municipal corporation, electric cooperative, or joint municipal power agency organized under the laws of the State of South Carolina that is a long-term, firm wholesale customer of the Authority. The purpose of this clause is to credit the Authority's firm-requirements and interruptible service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority from the direct and indirect sales associated with Economic Development Service Riders L-13-ED-02 & L-14-ED-T or their successors, or, associated Rider as provided in memorandum of understanding and agreement between the Authority and its customers, to the extent that such sales may not be reflected in the currently effective rates for such firm-requirements and interruptible service customers.

Section 2. Applicability:

The Economic Development Sales Adjustment Clause is applicable, to and becomes a part of, all of the Authority's published rate schedules that so specify.

Section 3. Adjustment of Bills:

Each customer's current monthly bill, as computed under the appropriate rate schedule, will be decreased by an amount equal to the result of multiplying (i) the appropriate rate "D" (as defined below), times (ii) either (a) in the case of each Large Light & Power ("Industrial") customer, that customer's current Firm Billing Demand and Interruptible Billing Demand, excluding L-13-ED-02 & L-14-ED-T Rate customers' load, or portions of load thereof, or (b) in the case of each Municipal Light & Power ("Municipal") customer, that customer's current Billing Demand, or (c) in the case of each other type of customer ("Distribution Service" customers), the total billed kWh of energy for the period to which the bill applies. Rate Riders L-13-ED-02 & L-14-ED-T Service customers, or portions of service thereof, are excluded from the Economic Development Sales Adjustment Clause during the period of the discount as defined in L-13-ED-02 & L-14-ED-T and specific to each customer's load or portion of customer's load thereof.

The rate D shall, for each respective customer class, be determined as follows:

$$D = R_D / B_D$$

Where:

D = The adjustment rate factor, in dollars per kW for Industrial and Municipal customers and in dollars per kWh for Distribution Service customers, in each case, rounded to the nearest one-thousandth of a cent.

R_D = The total demand-related or capacity-related revenues associated with Economic Development Riders L-13-ED-02 & L-14-ED-T for the preceding month allocated to the customer class (Industrial [as modified above], Municipal, or Distribution Service), based on the projected average four-month class coincident peak demand contributions for the current calendar year, as set forth in the Authority's then most recently adopted load forecast.

B_D = The projected total billing units for the customer class to which the adjustment rate factor, D, is to apply, for the current month, in kW for Industrial (as modified above) and Municipal customer classes and in kWh for Distribution Service customer classes.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule EDA-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
FUEL ADJUSTMENT CLAUSE
FAC-17

Applicability:

This Fuel Adjustment Clause is applicable to and becomes a part of each of the Authority's published Rate Schedules and rate riders thereto that so specify.

Adjustment of Bills:

Each monthly bill, computed under the appropriate Rate Schedule and appropriate rate riders, will be increased or decreased by an amount equal to the result of multiplying the measured or used kWh by the factor F, determined as follows:

$$F = (F_m/S_m - F_b/S_b) \times (1 / 1\text{-}K)$$

Where:

1. F = Adjustment factor in dollars per kWh rounded to the nearest one-thousandth of a cent.

2. F_m = Total fuel and purchased power cost for the three preceding months, consisting of the costs of:

   a. the cost of fossil, nuclear and renewable fuel consumed, including the net cost of allowances expensed concurrent with regulated emissions, in the Authority's own plants and the Authority's share of fossil, nuclear and renewable fuel consumed in jointly owned or leased plants, plus

   b. the actual identifiable fossil, nuclear and renewable fuel costs associated with energy purchased for reasons other than identified in (c) below, plus

   c. the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Authority to substitute for its own higher cost energy, less

   d. the cost of fossil, nuclear and renewable fuel recovered through inter-system sales and any applicable non-firm intra-system sales (such as Economy Power, Secondary Power), including the fuel costs recovered through economy energy sales and other energy sold on an economic dispatch basis.

3. S_m = kWh sales which shall be equated for the three preceding months to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) sales referred to in F_m (d) above, less (vi) average annual power supply transmission losses in decimal form times the net sum of (i), (ii), (iii), (iv), and (v) in this definition of S_m.

4. F_b/S_b = \$0.03641

Where:

a. F_b = Total estimated fuel cost in the base period.

b. S_b = Total estimated kWh sales for the base period.

5. K = Allowance for capital improvements and distribution losses, as set forth in each Rate Schedule and applicable rate riders to which this Clause applies.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule FAC-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
DEMAND SALES ADJUSTMENT CLAUSE
(DSC-17)

Section 1. Purpose:

The purpose of this Clause is to credit the Authority's firm-requirements and Interruptible Service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority through Non-Class Sales, to the extent that such sales may not be reflected in the currently effective rates for such firm-requirements customers. Such demand-related and capacity-related revenues shall mean charges recovered on a kilowatt (kW) or reservation basis as well as charges recovered through a kilowatt-hour (kWh) basis from Section c of rider L-17-EP-AU. As used herein, "Non-Class Sales" consist of (i) off-system, inter-utility sales, and (ii) non-firm, non-requirements, on-system sales (such as sales of Interruptible Power and Standby Power, pursuant to the Authority's Large Light & Power Rate Schedule and the currently effective riders thereto).

Section 2. Applicability:

The Demand Sales Adjustment Clause is applicable, to and becomes a part of, all of the Authority's published rate schedules that so specify.

Section 3. Adjustment of Bills:

Each customer's current monthly bill, as computed under the appropriate rate schedule, will be decreased (or, when applicable, increased) by an amount equal to the result of multiplying (i) the appropriate rate "D" (as defined below), times (ii) either (a) in the case of each Large Light & Power ("Industrial") customer, that customer's current Firm Billing Demand, or (b) in the case of each Municipal Light & Power ("Municipal") customer, that customer's current Billing Demand, or (c) in the case of each other type of customer ("Distribution Service" customers), the total billed kWh of energy for the period to which the bill applies. For Interruptible Service customers, Non-Class Sales are exclusive of non-firm sales specific to Interruptible Power.

The rate D shall, for each respective customer class, be determined as follows:

$$D = (R_m - R_b) / B_m$$

Where:

D = The adjustment rate factor, in dollars per kW for Industrial and Municipal customers and in dollars per kWh for Distribution Service customers, in each case, rounded to the nearest one-thousandth of a cent.

R_m = The total revenues from Non-Class Sales for the preceding month allocated to the customer class (Industrial, Municipal, or Distribution Service), based on the projected average four-month class coincident peak demand contributions for the current calendar year, as set forth in the Authority's then most recently adopted load forecast. For Interruptible Service customers, Non-Class Sales exclude non-firm sales specific to Interruptible Power.

R_b = The allocated revenues from Non-Class Sales, reflected in the currently effective rate(s) for the customer, which shall, for purposes of this Clause, be the following amounts:

e. For Firm Industrial customers: $58,000 per month beginning April 1, 2017.

f. For Interruptible Industrial customers: $120,000 per month beginning April 1, 2017.

g. For Municipal customers: $12,000 per month beginning April 1, 2017.

h. For Distribution Service customers: $303,000 per month beginning April 1, 2017.

B_m = The projected total billing units for the customer class to which the adjustment rate factor, D, is to apply, for the current month, in kW for Industrial and Municipal customer classes and in kWh for Distribution Service customer classes.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2017

Supersedes:
Schedule DSC-16, Effective April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
POLE ATTACHMENT
SCHEDULE PA-17

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable to all telephone companies, cable television and other such communication companies for the purpose of attaching their lines, cables, wireless or other non-linear devices to the Authority's distribution poles. When a telephone company and a cable company are affiliated, they shall nevertheless be treated as separate entities and will be billed separately for each attachment.

Section 3. Rates and Charges:

(E) Annual Pole Attachment Billing Rate

1. The annual charge for service hereunder shall be $14.60 for each attachment for each year (or portion of a year).

(F) Monthly Energy Charge

1. Customers shall be responsible for any electrical energy consumption in kilowatt-hours of its attachments and/or associated communication equipment, based on the full power ratings of said devices/equipment.

2. Energy Charge:
   a) Base Energy Charge:
      All kWh ……………………………………………………………………$0.1010/kWh

(G) Fuel Adjustment Clauses

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-17, or its currently applicable successor clause, if any, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(H) Taxes

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above annual rate. The charges computed at the above rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Payment:

Joint attachment bills will be rendered annually on a net basis. Energy bills (when applicable) will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased by the greater of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges.

Section 5. Terms and Conditions:

(C) Linear Pole Attachment:

In order to receive service hereunder, the Customer shall be required to enter into a contract with the Authority in the form Attachment A hereto (Linear Pole Attachment Service Agreement), which shall govern the provision of such service by the Authority and the use of such service by the Customer.

(D) Non-Linear Pole Attachment:

In order to receive service hereunder, the Customer shall be required to enter into a contract with the Authority in the form Attachment B hereto (Non-Linear Pole Attachment Service Agreement), which shall govern the provision of such service by the Authority and the use of such service by the Customer.

Adopted _______________, 2015
Effective for bills rendered on and after April 1, 2017.

Supersedes: Schedule PA-16, April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
Service Agreement
For
Linear Pole Attachment Service

This Agreement made and entered this ______ day of _____________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and ________, hereinafter referred to as the "Customer".

1. The parties hereby terminate any and all prior agreements providing for the attachment of the Customer's communication facilities to the Authority's poles.

2. Whenever during the term of this agreement the Customer wishes to install any of its wires or appurtenances upon any poles of the Authority, the Customer shall give written notice of such intention to the Authority, identifying the poles and describing the facilities it wishes to install thereon. As soon as reasonably possible after receipt of such notice the Authority shall, in writing, either consent to such installation or refuse such consent, but such consent shall not be unreasonably withheld.

3. If the Authority consents to such use, the Customer shall have the right to install and maintain its facilities on said poles at the locations and in the manner specified by the Authority, in accordance with the terms and provisions herein contained, and shall pay the annual charge contained in the Authority's Pole Attachment Schedule PA-17 or successor schedules.

4. The Customer shall provide the Authority prompt written notice of the removal of any wires and appurtenances from the Authority's poles, identifying the poles and describing the facilities removed.

5. (A) All installation, attachments, operations and maintenance of the Customer's facilities shall comply with all federal, state and local regulations, including, but not limiting the generality of the foregoing, the requirements set forth in the American National Standards, ANSI C2-2012 entitled "National Electric Safety Code" or such successor publication.

   (B) In addition to paragraph (A), all employees, agents or contractors of the Customer shall comply with the following requirements:

   1. Such employees, agents or contractors shall not approach nearer than five (5) feet to any energized electric circuit.
   2. Electrical hard hats shall be worn by all workers.
   3. All ladders must have safety straps.
   4. All employees, agents or contractors shall be properly secured while working from ladders or buckets.
   5. All employees, agents or contractors shall be sufficiently trained by the Customer to identify electric supply circuits in order to maintain required clearances, and the Customer shall, upon request, provide the Authority a certified copy of its safety training program.

6. (A) On the first day of January of each year of the term of this agreement, the Customer shall pay to the Authority the annual charge contained in the Authority's Pole Attachment Schedule PA-17 or successor schedules for each attachment used in any way by the Customer during the preceding calendar year, or any portion thereof.

   (B) The annual charge may be changed by the Authority from time to time and when so changed shall become effective at the time designated by the Authority and the annual charge for each calendar year in which there is such a change shall be prorated.

7. All of the Customer's facilities and property shall be installed, removed and maintained at the sole cost,

risk and expense of the Customer. The Customer shall, at any time, at its own cost, risk and expense, upon written notice from the Authority, change, alter, improve, or renew it installations and facilities covered hereby in such manner as the Authority may direct.

Should it become necessary at any time to change the location of any of the Customer's wires, cables, or other facilities from one position to another, such work may be done by the Authority at the sole cost, risk and expense of the Customer. The Customer shall not at any time make any changes in the location of its attachments to, or in the use of, the Authority's poles or facilities, without the written consent of the Authority.

8. (A) The Customer agrees to indemnify and hold the Authority harmless from the consequences of any property loss or damage, death or personal injury whatever, accruing or suffered or sustained from or by reason of an act, neglect or default of the Customer, its agents, servants or employees, in or about or in connection with the exercise of such attachment rights, or which may, in any manner or to any extent be attributable thereto, or to the presence of any property of the Customer upon the Authority's poles and whether or not acts, neglect or defaults on the part of the Authority, it agents, servants, or employees may have contributed to such loss, injury or damage, except that the Customer shall not be held responsible under this Agreement, for any loss of life, or personal injury or property damage accruing solely from the Authority's, its agents', servants', or employees' own negligence, without fault of the Customer, its agents, servants or employees.

   (B) Prior to the taking of any action with respect to any claim for loss or damage sustained as a result of the joint use of poles with claim for loss or damage is covered by the provisions of this Agreement, the Authority or the Customer, as the case may be, shall immediately upon being notified of the existence of such claim, notify the other party in writing of such claim and all particulars with respect thereto. In cases in which liability for such claim would, if proven, require the Customer to indemnify the Authority under this Agreement, the Authority shall make no settlement or disposition of such claim without written approval of the Customer. Should the Customer and the Authority disagree concerning the liability for any particular claim for which the Customer would have to indemnify the Authority under this Agreement, the Customer may defend against such claim in any action at law or equity, the cost of such defense litigation to be borne solely by the Customer. The Customer's obligation to indemnify the Authority shall not arise until after final disposition by lawful authority of the liability for any claim so defended against. The Authority agrees to cooperate fully with the Customer in the defense of any such claims. Where both the Authority and the Customer dispute any claim for loss or damage arising from the joint use of poles, the Customer and the Authority agree to jointly defend against any claim for loss or damage sustained as a result of the joint use of poles, the cost of such litigation, if successful, to be borne equally by the parties.

9. The Authority makes no warranty as to its title or rights to any of the property herein referred to and only grants the rights to set out in this instrument insofar as the Authority's rights and titles extend. Nothing herein contained shall be construed as a representation or guarantee by the Authority to the Customer of permission from municipal or other public authorities or property owners for the exercise of any of the rights herein described or referred to. The Customer shall not assign, transfer, sublet or otherwise alienate any of the rights or privileges herein granted without the written approval of the Authority.

10. Either party may terminate this Agreement at any time by giving ninety (90) days advance written notice of such intention to the other party.

11. In addition to the right of termination contained in Section 10 hereof, the Authority in its discretion may at any time or times immediately terminate the use by the Customer on any or all attachments covered by this Agreement for any of the following causes:

    (1) Installation, maintenance, or operation of facilities by the Customer at locations or positions on the Authority's poles other than those specified by the Authority or in a manner different from that so specified.

(2) Installation, maintenance, or operation of facilities by the Customer, in any way impairing, endangering or otherwise adversely affecting the system of the Authority.

(3) Objection or prohibition by municipal or any other public authorities, or by property owners, of or to any use of the Customer of the rights herein granted.

(4) The failure of the Customer to comply with any of the terms or provision of this Agreement.

Upon written notice by the Authority to the Customer that any of the above listed causes has arisen, the Customer shall forthwith remove, at its own expense, all of its facilities from any pole or poles as may be directed in said notice.

12. In the event that the Authority relocates its lines or poles, on which attachments of the Customer are located, it shall give prior notice of such intention to the Customer and, at the Customer's sole expense, the Customer may reattach its facilities to the relocated poles under the same conditions in their original locations.

If the Authority wishes to remove any pole or poles because of discontinuance of use by it of all or part of a line or lines, it shall have the right to do so notwithstanding the use thereof by the Customer. Where any such pole or poles are being used by the Customer, advance notice of the removal thereof shall be given to the Customer and the Customer shall remove its attachments from said pole or poles at its own expense and make any provisions necessary for the operation of its lines in such locations without any responsibility therefore by the Authority.

In either event, should the Customer fail to remove its attachments within the ninety (90) days after notification, the Authority shall have the right to remove or cause to be removed such attachments at the Customer's expense.

13. In cases where sufficient pole space for the Customer's attachment is not available on the Authority's poles, the Customer will pay the Authority all costs for installing a new pole of sufficient height less the salvage value of the pole replaced but including the cost of removal of the replaced pole.

14. In the event of any termination of the Agreement by either party under the terms of Section 10 hereof, or any termination by the Authority of the use of any pole or poles in accordance with Section 11 hereof, or the relocation or removal of lines or poles under Section 12 hereof, if the Customer fails to remove its facilities from any or all of the Authority's poles or systems covered by this Agreement, the Authority shall have the right to remove or cause to be removed the same, and the Customer shall pay to the Authority all costs and expenses of any such removal.

15. It is specifically understood by Customer that restoration of service which has been disrupted by any reason whatsoever shall be restored at the Authority's lowest priority level. Where multiple parties are involved in emergency restorations, access to the Authority's poles will be controlled by the Authority.

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed and their corporate seals to be hereunto affixed by their proper officers thereunto duly authorized as of the date hereinabove mentioned.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ______________________________	**BY:** ______________________________
ATTEST:	**(CUSTOMER)**
BY: ______________________________	**BY:** ______________________________

Adopted _________________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes: Attachment A, April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
Service Agreement
For
Non-Linear Pole Attachment Service

This Agreement made and entered this ______ day of ______________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and ___________________________, hereinafter referred to as the "Customer".

2. Prior to installing any facilities, Customer shall submit written notice of intent to install to the Authority, identifying the poles and describing the facilities it wishes to install thereon. Upon review of the written notice of the intent to install, the Authority shall either accept or decline the proposal, and provide Customer with written notice of its decision, which shall constitute the initial installation of facilities ("Initial Installation"). Whenever during the term of this agreement Customer wishes to install additional facilities upon any poles of the Authority, Customer shall give written notice of such intention to the Authority, identifying the poles and describing the facilities it wishes to install thereon. As soon as reasonably possible after receipt of such notice the Authority shall, in writing, either consent or refuse such request. The Authority retains the right to limit the number of facilities installed pursuant to this agreement.

2. If the Authority consents to such use, Customer shall have the right to install and maintain its facilities on said poles at the locations and in the manner specified by the Authority, in accordance with the terms and provisions herein contained, and shall pay the annual charge recited herein. The Authority reserves the right to specify any devices, adapters, circuit breakers, fuses, conductors, and so forth used to derive a source of power from its facilities. An installation drawing for the power supply configuration may be prescribed by the Authority as it deems necessary.

3. Customer shall provide the Authority prompt written notice of the removal of any facilities from the Authority's poles, identifying the poles and describing the facilities removed.

4. All installation, attachments, operations and maintenance of Customer's facilities shall comply with all federal, state and local regulations, including, but not limiting the generality of the foregoing, the requirements set forth in the American National Standards, ANSI C2-2012, entitled "National Electric Safety Code" or such successor publication. All employees, agents or contractors of Customer shall comply with the following requirements:

    8. Such employees, agents or contractors shall not approach nearer than five (5) feet to any energized electric circuit.

    9. Electrical hard hats shall be worn by all employees, agents or contractors.

    10. All ladders must have safety straps.

    11. All employees, agents or contractors shall be properly secured while working from ladders or buckets.

    12. All employees, agents or contractors shall be sufficiently trained by Customer to identify electric supply circuits in order to maintain required clearances, and Customer shall, upon request, provide the Authority a certified copy of its safety training program.

13. All equipment shall have a company logo affixed allowing utilities and others to readily identify Customer as the owner.

14. Any cords, cables, and conduits shall be securely strapped in a workmanlike manner.

5. On the first day of January of each year of the term of this agreement, Customer shall pay to the Authority the annual charge contained in the Authority's Pole Attachment Schedule PA-17 or successor schedules for each attachment used in any way by Customer during the preceding calendar year, or any portion thereof. In addition to the annual charge, Customer shall be responsible for the electrical energy consumption in kilowatt-hours of its devices and/or associated communication equipment, based on the full power ratings of said devices/equipment, and shall be billed in accordance with the annual charge contained in the Authority's Pole Attachment Schedule PA-17 or successor schedules

6. All of Customer's facilities and property shall be installed, removed and maintained at the sole cost, risk and expense of Customer. These costs shall include any and all assistance provided by the Authority for the installation of said facilities. Customer shall, at any time, at its own cost, risk and expense, upon written notice from the Authority, change, alter, improve, or renew its installations and facilities covered hereby in such manner as the Authority may direct. Customer shall not at any time make any changes in the location of its attachments to, or in the use of, the Authority's poles or facilities, without the written consent of the Authority.

   The Authority will not undertake the relocation or transfer of Customer's facilities on an Authority Pole, except in the event of emergency repair situations where the Authority's Pole or Customer's facilities are damaged. In such cases, Authority will reserve the right to transfer Customer's facilities that are still attached to the Authority's Pole, remove the damaged pole, leave the repair/replacement work for Customer, and bill Customer the actual costs incurred to perform the Attachment and/or Facility transfer of Customer's facilities.

7. Customer agrees to indemnify and hold the Authority harmless from the consequences of any property loss or damage, death or personal injury whatsoever, accruing or suffered or sustained from or by reason of an act, neglect or default of Customer, its agents, contractors, servants or employees, in or about in connection with the exercise of such attachment rights, or which may, in any manner or to any extent be attributable thereto, or to the presence of any property of Customer upon the Authority's poles and whether or not acts, neglect or defaults on the part of the Authority, its agents, servants, or employees may have contributed to such loss, injury or damage, except that Customer shall not be held responsible under this Agreement for any loss of life, or personal injury or property damage accruing solely from the Authority's, its agents', servants', or employees' own negligence, without fault of Customer, its agents, servants or employees.

   Prior to the taking of any action with respect to any claim for loss or damage sustained as a result of the joint use of poles with claim for loss or damage is covered by the provisions of this Agreement, the Authority or Customer, as the case may be, shall immediately upon being notified of the existence of such claim, notify the other party in writing of such claim and all particulars with respect thereto. In cases in which liability for such claim would, if proven, require Customer to indemnify the Authority under this Agreement, the Authority shall make no settlement or disposition of such claim without written approval of Customer. Should Customer and the Authority disagree concerning the liability for any particular claim for which Customer would have to indemnify the Authority under this Agreement, Customer shall defend against such claim in any action at law or equity, the cost of such defense litigation to be borne solely by Customer. The Authority agrees to cooperate fully with Customer in the defense of any such claims. Where both the Authority and Customer dispute any claim for loss or damage arising from the joint use of poles, Customer and the Authority agree to jointly defend against any claim for loss or damage sustained as a result of the joint use of poles, the cost of such litigation, if successful, to be borne equally by the parties.

8. Nothing herein contained shall be construed as a representation or guarantee by the Authority to Customer of permission from municipal or other public authorities or property owners for the exercise of any of the rights herein described or referenced. Customer agrees to obtain at its sole expense, all permits, approvals, licenses, conveyances, reliances, easements and authorizations from any and all State, Federal and Local Governmental agencies, and from any and all third parties, which may be necessary or desirable for the installation and maintenance of Customer's facilities. Customer shall not assign, transfer, sublet or otherwise alienate any of the rights or privileges herein granted without the written approval of the Authority.

9. Either party may terminate this Agreement at any time by giving ninety (90) days advance written notice of such intention to the other party. Upon termination, Customer shall pay to the Authority all amounts due and owing under this agreement, including but limited to any unpaid or unbilled annual charges.

10. In addition to the right of termination contained in Section 9 hereof, the Authority in its discretion may at any time or times immediately terminate the use by Customer on any or all attachments covered by this Agreement for any of the following causes:

    i. Installation, maintenance, or operation of facilities by Customer at locations or positions on the Authority's poles other than those specified by the Authority or in a manner different from that so specified.

    ii. Installation, maintenance, or operation of facilities by Customer, in any way impairing, endangering or otherwise adversely affecting the system of the Authority.

    iii. Objection or prohibition by municipal or any other public authorities, or by property owners, of or to any use of Customer of the rights herein granted.

    iv. The failure of Customer to comply with any of the terms or provision of this Agreement.

    Upon written notice by the Authority to Customer that any of the above listed causes has arisen, Customer shall forthwith remove, at its own expense, all of its facilities from any pole or poles as may be directed in said notice.

11. In the event that the Authority relocates its lines or poles, on which attachments of Customer are located, it shall give prior notice of such intention to Customer and, at Customer's sole expense, Customer may reattach its facilities to the relocated poles under the same conditions in their original locations.

    If the Authority wishes to remove any pole or poles because of discontinuance of use by it of all or part of a line or lines, it shall have the right to do so notwithstanding the use thereof by Customer. Where any such pole or poles are being used by Customer, advance notice of the removal thereof shall be given to Customer. Customer shall have the right to purchase the pole or poles at the higher of the pole's (1) then-value, in-place cost, or (2) net salvage value. Customer will indemnify and save harmless the Authority from any obligation, liability, cost, or charge incurred for the pole after the transfer of title of the pole to Customer. If Customer does not purchase the pole or poles, Customer shall remove its attachments from said pole or poles at its own expense and make any provisions necessary for the operation of its lines in such locations without any responsibility therefore by the Authority.

    In either event, should Customer fail to remove its attachments within ninety (90) days after notification, the Authority shall have the right to remove or cause to be removed such attachments at Customer's expense.

12. In cases where sufficient pole space for Customer's attachment is not available on the Authority's poles, Customer will pay the Authority all costs for installing a new pole of sufficient height less the salvage value of the pole replaced but including the cost of removal of the replaced pole.

13. In the event of any termination of the Agreement by either party under the terms of Section 9 hereof, or any termination by the Authority of the use of any pole or poles in accordance with Section 10 hereof, or the relocation or removal of lines or poles under Section 11 hereof, if Customer fails to remove its facilities from any or all of the Authority's poles or systems covered by this Agreement, the Authority shall have the right to remove or cause to be removed the same, and Customer shall pay to the Authority all costs and expenses of any such removal.

14. It is specifically understood by Customer that restoration of service which has been disrupted by any reason whatsoever shall be restored at the Authority's lowest priority level. Where multiple parties are involved in emergency restorations, access to the Authority's poles will be controlled by the Authority**.**

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed and their corporate seals to be hereunto affixed by their proper officers thereunto duly authorized as of the date hereinabove mentioned.

ATTEST: **SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**

BY: ______________________________ **BY:** ______________________________

ATTEST: **(CUSTOMER)**

BY: ______________________________ **BY:** ______________________________

Adopted ______________________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes: Attachment B, April 1, 2016

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
DISTRIBUTED GENERATION RIDER (RETAIL)
RIDER DG-17

Section 1. Availability:

(A) Service hereunder is available on a first-come, first-served basis to residential and non-residential Customers receiving concurrent retail electric service from the Authority who independently install and operate a distributed generation system to supply a portion of their energy requirements. The total installed capacity of all leased and owned distributed generation facilities shall not exceed two percent of the previous five-year average of the residential and commercial customer class contribution to coincident retail peak demand, after which service under this Rider will no longer be available to new customers. Service hereunder shall be available only upon the approval of the Authority.

Section 2. Applicability:

(A) This Rider is applicable to all residential and non-residential customers in the retail service area of the Authority and shall be limited to Customers receiving concurrent service from the Authority where a photovoltaic or other qualifying generation source of energy as determined by the Authority is installed on the Customer's side of the delivery point, hereinafter the "Customer-Generator", for the Customer's own use, interconnected with and operated in parallel with the Authority's distribution system. Upon a Customer's installation of a qualifying generation source of energy other than a photovoltaic system, the Authority reserves the right to adjust the effective Standby Charge as listed in Section 4(A)(2) as appropriate.

(B) This Rider is only applicable for installed single-phased generation systems that comply with the Authority's then current Standard for Interconnecting Customer-Owned Small Generation hereinafter the "Interconnection Standard", which may be modified by the Authority as deemed necessary. The Nameplate Rating of the Customer's installed generation system and equipment must not exceed the lesser of 20 kW if a residential customer, 1,000 kW if non-residential customer, or the estimated maximum monthly kilowatt (KW) demand. The Customer must comply with the liability insurance requirements of the Interconnection Standard and submit an application to interconnect which must be accepted by the Authority. The Customer agrees to pay an application fee in accordance with the Interconnection Standard and any costs associated with upgrades required to maintain a safe and reliable distribution system.

Section 3. Character of Service:

(A) On an hourly basis, the Authority shall measure the energy delivered to the Customer by the Authority and the energy generated by the Customer-Generator and delivered to the Authority. In each hour, the measured energy generated by the Customer-Generator and delivered to the Authority will be subtracted from measured energy delivered to the customer by the Authority. This calculation will determine the customer's net energy usage. In hours in which the customer's net energy usage is less than zero, the resulting value will be multiplied by the effective Energy Credit as stated in Section 4(A)(3); and in hours in which the Customer's net energy usage is greater than zero, the resulting value will be multiplied by the effective Energy Charge as stated in Section 4(A)(4). To produce a monthly bill, all hourly credits and charges will be summed, and added to other metering, demand, standby charges, and/or applicable taxes and other charges as set forth in the applicable rate schedule or as identified herein. Such a combination of charges and credits may not result in a monthly bill below the monthly Minimum Charge as set forth in Section 4 (C) herein below. Charges or credits will be determined using the appropriate seasonal energy charges and other charges as set forth in Section 4 (A) herein below. If after the Customer's payment of the monthly Minimum Charge a Customer's bill for the month results in a net credit to the Customer, the Authority will issue the credit in the form of a check if it is greater than or equal to $50.00. If the credit is less than $50.00, then it will be applied to the next billing month.

(B) The Authority will furnish, install, own and maintain metering to measure the kilowatt demand delivered by the Authority to the Customer, and to measure the net kilowatt-hours purchased by the Customer or delivered to the Authority. The Authority shall have the right to install special metering and load research devices on the Customer's equipment and the right to use the Customer's telephone line for communication with the Authority's and the Customer's equipment.

(C) If the Customer is not the owner of the premises receiving electric service from the Authority, the Authority shall have the right to require that the owner of the premises give satisfactory written approval of the Customer's request for service under this Rider.

(D) The Authority reserves the right to terminate the Customer's service under this Rider at any time upon written notice to the Customer in the event that the Customer violates any of the terms or conditions of this Rider or the Interconnection Standard, or operates the generation system and equipment in a manner which is detrimental to the Authority or any of its customers.

(E) While receiving service from the Authority under this Rider, the Customer-Generator may retain ownership of any Renewable Energy Credits produced by the Customer-Generator's system. The Authority reserves the right to adjust this Section 3 (E) regarding the ownership of Renewable Energy Credits at its discretion in the future.

(F) Due to the experimental nature of this Rider, the Authority may deem it necessary to re-evaluate this Rider and, as with all schedules, reserves the right to revise, eliminate, or close this Rider to new customers; provided, however, that this Rider shall not be closed prior to December 31, 2020 to any existing Customer receiving service under this Rider.

Section 4. Monthly Rates & Charges:

(A) Basic Monthly Charges:

(1) Metering Charge:
For each month, a charge of ……………………………………………………$9.00

(2) Stand-By Charge:
For each kW of installed capacity, a monthly charge of:
c) Residential ……………………………………………………………$4.70
d) Commerical ……………………………………………………………$5.00

(3) Energy Credits:

All kWh during the Summer Season $0.0416/kWh

All kWh during the Non-Summer Season $0.0384/kWh

Summer Season – The Summer Season energy credit shall apply to all kWh delivered from the Customer-Generator to the Authority for bills rendered during the months of June, July, August and September. Energy credits for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh delivered from the Customer-Generator to the Authority for bills rendered in months other than the Summer Season.

(4) Energy Charges:
As set forth in the applicable rate schedule.

(E) Adjustments to Energy Credits:

The Energy Credits shall be adjusted at least annually to reflect changes in the Authority's determination of its projected cost of energy.

(F) Minimum Charge:

The monthly minimum charge shall be the "CRTstomer Charge" as determined by the applicable rate schedule plus the "Metering Charge" plus any applicable "Stand-By or Demand Charges". Customers taking service under any demand-metered rate schedules shall be exempt from Stand-By Charges.

(G) Taxes:

Amounts for "payments in lieu of taxes", as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fee, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within 15 days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($.50) or two percent (2%) of the amount then outstanding including late payment charges.

Section 6. Terms and Conditions:

Service hereunder is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2017

Supersedes:
Schedule DG-16, Effective April 1, 2016

APPENDIX B

2018 RATE SCHEDULES

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL
GENERAL SERVICE
SCHEDULE RG-18

Section 1. Availability:

This schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable for use in private residences, single-family dwelling units, and farms. Energy and power delivered to each residence, dwelling unit, or farm shall be separately metered, and shall include energy used for incidental, non-commercial purposes (e.g., swimming pools, garages, and workshops). This Schedule is not applicable to recognized boarding or rooming houses or commercial establishments. Energy taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $21.00

(2) Energy Charge:

(i) Base Energy Charge:

Summer Season $0.1194/kWh

Non-Summer Season $0.0994/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(j) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and, 0.125 respectively.

(k) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(l) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 6. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _______, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Residential General Service RG-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL
TIME-OF-USE RATE
SCHEDULE RT-18

Section 1. Availability:

Service hereunder is available, on a voluntary basis, as a pilot program, to residential customers in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. The availability of service under this rate schedule shall be limited to the first 300 customers requesting service during the pilot period.

Section 2. Applicability:

This Schedule is applicable to private residences, single family dwelling units, and farms. Energy delivered to each residence, dwelling unit, or farm shall be separately metered, and shall include energy used for incidental, non-commercial purposes (e.g., swimming pools, garages and workshops). This Schedule is not applicable to recognized boarding or rooming houses or commercial establishments. Energy taken under this Schedule may not be resold or shared with others.

"The Authority, at its sole option, may place under this Schedule RT-18 Customers having tankless electric water heaters or other types of loads that are estimated by the Authority to have an annual load factor less than 35%. If at the Authority's option a Customer is placed on this Schedule RT-18 and after twelve consecutive months of service the Customer's annual load factor is greater than or equal to 35%, then the Authority shall remove the Customer from the Schedule RT-18 and credit or debit the Customer's usage for the previous twelve month period for any difference in billing under the Schedule RT-18 and the then applicable residential schedule."

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of…………………………………………………..$30.00

(2) Energy Charge:

(a) Base Energy Charge:

All kWh during the Summer On-Peak Hours $0.3520/kWh

All kWh during the Non-Summer On-Peak Hours $0.3168/kWh

All kWh during Off-Peak Hours $0.0633/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of On-Peak and Off-Peak Hours:

Summer period On-Peak Hours shall mean the hours from 1:00 p.m. to 7:00 p.m., Monday through Friday, for the months of June, July, August, and September, excluding Memorial Day, Independence Day and Labor Day.

Non-Summer period On-Peak Hours shall mean the hours from 6:00 a.m. to 10:00 a.m., Monday through Friday, for the months of December, January, and February, excluding Christmas Day, and New Year Day.

Off-Peak Hours are defined as all hours not specified above as On-Peak hours.

Section 6. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 7. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect, which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule RT-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
RESIDENTIAL TRANSITION ADJUSTMENT
SCHEDULE R-TA-18

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all residential users of energy and power as of April 1, 2016 receiving service pursuant to discontinued RN and RR Rate Schedules which included discounts for residences meeting certain energy efficiency standards. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, at the Authority's option, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Limitation of Service:

During the course of a comprehensive review of rates and charges, it was determined that approximately 11,000 active customers are taking service under Rate Schedules RN-13 & RR-13 which have been approved for termination. Beginning April 1, 2016, the Authority will systematically transition existing customers receiving service pursuant to RN-13 and RR-13 to the appropriate Residential General Service Rate Schedule.

The appropriate Residential General Service Rate Schedule will be Schedule RG-16 and its Successor Rate Schedules, or other then appropriate, applicable Residential Rate Schedules. To the extent a customer maintains active service during the transition period, the Transition Adjustment as described in Section 5, (A), (3), will apply. However, should a customer during the transition period terminate service, any new service at that premise shall have the option of the Residential General Service Schedule RG or the Residential Time-of-Use Rate Schedule RT.

The transition period shall consist of a three-year period commencing on April 1, 2016. Applicable credits will be reduced at a rate of 33.33% each year until this Transition Adjustment Schedule R-TA is equal to the then-current Residential General Service Schedule RG.

Section 5. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $21.00

(2) Energy Charge:

(i) Base Energy Charge:

Summer Season $0.1194/kWh

Non-Summer Season $0.0994/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(j) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and, 0.125 respectively.

(k) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(l) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(3) Transition Adjustment:

The charges for Schedule R-T8-16 will be determined by applying the following credits to the charges described in Section 5, (A), (1) and 5, (A), (2).

	R1 Standard Plus		R2 Standard		R3 Standard Plus (Improved)		R4 Standard (Improved)	
	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)	Monthly Credit ($/Month)	Energy Credit ($/kWh)
Year 1	$ 8.00	$ 0.0042	$ -	$ 0.0042	$ 5.50	$ 0.0015	$ -	$ 0.0015
Year 2	$ 4.00	$ 0.0021	$ -	$ 0.0021	$ 2.75	$ 0.0008	$ -	$ 0.0008
Year 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid.

Section 7. Terms and Conditions:

Service hereunder is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _______, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule R-TA-17 Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE
SCHEDULE GA-18

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power having no more than a 50 kW potential demand in any three months of any twelve consecutive months, for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $27.50

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1121/kWh

Non-Summer Season $0.0921/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 6. Period of Contract:

The Contract Period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 7. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule GA-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE DEMAND
SCHEDULE GB-18

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge

For each month, a charge of $26.00

(2) Demand Charge:

All kW of Billing Demand $23.60/kW

(3) Energy Charges:

(c) Base Energy Charge:

Summer Season $0.0475/kWh

Non-Summer Season $0.0375/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) <u>Minimum Charge</u>:

The minimum charge for single-phase service shall be the Customer Charge plus the Demand Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) <u>Taxes</u>:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

<u>Section 5. Determination of Demands</u>:

(A) <u>Measured Demand</u>:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period or (ii) thirty percent (30%) of the greatest Measured Demand computed for the preceding eleven months.

Section 6. Payment:

All bills are due and payable at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill shall be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including late payment charges on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 7. Metering:

Power and energy shall be metered at the point of delivery by the Authority.

Section 8. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule GB-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
SEASONAL GENERAL SERVICE
SCHEDULE GV-18

Section 1. Availability:

This Schedule is available, on a voluntary basis, in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all commercial customers of the Authority meeting the eligibility requirements of the Authority's General Service Demand Rate Schedule, or its successor. Service hereunder applies to all service of the same voltage and character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage of the Authority, and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of.. $26.00

(2) Demand Charge:

All kW of Billing Demand $25.74/kW

(3) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.0475/kWh

Non-Summer Season $0.0375/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing

purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the Measured Demand for the current billing period.

Section 6. Payment:

All bills are due and payable at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill shall be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including, late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 7. Metering:

Power and energy shall be metered at the point of delivery by the Authority.

Section 8. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule GV-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
GENERAL SERVICE
TIME-OF-USE RATE
SCHEDULE GT-18

Section 1. Availability:

This Schedule is available on a voluntary basis in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability

This Schedule is applicable to all commercial customers of the Authority meeting the eligibility requirements of the Authority's General Service Schedules, or their successor. Service hereunder applies to all service of the same voltage and character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase, as available, at available voltage of the Authority at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $31.00

(2) Demand Charges:

(a) All kW of On-Peak Billing Demand $25.96kW

(b) All kW of Off-Peak Billing Demand $14.58/kW

(3) Energy Charges:

(a) Base Energy Charge:

All kWh during the Summer On-Peak Hours .... ….$0.0475/kWh

All kWh during the Non-Summer On-Peak Hours $0.0475/kWh

All kWh during Off-Peak Hours $0.0375/kWh

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(4) Transformation Discount

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the Customer Charge plus the Demand Charge. Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Demands:

(A) Measured Demands:

The Customer's On-Peak Measured Demand for each monthly billing period shall be the Customer's maximum 30-minute integrated kW demand occurring during the On-Peak Hours of such billing period, as recorded by or determined from suitable measuring devices; provided, however, that during any billing period when the average power factor is less than eighty-five percent (85%), the On-Peak Measured Demand will be adjusted by multiplying such On-Peak Measured Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent for such period.

The Customer's Off-Peak Measured Demand for each monthly billing period shall be the Customer's maximum 30-minute integrated kW demand occurring during the Off-Peak Hours of such billing period, as recorded by or determined from suitable measuring devices; provided, however that during any billing period when the average power factor is less than eighty-five percent (85%), the Off-Peak Measured Demand will be adjusted by multiplying such Off-Peak Measured Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent for such period.

(B) Billing Demands:

The Customer's On-Peak Billing Demand for each monthly billing period shall be the greater of (i) the On-Peak Measured Demand for such period, or (ii) thirty percent (30%) of the greatest On-Peak Measured Demand computed for the preceding eleven months.

The Customer's Off-Peak Billing Demand for each monthly billing period shall be the amount, if any, by which the Customer's Off-Peak Measured Demand for such period exceeds the On-Peak Billing Demand for such period.

Section 6. Determination of On-Peak and Off-Peak Hours:

(A) Summer period On-Peak Hours shall mean the hours from 1:00 p.m. to 7:00 p.m., Monday through Friday, for the months of June, July, August, and September, excluding Memorial Day, Independence Day and Labor Day.

(B) Non-Summer period On-Peak Hours shall mean the hours from 6:00 a.m. to 10:00 a.m., Monday through Friday, for the months of, January, February, March, April, May, October, November, and December, excluding Christmas Day and New Year Day.

(C) The Off-Peak Hours are defined as all hours not specified above as On-Peak Hours.

Section 7. Payment:

All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges, on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 8. Period of Contract

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule GT-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE GENERAL SERVICE
SCHEDULE GL-18

Section 1. Availability:

This Schedule is available on or near the transmission facilities of the Authority to customers in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2: Applicability:

This Schedule is applicable to all customers having more than 300 kW demand in at least three months of any twelve (12) consecutive months and having a rolling twelve month average load factor of at least 70 percent.

Section 3. Character of Service:

Power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed. Energy and power taken under this schedule may not be resold or shared with others.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $26.00

(2) Demand Charge:

Billing Demand

All kW of Billing Demand $23.83/kW

(3) Energy Charges:

(a) Base Energy Charge:

Summer Season $0.0465/kWh
Non-Summer Season $0.0365/kWh

Summer Season - The Summer Season energy charge shall apply to all kWh used during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season - The Non-Summer season energy charge shall apply to all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Credit:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge" plus the "Demand Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Transformation Discount

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the above Firm Demand Charge shall be reduced by $0.60/kW.

When a Customer owns the step-down transformation equipment and all other facilities beyond the transformation which the Authority would normally own, except the Authority's metering equipment, necessary to take service from a distribution line of 12.47 kV or 34.5 kV from which the customer receives service and not from a transmission to distribution substation built primarily for the customer's use, the charge per kW of Billing Demand will be reduced by $0.50.

Section 6. Determination of Demands:

(A) Measured Demand:

The Measured Demand shall be the maximum 30-minute integrated kW demand recorded by suitable measuring devices during each billing period; provided, however, that during any billing period when the average power factor as determined by calculation from readings of a watt-hour and "q-hour" or var-hour meter (equipped with detents) is less than eighty-five percent (85%), the Measured Demand for billing purposes will be adjusted by multiplying such Demand by eighty-five percent (85%) and dividing the product by the actual average power factor in percent as calculated for the particular period.

(B) Billing Demand:

The monthly Billing Demand shall be the greater of (i) the Measured Demand for the current billing period, or (ii) thirty percent (30%) of the greatest Measured Demand computed for the preceding eleven months.

Section 7. Payment:

All bills are due and payable in good funds at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased by the larger of one hundred dollars ($100.00), or two percent (2%) of the amount then outstanding including late payment charges. on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 8. Metering

Power and energy shall be metered at the point of delivery by the Authority.

Section 9. Period of Contract:

The contract period will depend upon the facilities required to serve the Customer, but shall not be less than one (1) year.

Section 10. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule GL-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TEMPORARY SERVICE
SCHEDULE TP-18

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina. This Schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to service of a temporary nature for all service of the same available character supplied to the Customer's premises through a single delivery point. For service of a temporary nature and after the initial 12 months of service, the Authority will review each temporary customer and, at its option, may elect to place the service on one of the Authority's other applicable schedules. Service will be provided only after application for service and execution of an agreement with the Authority covering costs of installation and termination of service. Energy taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single or three-phase as available, at the nominal standard voltage of the Authority as available and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at other delivery points shall be separately metered and billed.

Section 4. Monthly Rates and Charges:

(A) Basic Monthly Charges:

(1) Customer Charge:

For each month, a charge of $23.00

(2) Energy Charge:

(a) Base Energy Charge:

Summer Season $0.1468/kWh

Non-Summer Season $0.1268/kWh

Summer Season – The Summer Season energy charge shall apply to all kWh use for bills rendered during the months of June, July, August and September. Energy use for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh use for bills rendered in months other than the Summer Season.

(b) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge for single-phase service shall be the "Customer Charge." Customers requesting three-phase service should apply to the Authority for information on any special minimum bill.

(C) Installation and Termination Costs:

The Customer will be required to pay costs of installation and termination of service as calculated by the Authority, the payment for which will be set forth in an agreement executed by the Authority and the Customer. For temporary construction service all such payments shall be in advance, and in no event shall be less than $35.00 per connection.

(D) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payment in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding including late charges on the next bill rendered and on subsequent bills rendered each month thereafter until paid. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

<u>Section 6. Period of Contract</u>:

The contract period will depend upon the facilities required to serve the Customer and shall be determined by the Authority.

<u>Section 7. Terms and Conditions</u>:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted __________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule TP-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TRANSITION ADJUSTMENT
SCHEDULE TA-18

Section 1. Availability:

This Schedule is available, on a voluntary basis, in the retail service area of the Authority in Berkeley, Georgetown, (and Horry Counties, South Carolina. This schedule is not available for breakdown, standby, or supplementary service and shall not be used in parallel with other sources of electric power.

Section 2. Applicability:

This Schedule is applicable to all non-residential users of energy and power as of December 1, 2013 receiving service pursuant to General Service Rate Schedule GA or Temporary Service Schedule TP, and who do not qualify for such service, for all service of the same available character supplied to the Customer's premises through a single delivery point. Energy and power taken under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, single or three-phase, 60 Hertz, as available, at available voltage and at a single delivery point. The electrical characteristics of all equipment served must be acceptable to the Authority and must meet the Authority's specifications. Separate supplies for the same Customer at different voltages or at different delivery points shall be separately metered and billed.

Section 4. Limitation of Service:

During the course of a review of customer billing records, it was determined that approximately 100 customers did not comply with the applicability requirements for Schedule GA-09 (General Service) or its successor schedules. Effective December 1, 2012, the Authority began systematically transitioning customers receiving service pursuant to GA-09, and who previously received or would have received power pursuant to GC-96, to the appropriate General Service Rate Schedule.

This transition adjustment rate schedule was also made available to ball park lighting customers who did not comply with the applicability requirements for Temporary Service Schedule TP-12 or its successor schedules. Effective February 1, 2014, the Authority began systematically transitioning ball park lighting customers receiving service pursuant to TP-12, or who received or would have received power pursuant to the Temporary Service and Ball Park Lighting Schedule TP-09 rate schedule, to the appropriate General Service Rate Schedule.

The appropriate General Service Rate Schedule will be Schedule GB-18 and its Successor Rate Schedules, or other then appropriate, applicable Rate Schedules. Representatives of the Authority will assist customers to select the appropriate and applicable rate schedule.

To the extent a customer selects to transition to General Service Rate Schedule GB-18 or its Successor Rate Schedules, the following transition adjustment will apply. However, should a customer during the transition period terminate service, no transition adjustment shall apply.

As a result of transitioning a customer to the proper rate schedule, customers selecting General Service Rate Schedule GB-18 will be billed commencing on the date upon which the customer receives service under the new rate schedule herein.

Section 5. Basic Monthly Charges:

For each month, at the amount set forth in the appropriate Schedule.

(A) Customer Charge:……………………………………………………………………….$26.00

(16) Summer Energy Charges:……………………………………………………….$0.0644/kWh
Non-Summer Energy Charges………………………………………………….$0.0544/kWh

All kWh at the amounts set forth in the appropriate Schedule.

(e) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(f) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(17) Demand Charge:………………………………………………………………….$15.46/kW

All kW at the amount set forth in the appropriate Schedule.

(18) Transition Adjustment:

The non-summer energy charge for Schedule TA-18 will be determined by multiplying the energy charge in Schedule GB-18 or its Successor Rate Schedules by the following percentages in the appropriate year:

Apr.1			Adjustment
2018	Year	7	As Stated
2019	Year	8	130.00%
2020	Year	9	115.00%
2021	Year	10	100.00%

The summer energy charge for Schedule TA-18 will be determined by computing the difference between the summer and non-summer energy charge in Schedule GB-18 or its Successor Rate Schedules. This amount shall be added to the currently applicable TA-18

non-summer energy charge during the months specified in Schedule GB-18 or its Successor Rate Schedules.

The demand charge for Schedule TA-18 will be determined by multiplying the demand charge in Schedule GB-18 or its Successor Rate Schedules by the following percentages in the appropriate year:

Apr. 1			Adjustment
2018	Year	7	As Stated
2019	Year	8	77.00%
2020	Year	9	88.50%
2021	Year	10	100.00%

The ratios and charges set forth in this Transition Adjustment are subject to change if and when the Authority revises its rates and charges. All other provisions and Sections of the selected, applicable General Service Rate Schedule shall apply.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule TA-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
TRAFFIC SIGNAL SERVICE
SCHEDULE TL-18

Section 1. Availability:

This Schedule is available to all cities, towns, communities, and the State Highway Department located in the service area of the Authority.

Section 2. Applicability:

This Schedule is applicable for the operation of traffic signals located in the Authority's service area where the Authority has an existing secondary distribution line. Energy taken under this Schedule may not be resold or shared with other operations.

Section 3. Character of Service:

Energy and power delivered hereunder shall be alternating current, 60 Hertz, single-phase at 120 volts nominal.

Section 4. Installation:

The Authority will make its connection to the Customer's service wire on the Authority's nearest pole carrying 120/240 volt secondary. The Customer must furnish, install and maintain all service wires, fixtures and other equipment required for operation of the traffic signal installation.

Section 5. Monthly Billing Rate:

(A) Basic Monthly Charges:

(1) Metered Service:

(k) Customer Charge:

For each month, a charge of $27.50

(l) Base Energy Charge:

All kWh $0.1018/kWh

(19) Unmetered Service:

Base Energy Charge:

For each lamp using 25 watts or less .... $1.66 per lamp

For each lamp using 26 to 70 watts .... $2.25 per lamp

For each lamp using more than 70 watts .... $3.02 per lamp

(20) Fuel Adjustment:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to \$0.03641/kWh and 0.125, respectively.

(21) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(22) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The minimum charge shall be the same as the monthly charges set forth herein above; provided, however, that if separate bills are required for each installation, the minimum bill shall be \$5.00 per installation.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payment in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Determination of Energy Usage for Unmetered Service:

For purposes of applying the aforementioned Fuel Adjustment Clause and Demand Sales Adjustment Clause, the monthly kWh usage for service provided hereunder shall be as follows:

For each lamp using 25 watts or less……………………………………………….5 kWh

For each lamp using 26 to 70 watts ....22 kWh

For each lamp using more than 70 watts..44 kWh

Section 7. Billing and Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents (\$0.50) or two percent (2%) of the amount then outstanding including late payment charges.

Section 8. Period of Contract:

The contract period shall be one (1) year or longer at the Authority's option.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule TL-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING
SCHEDULE MS-18

Section 1. Availability:

This Schedule is available to all cities, towns, communities, and the State Highway Department located in the service area of the Authority.

Section 2. Applicability:

This Schedule is applicable for municipal series and multiple circuit street, highway and bridge lighting within and immediately adjacent to city, town and community limits. Energy taken under this Schedule may not be resold or shared with other operations.

Section 3. Character of Service:

Energy delivered hereunder shall be alternating current, 60 Hertz, at a nominal standard voltage of the Authority, as available. Lamps may be connected in series or in multiple circuits, at the Authority's option.

Section 4. Installation:

The Authority will provide all labor and equipment necessary for installation including lamps and glassware. If the Authority is requested to provide a steel standard for the mounting of a light, the Customer will provide mixed concrete in the amount required for the standard. The Authority will provide the necessary forms and labor for the concrete work.

All equipment and other equipment installed by the Authority shall remain the property of the Authority.

Section 5. Monthly Rates and Charges:

The monthly charges hereunder shall consist of the following charges:

(A) Base Monthly Charges:

(1) Fixtures and Standards:

There shall be a monthly charge for each fixture and standard provided by the Authority, based on the type and characteristics thereof, determined in accordance with Exhibits A and B hereto, which such Exhibits A and B may be amended by the Authority from time to time to reflect the types of fixtures and standards the Authority will make available. In addition, the Authority may, at its sole option, provide on a work-order basis, fixtures and standards not provided for in Exhibits A and B if the Customer agrees to pay the Authority's cost of providing and installing such standards and fixtures.

(2) Energy Charges:

(a) Base Energy Charge:

All kWh ....$0.0662/kWh.

(b) Fuel Adjustment Charge:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(c) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(h) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Minimum Charge:

The monthly charge shall be the total of the charges specified hereinabove.

(C) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 6. Determination of Energy Usage

To determine the Customer's energy usage at service connection, the Authority, at its option, may either (i) meter such energy usage, or (ii) estimate the monthly energy usage of such service based on the characteristics and mode of operation of the lamps and other equipment served therefrom.

Section 7. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges.

Section 8. Period of Contract:

The contract period shall be one (1) year or longer at the Authority's option.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule MS-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE MS-18

Exhibit A
Schedule of Available Poles and Arms

	Available Pole and Arm Type	Monthly Charge
1	Wood standard, 30'	$ 4.62
2	Wood, 35'	$ 5.30
3	Wood. 40'	$ 6.25
4	Fiberglass, Round, Black, 18'	$ 5.71
5	Fiberglass, Round, Brown, 20'	$ 5.89
6	Fiberglass, Round, 30'	$ 13.32
7	Fiberglass, Round, 40'	$ 13.43
8	Aluminum Standard, 25'	$ 12.21
9	Aluminum, Round, 35'	$ 20.70
10	Fiberglass, Round, 30' Breakaway DOT	$ 18.95
11	Light Pole, $301-$400	$ 10.26
12	Light Pole, $401-$500	$ 11.83
13	Light Pole, $501-$600	$ 13.34
14	Light Pole, $601-$700	$ 14.91
15	Light Pole, $701-$900	$ 17.21
16	Light Pole, $901-$1100	$ 20.10
17	Light Pole, $1101-$1300	$ 22.30
18	Light Pole, $1301-$1500	$ 24.50
19	Light Pole, $1501-$1700	$ 26.70
20	Light Pole, $1701-$1900	$ 28.90
21	Light Pole, $1901-$2100	$ 31.10
22	Light Pole, $2101-$2300	$ 33.30
23	Light Pole, $2301-$2500	$ 35.50
24	Light Pole Arm, $201-$400	$ 6.28
25	Light Pole Arm, $401-$600	$ 9.78
26	Light Pole Arm, $601-$800	$ 12.60
27	Light Pole Arm, $801-$1000	$ 15.40

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL STREET LIGHTING SERVICE
SCHEDULE MS-18

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
1	100 Watt, HPS, Private	41	$ 5.42
2	150 Watt, HPS, Private	61	$ 6.79
3	150 Watt, HPS, Traditional	61	$ 8.41
4	150 Watt, HPS, Roadway	61	$ 7.78
5	150 Watt, HPS, Modern (Shoebox)	61	$ 11.72
6	250 Watt, HPS, Roadway	103	$ 10.78
7	250 Watt, HPS, Shoebox	103	$ 14.94
8	400 Watt, HPS, Flood Light	164	$ 15.87
9	400 Watt, HPS, Roadway	164	$ 15.12
10	400 Watt, HPS, Shoebox	164	$ 19.51
11	400 Watt, MH, Flood Light	164	$ 16.76
12	400 Watt, MH, Galleria	164	$ 18.57
13	1000 Watt, MH, Flood Light	410	$ 34.04
14	1000 Watt, MH, Galleria	410	$ 36.11
15	$301-$400, 70 Watt, MH	29	$ 12.22
16	$301-$400, 175 Watt, MH	73	$ 15.13
17	$301-$400, 150 Watt, HPS	61	$ 14.55
18	$401-$500, 70 Watt MH	29	$ 13.62
19	$401-$500, 175 Watt MH	73	$ 16.53
20	$401-$500, 150 Watt HPS	61	$ 16.24
21	$401-$500, 250 Watt MH	103	$ 18.52
22	$401-$500, 250 Watt HPS	103	$ 19.02
23	$401-$500, 400 Watt MH	164	$ 22.56
24	$401-$500, 400 Watt HPS	164	$ 23.06
25	$401-$500, 1000 Watt MH	410	$ 38.85
26	$401-$500, 1000 Watt HPS	410	$ 39.35
27	$501-$600, 70 Watt MH	29	$ 15.02
28	$501-$600, 175 Watt MH	73	$ 17.93
29	$501-$600, 150 Watt HPS	61	$ 17.74
30	$501-$600, 250 Watt MH	103	$ 19.92
31	$501-$600, 250 Watt HPS	103	$ 20.52
32	$501-$600, 400 Watt MH	164	$ 23.96
33	$501-$600, 400 Watt HPS	164	$ 24.56
34	$501-$600, 1000 Watt MH	410	$ 40.25
35	$501-$600, 1000 Watt HPS	410	$ 40.85
36	$601-$700, 70 Watt MH	29	$ 16.42
37	$601-$700, 175 Watt MH	73	$ 19.33
38	$601-$700, 150 Watt HPS	61	$ 19.14
39	$601-$700, 250 Watt MH	103	$ 21.32

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
40	$601-$700, 250 Watt HPS	103	$ 21.92
41	$601-$700, 400 Watt MH	164	$ 25.36
42	$601-$700, 400 Watt HPS	164	$ 25.96
43	$601-$700, 1000 Watt MH	410	$ 41.65
44	$601-$700, 1000 Watt HPS	410	$ 42.25
45	$701-$800 175 Watt, MH	73	$ 20.73
46	$701-$800 150 Watt, HPS	61	$ 20.54
47	$701-$800 250 Watt, MH	103	$ 22.72
48	$701-$800 250 Watt, HPS	103	$ 23.32
49	$701-$800 400 Watt, MH	164	$ 26.76
50	$701-$800 400 Watt, HPS	164	$ 27.36
51	$701-$800 1000 Watt, MH	410	$ 43.05
52	$701-$800 1000 Watt, HPS	410	$ 43.65
53	$801-$900 175 Watt, MH	73	$ 22.13
54	$801-$900 150 Watt, HPS	61	$ 21.94
55	$801-$900 250 Watt, MH	103	$ 24.12
56	$801-$900 250 Watt, HPS	103	$ 24.72
57	$801-$900 400 Watt, MH	164	$ 28.16
58	$801-$900 400 Watt, HPS	164	$ 28.76
59	$801-$900 1000 Watt, MH	410	$ 44.45
60	$801-$900 1000 Watt, HPS	410	$ 45.05
61	$901-$1000 175 Watt, MH	73	$ 23.53
62	$901-$1000 150 Watt, HPS	61	$ 23.34
63	$901-$1000 250 Watt, MH	103	$ 25.52
64	$901-$1000 250 Watt, HPS	103	$ 26.12
65	$901-$1000 400 Watt, MH	164	$ 29.56
66	$901-$1000 400 Watt, HPS	164	$ 30.16
67	$901-$1000 1000 Watt, MH	410	$ 45.85
68	$901-$1000 1000 Watt, HPS	410	$ 46.45
69	Vandal Shield (1)	-	$ 1.90
Experimental Fixtures (Energy Not Included in Monthly Rental Charge)			
70	$101-$300 Range, LED (3)	Varies by Fixture	*$6.21*
71	$301-$500 Range, LED (3)	Varies by Fixture	*$8.42*
72	$501-$700 Range, LED (3)	Varies by Fixture	*$10.64*
73	$701-$900 Range, LED (3)	Varies by Fixture	*$12.85*
74	$901-$1100 Range, LED (3)	Varies by Fixture	*$15.06*
75	$1101-$1300 Range, LED (3)	Varies by Fixture	*$17.27*
76	$1301-$1500 Range, LED (3)	Varies by Fixture	*$19.48*

Note 1: Vandal Shields may be required for fixtures receiving damage more than once during any consecutive three year period.

Note 2: All monthly rental charges include energy charges unless otherwise specified.

Note 3: Experimental fixtures do not include energy charges. Energy charges will vary based on specific fixture energy requirements and will be in addition to the stated rental charges.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-18

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable for outdoor yard and area lighting to retail customers where the Authority installs and furnishes the lighting equipment including lamps, fixtures, and the necessary lighting circuits and fittings. The monthly facilities and energy charges set forth in Section 4 are applicable only to lighting fixtures located so as to be furnished energy by existing facilities, poles and transformers on existing poles, or through the addition of not more than one (1) wood pole for attachment of each lighting fixture. Where extension of primary lines or special facilities or more than one (1) new pole per lighting fixture is required, the cost of constructing such additional facilities shall be repaid by the customer requesting service. Energy purchased under this Schedule may not be resold or shared with others.

Section 3. Character of Service:

The Authority shall provide the outdoor yard and area lighting service hereunder including providing, installing, and maintaining the necessary facilities such as requisite poles and light fixtures on a contractual basis. Upon request for service, the Authority will require the execution of an agreement between the customer and the Authority (the "Outdoor Rental Lighting Agreement"). Energy delivered hereunder shall be alternating current 60 Hertz at the nominal standard voltage of the Authority, as available.

Section 4. Monthly Rates and Charges:

The monthly charges hereunder shall include the following charges:

(A) Basic Monthly Charges:

(1) Pole and Fixture Rental Fees:

There shall be a monthly charge for each pole and fixture furnished by the Authority, based on the type and characteristics thereof, determined in accordance with Exhibits A and B hereto. Such Exhibits A and B may be amended by the Authority from time to time to reflect the standard types of poles and fixtures the Authority will make available.

(2) Energy Charges:

(a) Base Energy Charge:

For each fixture, there shall be a base energy charge of $0.0662/kWh for all kWh of energy use.

(b) Fuel Adjustment Charge:

The Authority's Fuel Adjustment Clause FAC-18 is applicable to all energy sales hereunder, with "F/S" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.125, respectively.

(m) Demand Sales Adjustment:

The Authority's Demand Sales Adjustment Clause DSC-18 is applicable to all energy sales hereunder.

(i) Economic Development Sales Adjustment:

The Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any, is applicable to all energy sales hereunder.

(B) Additional Facilities Charge:

The Basic Monthly Charges herein apply only to fixtures located so as to be furnished energy by existing facilities, poles and transformers on existing poles, and/or through the addition of not more than one pole for the attachment of each lighting fixture. Additional facilities, including the extension of primary lines, or special facilities, or more than one (1) new pole per lighting fixture, will be furnished by the Authority where the customer agrees to pay the cost of constructing such additional facilities.

(C) Minimum Charge:

The minimum charge shall be the same as the monthly charges set forth in Sections 4.A. and 4.B. hereinabove.

(D) Taxes:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the customer has furnished the Authority evidence of specific exemption secured by the customer from the South Carolina Tax Commission or its successor.

Section 5. Determination of Energy Usage:

The Authority, at its option, may meter the monthly kWh energy usage of light fixtures provided hereunder. Otherwise, each unmetered fixture shall be deemed to use the estimated average monthly kWh energy set forth in the currently effective Exhibit B hereto.

Section 6. Payment:

(A) Bills for service hereunder shall become part of and shall be added to the customer's monthly account for metered electric service.

(B) Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. When the outdoor light is the only account with the Authority and payment of the bill is not received by said due date, the amount of the bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($0.50) or two percent (2%) of (i) the amount calculated under Section 4 of this Schedule or (ii) the total amount then outstanding including late payment charges. If the outdoor light is billed in conjunction with another account and payment of the bills is not received by said due date, then the total bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter by the larger of fifty cents ($0.50) or two percent (2%) of (i) the total amount calculated under this Schedule or (ii) the total bill then outstanding including late payment charges.

Section 7. Period of Contract:

The Outdoor Rental Lighting Agreement shall become effective on the date the lighting fixtures are first installed and operated and shall remain in effect for a period of three (3) years and thereafter until terminated by either party giving to the other thirty (30) days notice. In the event that the customer transfers, terminates or, for any reason, discontinues outdoor yard and area lighting service and/or electric service to the property on which the rental lighting is installed, the following charges shall become due and payable and may be paid in whole or in part by any deposit for electric service that the customer may have made:

> The greater of (i) the sum of the monthly charges for all remaining months of the effective terms of the Outdoor Rental Lighting Agreement, or (ii) fifty dollars ($50.00) for each fixture mounted on existing facilities, or (iii) one hundred fifty dollars ($150.00) for each fixture and pole that is caused to be removed due to termination of the Outdoor Rental Lighting Agreement.

In the event the customer wishes to terminate the private outdoor lighting service due to the sale, lease, or rental to others of the property on which lights are installed and the new party wishes to continue the rental agreement, the Authority shall release the customer from the termination charges provided for herein at such time that the new customer makes application for electric service and signs and Outdoor Rental Lighting Agreement for the remaining months of the original agreement.

Section 8. Limitations of Service:

(A) The Authority assumes the responsibility for ordinary maintenance of poles, equipment and lamps with all maintenance work to be performed during normal working hours at the discretion of the Authority.

(B) The Authority shall use reasonable diligence to provide a constant service to the lighting fixtures, but if such service or equipment shall fail or be interrupted, or become defective through acts of nature, or public enemies or by accident, strikes, labor troubles or by actions of the elements, or for any cause beyond its reasonable control, the Authority shall not be liable therefore.

(C) The Customer shall assume responsibility of providing reasonable protection to the lighting installation from accidental collision by motor vehicle and other similar equipment and shall further assume responsibility of providing the installation protection against vandalism.

(D) The Authority reserves the right to terminate private outdoor lighting service immediately upon the threat of damage or continued damage to the installed equipment.

Section 9. Terms and Conditions:

This Schedule is subject to the Authority's Terms and Conditions of Retail Electric Service currently in effect and the "Outdoor Rental Lighting Agreement" executed between the customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule OL-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-18

Exhibit A
Schedule of Available Poles and Arms

	Available Pole and Arm Type	Monthly Charge
1	Wood standard, 30'	$ 4.62
2	Wood, 35'	$ 5.30
3	Wood. 40'	$ 6.25
4	Fiberglass, Round, Black, 18'	$ 5.71
5	Fiberglass, Round, Brown, 20'	$ 5.89
6	Fiberglass, Round, 30'	$ 13.32
7	Fiberglass, Round, 40'	$ 13.43
8	Aluminum Standard, 25'	$ 12.21
9	Aluminum, Round, 35'	$ 20.70
10	Fiberglass, Round, 30' Breakaway DOT	$ 18.95
11	Light Pole, $301-$400	$ 10.26
12	Light Pole, $401-$500	$ 11.83
13	Light Pole, $501-$600	$ 13.34
14	Light Pole, $601-$700	$ 14.91
15	Light Pole, $701-$900	$ 17.21
16	Light Pole, $901-$1100	$ 20.10
17	Light Pole, $1101-$1300	$ 22.30
18	Light Pole, $1301-$1500	$ 24.50
19	Light Pole, $1501-$1700	$ 26.70
20	Light Pole, $1701-$1900	$ 28.90
21	Light Pole, $1901-$2100	$ 31.10
22	Light Pole, $2101-$2300	$ 33.30
23	Light Pole, $2301-$2500	$ 35.50
24	Light Pole Arm, $201-$400	$ 6.28
25	Light Pole Arm, $401-$600	$ 9.78
26	Light Pole Arm, $601-$800	$ 12.60
27	Light Pole Arm, $801-$1000	$ 15.40

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
PRIVATE OUTDOOR LIGHTING SERVICE
SCHEDULE OL-18

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
1	100 Watt, HPS, Private	41	$ 5.42
2	150 Watt, HPS, Private	61	$ 6.79
3	150 Watt, HPS, Traditional	61	$ 8.41
4	150 Watt, HPS, Roadway	61	$ 7.78
5	150 Watt, HPS, Modern (Shoebox)	61	$ 11.72
6	250 Watt, HPS, Roadway	103	$ 10.78
7	250 Watt, HPS, Shoebox	103	$ 14.94
8	400 Watt, HPS, Flood Light	164	$ 15.87
9	400 Watt, HPS, Roadway	164	$ 15.12
10	400 Watt, HPS, Shoebox	164	$ 19.51
11	400 Watt, MH, Flood Light	164	$ 16.76
12	400 Watt, MH, Galleria	164	$ 18.57
13	1000 Watt, MH, Flood Light	410	$ 34.04
14	1000 Watt, MH, Galleria	410	$ 36.11
15	$301-$400, 70 Watt, MH	29	$ 12.22
16	$301-$400, 175 Watt, MH	73	$ 15.13
17	$301-$400, 150 Watt, HPS	61	$ 14.55
18	$401-$500, 70 Watt MH	29	$ 13.62
19	$401-$500, 175 Watt MH	73	$ 16.53
20	$401-$500, 150 Watt HPS	61	$ 16.24
21	$401-$500, 250 Watt MH	103	$ 18.52
22	$401-$500, 250 Watt HPS	103	$ 19.02
23	$401-$500, 400 Watt MH	164	$ 22.56
24	$401-$500, 400 Watt HPS	164	$ 23.06
25	$401-$500, 1000 Watt MH	410	$ 38.85
26	$401-$500, 1000 Watt HPS	410	$ 39.35
27	$501-$600, 70 Watt MH	29	$ 15.02
28	$501-$600, 175 Watt MH	73	$ 17.93
29	$501-$600, 150 Watt HPS	61	$ 17.74
30	$501-$600, 250 Watt MH	103	$ 19.92
31	$501-$600, 250 Watt HPS	103	$ 20.52
32	$501-$600, 400 Watt MH	164	$ 23.96
33	$501-$600, 400 Watt HPS	164	$ 24.56
34	$501-$600, 1000 Watt MH	410	$ 40.25
35	$501-$600, 1000 Watt HPS	410	$ 40.85
36	$601-$700, 70 Watt MH	29	$ 16.42
37	$601-$700, 175 Watt MH	73	$ 19.33
38	$601-$700, 150 Watt HPS	61	$ 19.14
39	$601-$700, 250 Watt MH	103	$ 21.32

Exhibit B
Schedule of Available Light Fixtures and Shield

	Available Fixture Type	Average Monthly kWh Usage	Monthly Rental Charge
40	$601-$700, 250 Watt HPS	103	$ 21.92
41	$601-$700, 400 Watt MH	164	$ 25.36
42	$601-$700, 400 Watt HPS	164	$ 25.96
43	$601-$700, 1000 Watt MH	410	$ 41.65
44	$601-$700, 1000 Watt HPS	410	$ 42.25
45	$701-$800 175 Watt, MH	73	$ 20.73
46	$701-$800 150 Watt, HPS	61	$ 20.54
47	$701-$800 250 Watt, MH	103	$ 22.72
48	$701-$800 250 Watt, HPS	103	$ 23.32
49	$701-$800 400 Watt, MH	164	$ 26.76
50	$701-$800 400 Watt, HPS	164	$ 27.36
51	$701-$800 1000 Watt, MH	410	$ 43.05
52	$701-$800 1000 Watt, HPS	410	$ 43.65
53	$801-$900 175 Watt, MH	73	$ 22.13
54	$801-$900 150 Watt, HPS	61	$ 21.94
55	$801-$900 250 Watt, MH	103	$ 24.12
56	$801-$900 250 Watt, HPS	103	$ 24.72
57	$801-$900 400 Watt, MH	164	$ 28.16
58	$801-$900 400 Watt, HPS	164	$ 28.76
59	$801-$900 1000 Watt, MH	410	$ 44.45
60	$801-$900 1000 Watt, HPS	410	$ 45.05
61	$901-$1000 175 Watt, MH	73	$ 23.53
62	$901-$1000 150 Watt, HPS	61	$ 23.34
63	$901-$1000 250 Watt, MH	103	$ 25.52
64	$901-$1000 250 Watt, HPS	103	$ 26.12
65	$901-$1000 400 Watt, MH	164	$ 29.56
66	$901-$1000 400 Watt, HPS	164	$ 30.16
67	$901-$1000 1000 Watt, MH	410	$ 45.85
68	$901-$1000 1000 Watt, HPS	410	$ 46.45
69	Vandal Shield (1)	-	$ 1.90
	Experimental Fixtures (Energy Not Included in Monthly Rental Charge)		
70	$101-$300 Range, LED (3)	Varies by Fixture	*$6.21*
71	$301-$500 Range, LED (3)	Varies by Fixture	*$8.42*
72	$501-$700 Range, LED (3)	Varies by Fixture	*$10.64*
73	$701-$900 Range, LED (3)	Varies by Fixture	*$12.85*
74	$901-$1100 Range, LED (3)	Varies by Fixture	*$15.06*
75	$1101-$1300 Range, LED (3)	Varies by Fixture	*$17.27*
76	$1301-$1500 Range, LED (3)	Varies by Fixture	*$19.48*

Note 1: Vandal Shields may be required for fixtures receiving damage more than once during any consecutive three year period.

Note 2: All monthly rental charges include energy charges unless otherwise specified.

Note 3: Experimental fixtures do not include energy charges. Energy charges will vary based on specific fixture energy requirements and will be in addition to the stated rental charges.

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
MUNICIPAL LIGHT AND POWER
SCHEDULE ML-18

Section 1. Availability:

(G) Service hereunder is available at Delivery Points on or near the transmission facilities of the Authority to municipal, sales-for-resale customers having a contract demand of 1,000 kilowatts or more.

(H) This Rate Schedule is not available for breakdown, standby, supplementary, or auxiliary service, and service hereunder shall not be used in parallel with other sources of electric power.

(I) Prior to the provision of service hereunder at one or more Delivery Points, the Customer shall have entered into a Service Agreement, mutually agreeable to the Customer and the Authority, that shall set forth general terms and conditions of service hereunder.

Section 2. Character of Service:

(C) Electric power and energy delivered hereunder shall be unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, at one of the Authority's standard nominal voltages of 480 volts or higher. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed. Only one transformation will be provided hereunder from the available transmission voltage.

Section 3. Monthly Rates and Charges:

(A) Charges for Power Service:

(1) Monthly Customer Charge:

A monthly charge for each Delivery Point of $1,500.00

(2) Monthly Demand Charge:

(a) Base Demand Charge:

For the first 1,000kW or less of Billing Demand........................ $18,180.00

All Additional kW of Billing Demand $18.18

(b) Transformation Discount:

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the foregoing Base Monthly Demand Charge shall be reduced by $0.60/kW.

(c) Excess Demand Charge:

For each kW of the Customer's Measured Demand that is classified as Excess Demand, a charge, in addition to the Base Demand Charge, of $12.00/kW.

(n) Demand Sales Adjustment:

For each kW of Billing Demand, a credit or change, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment DSC-18, or its currently applicable successor clause, if any.

(o) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any.

(3) Energy Charge:

(a) Base Energy Charge:

All kWh $0.0416/kWh

(f) Fuel Adjustment Clause:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-18, or its currently applicable successor clause, if any, with "Fb/Sb" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(3) Excess Reactive Demand Charge:

Each kVAr of Excess Reactive Demand $0.82/kVAr

(E) Monthly Facilities Charges:

In the event service to the Customer requires the Authority to provide facilities in addition to, or different from, facilities normally provided by the Authority, and the Authority provides such facilities, the Customer also shall pay the Authority a Monthly Facilities Charge, in addition to all other charges hereunder. Such Monthly Facilities Charge shall be equal to 1.4% of the original installed cost of such facilities.

(F) Minimum Monthly Bill:

The minimum monthly bill shall consist of the sum of the Monthly Customer Charge, the Monthly Demand Charge, and the Monthly Facilities Charge, if any.

(D) Taxes and Other Assessments:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the foregoing monthly rates and charges. The total monthly billing amount hereunder also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Determination of Demands:

(C) Billing Demand:

(1) The Billing Demand for each Billing Month shall be the greater of (i) the Customer's Measured Demand for such Billing Month or (ii) eighty percent (80%) of the Contract Demand for such Billing Month.

(2) In the event that, during any Billing Month, the provision of service by the Authority hereunder is interrupted for a period of four (4) or more consecutive hours as a result of an occurrence of one of the circumstances set forth in Section 6(A) hereof, the Billing Demand for such Billing Month will be reduced by the proportion which the number of hours of such interruption bears to the total number of hours in the Billing Month.

(B) Measured Demand:

The Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the customer during such Billing Month; provided, however, that if the Customer's load is unbalanced between phases by more than ten percent (10%), the Authority, at its sole option, may (i) require the Customer, at the Customer's expense, to make the changes necessary to correct such condition, and/or (ii) assume that the load on each phase is equal to the greatest load on any phase.

(C) Contract Demand:

(1) Except as otherwise provided herein, the Contract Demand applicable to each Delivery Point during each Billing Month shall be the maximum amount of power, in kilowatts, that the Customer shall have requested and the Authority shall have agreed to supply during such Billing Month, as evidenced in the Service Agreement between the Customer and the Authority. During the first twelve (12) months of service to a new Delivery Point, the Authority, at its sole option, may agree to adjust the Customer's Contract Demand on a month-to-month basis and/or to forego the application of Section 4 (D) hereinbelow, in order to allow the Customer and the Authority an adequate build-up or phase-in of operations; provided, however, that the Authority reserves the right to condition such agreement on such additional terms and conditions as the Authority deems appropriate for the circumstances.

(2) Except as otherwise provided herein or in the Service Agreement between the Customer and the Authority, the Customer may reduce its Contract demand for a Delivery Point, or any twelve month period and subsequent twelve month periods, to not less than 1,000 kW by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first Period to which the notice applies, provided, however, that (i) no such reduction shall become effective before the fifth anniversary of service to the Delivery point, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Contract Demand for such year.

(f) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Contract Demand(s) for such years.

Notices of such reductions in the Customer's Contract Demand shall be irrevocable once given.

(3) The Customer's Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rate Schedule, or (ii) by mutual agreement between the Authority and the Customer. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request by the Customer. In such an event, the Authority may require additional, special terms and conditions applicable to service to the Customer.

(D) Excess Demand:

(1) The Customer's Excess Demand for each Billing Month shall be that portion of the Customer's Measured Demand for such Billing Month that exceeds 110% of the Customer's then current Contract Demand hereunder.

(2) Notwithstanding the foregoing or any other provision of this Rate Schedule to the contrary, in the event that (i) the Customer's rate or use of electricity at a Delivery Point exceeds the Customer's then current Contract Demand hereunder, and (ii) the Customer fails to comply promptly with a request by the Authority to reduce such rate of use so as not to exceed such aggregate Contract Demand, the Customer's Contract Demand(s) for such Delivery Point for the current and subsequent Billing Months, shall at the Authority's sole option, be increased, from what it otherwise would have been, by the amount of such excess. In addition, in such event, the Customer shall be liable for any damage to the Authority's facilities caused by such excess.

(3) Notwithstanding the foregoing or any other provision of this Rate Schedule, the Authority shall be under no obligation whatsoever to supply demands in excess of the Customer's Contract Demand, and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed the Customer's Contract Demand.

(E) Excess Reactive Demand:

The Customer's Excess Reactive Demand for each Billing Month shall be the amount, if any, by which the Customer's maximum 30-minute integrated reactive demand, in kilovars (kVAr) during such Billing Month exceeds 48.5% of the Customer's Measured Demand, in kilowatts (kW), for such Billing Month.

Section 5. Billing:

All bills are due and payable at the offices of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased by the greater of (i) one hundred dollars ($100.00), or (ii) two percent (2%) of the amount then outstanding including late payment charges. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of the service shall not relieve the Customer of any liability for the Agreed Minimum Bill(s) for the period(s) of time service is so discontinued.

Section 6. Interruption of Service:

(A) The Authority will make reasonable provisions to ensure satisfactory and continuous service but does not guarantee a continuous supply of electrical energy and shall not be liable for damage occasioned by interruptions of service or failure to commence delivery caused by an act of God, or the public enemy, or for any cause reasonably beyond the Authority's control, including, but not limited to, the failure or breakdown of generating or transmitting facilities, floods, fire, strikes or action or order of any agency having jurisdiction over the premises, or for interruptions that the Authority deems necessary for the inspection of, repair to, or changes to the Authority's facilities.

(B) Nothing herein shall be construed as restricting in any way the Authority's right to interrupt service to the Customer as the Authority may deem necessary or appropriate to facilitate inspection of, repair to, or changes to the Authority's facilities consistent with prudent utility practice; provided, however, that the Authority shall use its reasonable best efforts, when practicable, to provide the Customer with advance notice of such interruptions and to coordinate with the Customer the times of such interruptions. In any event, failure of the Authority and the Customer to agree upon the time of such an interruption shall not restrict the Authority from proceeding therewith as the Authority deems necessary.

(C) The Customer shall provide written notification to the authority immediately of any defects, trouble or accident which may in any way affect the delivery of power by the Authority to the Customer.

(D) Notwithstanding any provisions of this Rate Schedule to the contrary, the Customer shall not be liable for any charges hereunder for any period during which he is unable to accept electric service due to strikes, fire, floods, or act of God or the public enemy.

(E) Both the Customer and the Authority shall use all due diligence in removing any causes which prevent the delivery or use of electrical power and energy hereunder.

(F) Any claims against the Authority resulting from an interruption of service shall be governed by the terms, conditions and limitations of the South Carolina Tort Claims Act, and any recovery in such claim shall not include indirect or consequential damages.

Section 7. Indemnity:

All electrical power and energy provided for hereunder shall be the property of the Customer upon passing the Delivery Point(s) and the Customer shall have sole responsibility for the use, misuse or presence of said power and energy on the Customer's side of the Delivery Point(s). The Customer will indemnify and hold the Authority harmless from al claims, loss or expense arising from, or in any way connected with, the presence, use of misuse of electrical power and energy on the Customer's side of the Delivery Point(s).

Section 8. Additional Terms and Conditions:

Service under this Rate Schedule is subject to the then currently effective Service Agreement between the Customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted _________, 2015
Effective for service rendered on or after April 1, 2018

Supersedes:
Schedule ML-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
SCHEDULE L-18

Section 1. Availability:

(A) Service hereunder is available at Delivery Points on or near the transmission facilities of the Authority at which the Customer has a potential demand for electric service of at least 1,000 kW; provided, however, that service hereunder shall not be available for service to large, highly fluctuating or otherwise unusual loads without the agreement of the Authority.

(B) Subject to the terms of this Rate Schedule and the General Terms and Conditions of Large Power Electric Service (hereinafter, "General Terms and Conditions") attached hereto as Attachment A and made a part hereof, service hereunder is available, at individual Delivery Points each satisfying the requirements of the foregoing paragraph, to (i) industrial, commercial, and governmental Customers of the Authority, and (ii) municipal and cooperative wholesale Customers of the Authority may offer this service to an industrial, commercial, or governmental customer of such wholesale customer.

(C) Except as may be otherwise provided in the Standby Service Rider L-18-SB, this Rate Schedule is not available for breakdown, standby, supplementary, or auxiliary service, and service hereunder shall not be used in parallel with other sources of electric power. Except with respect to service to municipal and cooperative Customers of the Authority, as provided in the foregoing paragraph, service hereunder shall not be sold for resale or exchange or shared with others.

(D) Prior to the provision of service hereunder at one or more Delivery Points, the Customer shall be required to enter into an Agreement for Large Power Electric Service (hereinafter, "Service Agreement") of the form prescribed in the General Terms and Conditions which may be modified by the Authority from time to time.

Section 2. Character of Service:

(A) Electric power and energy delivered hereunder shall be unregulated, three-phase alternating current, at a frequency of approximately 60 Hertz, at one of the Authority's standard nominal voltages of 480 volts or higher. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed. Only one transformation will be provided hereunder from the available transmission voltage.

(B) "Firm Power," as used herein, shall refer to electric power and energy purchased by the Customer hereunder, other than electric power and energy purchased by the Customer pursuant to any other applicable rider or riders hereto.

Section 3. Monthly Rates and Charges:

(A) Monthly Customer Charge:

A monthly charge for each Delivery Point of $3,400.00

(B) Charges for Standard Firm Power Service:

The monthly charges for Firm Power hereunder shall include the following charges:

(1) Monthly Demand Charge:

(a) Base Demand Charge:

For the first 300 kW or less of Firm Billing Demand $7,664.00

All Additional kW of Firm Billing Demand @ $19.65

(c) Transformation Discount:

Whenever the Customer takes delivery at available transmission voltage (69 kV or greater) and provides the necessary transformation from the available transmission voltage, the foregoing Base Monthly Demand Charge shall be reduced by $0.60/kW.

(d) Excess Demand Charge:

(v) For each kW of the Customer's Measured Demand that is classified as Excess On-Peak Demand, a charge, in addition to the Base Demand Charge, of $12.00/kW.

(vi) For each kW of the Customer's Measured Demand that is classified as Excess Off-Peak Demand, a charge equal to the Base Demand Charge.

(e) Excess Reactive Demand Charge:

Each kVAr of Excess Reactive Demand @ $0.82/kVAr

(f) Demand Sales Adjustment:

For each kW of Firm Billing Demand, a credit or charge, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment Clause DSC-18, or its currently applicable successor clause, if any.

(g) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any.

(2) Energy Charge:

(c) Base Energy Charge:

On-Peak kWh @ $0.0575/kWh

Off-Peak kWh @ $0.0375/kWh

(h) ....
For all energy taken during the month and classified under the Off-Peak Demand provision, an Off-Peak Energy Premium of $0.02175/kWh shall apply. Such charge shall be in addition to the Off-Peak Base Energy Charges above.

(i) Fuel Adjustment Charge:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-18, or its currently applicable successor clause, if any, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.09, respectively.

(C) Charges Under Applicable Riders:

The monthly charges hereunder shall include the charges for services provided the Customer under any and all applicable riders hereto.

(D) Monthly Facilities Charges:

In the event service to the Customer requires the Authority to provide facilities in addition to, or different from, facilities normally provided by the Authority, and the Authority provides such facilities, the Customer also shall pay the Authority a Monthly Facilities Charge, in addition to all other charges hereunder. Such Monthly Facilities Charge shall be equal to 1.4% of the original installed cost of such facilities.

(E) Minimum Monthly Bill:

The minimum monthly bill shall consist of the sum of (i) the Monthly Customer Charge, (ii) the Monthly Facilities Charge, if any, (iii) the Monthly Demand Charge for Firm Power Service, and (iv) the minimum monthly charges, if any, determined pursuant to any applicable rider or riders under which the Customer also receives service from the Authority.

(F) Taxes and Other Assessments:

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the foregoing monthly rates and charges. The total monthly billing amount hereunder also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Determination of Demands:

(A) Firm Billing Demand:

(1) The Firm Billing Demand for each Billing Month shall be greater of (i) On-Peak Measured Demand, or (ii) eighty percent (80%) of the Firm Contract Demand, but no greater than one

hundred (100%) of Firm Contract Demand for such Billing Month. If the Customer receives Firm Power only, then the Customer's Firm Billing Demand shall not be less than 1,000 kW.

(2) In the event that, during any Billing Month, the provision of service by the Authority hereunder is interrupted for a period of four (4) or more consecutive hours as a result of an occurrence of one of the circumstances set forth in Section 9(A) of the General Terms and Conditions, the Firm Billing Demand for such Billing Month will be reduced by the proportion which the number of hours of such interruption bears to the total number of hours in the Billing Month.

(3) The Customer's Off-Peak Demand Provision shall refer to the amount, if any, by which (a) the lesser of (i) Off-Peak Measured Demand during that Billing Month or (ii) the Customer's then current Off-Peak Maximum demand exceeds (b) the sum of the Firm Contract Demand hereunder plus the Customer's Contract Demands (if any) under any and all riders hereto and other rate schedules of the Authority, plus the Customer's Excess Firm On-Peak Demand (if any) during that billing month. The Customer's Off-Peak Maximum Demand shall be established at the request of the Customer and modified by the Authority from time to time in recognition of the limitations of the delivery facilities serving the Customer and other limiting considerations on the Authority's system however, in no event shall requested demand exceed 20 percent (20%) of the sum of the Customer's Firm and Interruptible Contract Demand(s). Unless and until the authority shall have agreed in writing to a specific Off-Peak Maximum Demand, it shall be deemed to be equal to the sum of the Firm Contract Demand hereunder plus the Customer's Contract Demand(s) (if any) under any and all riders hereto and other rate schedules of the Authority, exclusive of Nominated of curtailed capacity as provided under L-18-DRB. All energy served under the Off-Peak Demand Provision shall incur charges as described in Section 3(B)(2)(b).

(4) Firm Billing Demand, and the Off-Peak Demand Provision, as described and calculated herein, shall be exclusive of Nominated or curtailed capacity as provided under L-18-DRB, including provisions for Customer's Contract Demand(s) in Section 4 (A) (1) and Section 4 (A) (3) above.

(B) Measured Demand:

(1) Subject to the applicable provisions, if any, of any rider or riders hereto pursuant to which the Customer also receives service, the Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the customer during such Billing Month.

(2) The On-Peak Measured Demand for each Billing Month shall be the maximum 30-minute integrated kW demand of the Customer that shall have occurred during the Billing Month during On-Peak Demand Hours. As used herein, On-Peak Demand Hours shall refer to the same as stated in Section 5(A).

(3) The Off-Peak Measured Demand shall be the maximum 30-minute integrated kW demand of the Customer that shall have occurred in the Billing Month at a time other than during On-Peak Demand Hours.

(4) In determining each of the Customer's Measured Demand, On-Peak Measured Demand, and Off-Peak Measured Demand, whenever the Customer's load is unbalanced between phases by more than ten percent (10%), the load on each phase shall be deemed to be equal to the greatest load on any phase. Furthermore, whenever the Customer's load frequently is found to be unbalanced between phases by more than ten percent (10%), the Authority, at its sole option, may require the Customer, at the Customer's expense, to make the changes necessary to correct such condition.

(C) Firm Contract Demand:

(1) Except as otherwise provided herein, the Firm Contract Demand applicable to each Delivery Point during each Billing Month shall be the maximum amount of Firm Power, in kilowatts, that the Customer shall have requested and the Authority shall have agreed to supply during such Billing Month, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and made a part of, the Service Agreement between the Customer and the Authority. During the first twelve (12) months of service to a new Delivery Point, the Authority, at its sole option, may agree to adjust the Customer's Firm Contract Demand on a month-to-month basis and/or to forego the application of the Section 4 (D) here in below, in order to allow the Customer and the Authority an adequate build-up or phase-in of operations; provided, however, that the Authority reserves the right to condition such agreement on such additional terms and conditions as the Authority deems appropriate for the circumstances.

(2) Except as otherwise provided herein or in the General Terms and Conditions, the Customer may reduce its Firm Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month period(s), to not less than 300 kW by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of service to the Delivery Point, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Firm Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Firm Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Firm Contract Demand for such year.

(d) For the fourth and subsequent twelve month period(s), the maximum reduction shall be 100% of the respective Firm Contract Demand(s) for such years.

Notices of such reductions in the Customer's Firm Contract Demand shall be irrevocable once given.

(3) The Customer's Firm Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rate Schedule or applicable rider(s) hereto under which the Customer also receives service, or (ii) by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional, special terms and conditions applicable to service to the Customer to be included in the aforementioned new Delivery Point Specification Sheet.

(4) Notwithstanding any other provisions hereof, in no event shall the Customer's Firm Contract Demand be less than the amount, if any, by which the sum of the Customer's then current contract demands under all applicable riders hereto is less than 1,000 kW.

(D) Excess Demand:

(1) The Customer's Excess On-Peak Billed Demand for each Billing Month shall be the greater of (a) that portion of the Customer's On-Peak Measured Demand for such Billing Month, if any, that exceeds the sum of (i) the Customer's then current Firm and Interruptible Billed Demand hereunder, and, where applicable, (ii) the Customers' Contract Demand(s), if any, under any and all applicable rider or riders to which the Customer also receives service from the Authority, exclusive of L-18-DRB or its successor.

(2) The Customer's Excess Off-Peak Demand for each Billing Month shall be that portion of the Customer's Off-Peak Measured Demand for such Billing Month, if any, that exceeds the sum of the Customer's then-current Off-Peak Maximum Demand and the Excess On-Peak Billed Demand above.

(3) Notwithstanding the foregoing or any other provision of this Rate Schedule or the General Terms and Conditions to the contrary, in the event that, at any time, (i) the Customer's rate of use of electricity at a Delivery Point exceeds the Customer's Maximum Demand applicable at that time, and (ii) the Customer fails to comply promptly with a request by the Authority to reduce such rate of use so as not to exceed such Maximum Demand, the Customer's Firm Contract Demand(s) for such Delivery Point for the current and subsequent Billing Months, shall at the Authority's sole option, be increased, from what it otherwise would have been, by the amount of such excess. In addition, in such event, the Customer shall be liable for any damage to the Authority's facilities caused by such excess. The Customer's Maximum Demand during Peak Demand Hours shall be equal to the sum of (i) the Customer's then current Firm Contract Demand hereunder and, where applicable, (ii) the Customer's then current Contract Demand(s), if any, under applicable riders hereto. The Customer's Maximum Demand in hours other than Peak Demand Hours shall be equal to the Customer's then current Off-Peak Maximum Demand.

(4) Notwithstanding the foregoing or any other provision of this Rate Schedule or the General Terms and Conditions, the Authority shall be under no obligation whatsoever to supply demands in excess of the Customer's aggregate Contract Demand(s), and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed the Customer's aggregate Contract Demands.

(E) Excess Reactive Demand:

The Customer's Excess Reactive Demand for each Billing Month shall be the amount, if any, by which the Customer's maximum 30-minute integrated reactive demand, in kilovars (kVAr), during such Billing Month exceeds 48.5% of the Customer's Measured Demand, in kilowatts (kW), for such Billing Month.

Section 5. Determination of On-Peak and Off-Peak Hours:

(F) Demand

(1) On-Peak Demand Hours

i. Summer On-Peak Demand Hours shall mean the hours from 1:00 p.m. to 10:00 p.m., Monday through Friday, for the months of May, June, July, August, and September.

ii. Non-Summer On-Peak Demand Hours shall mean the hours from 5:00 a.m.

to 9:00 a.m. and from 6:00 p.m. to 10:00 p.m., Monday through Friday, for all other months.

(2) Off-Peak Demand Hours

i. The Off-Peak Demand Hours are defined as all hours not specified above as On-Peak Demand Hours. The Authority may call for additional Off-Peak Demand Hours from time to time based on operational limitations or cost constraints. Additional Off-Peak Demand hours shall be designated at the sole discretion of the Authority.

(G) Energy

(H) .... On-Peak kWh are defined as all kWh consumed by the customer during the calendar months of June, July and August between the hours of 1PM and 10PM during weekdays (prevailing time).

(I) .... Off-Peak kWh are defined as all kWh consumed by the customer during all other hours of the year.

Section 6. Additional Terms and Conditions:

Service under this Rate Schedule, including service under all applicable riders hereto, is subject to the then currently effective General Terms and Conditions and the Service Agreement between the Customer and the Authority.

Adopted ____________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule L-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)

General Terms and Conditions
of
Large Power Electric Service

Section 1. Contract For Service

(A) As a condition precedent to the Authority supplying electric service under the Authority's Large Light and Power Rate Schedule L-17 and/or any and all riders thereto (collectively, "Schedule L"), to which these General Terms and Conditions are attached and made a part of, the Customer shall execute a Service Agreement in the form hereinafter provided as Exhibit I hereto. When executed by the Customer and the Authority, such Service Agreement, together with Schedule L, these General Terms and Conditions, and applicable notices of Contract Demands accepted by the Authority, shall constitute the entire contract for service between the Authority and the Customer.

(B) In the event of any conflict between these General Terms and Conditions and the provisions of the Service Agreement or Schedule L, the provisions of the Service Agreement or Schedule L shall govern.

(C) Nothing contained in any and all parts of Schedule L, the Service Agreement, and these General Terms and Conditions, shall be construed as affecting in any way the right of the Authority to make changes to any and all parts of such documents as provided by law.

(D) A separate Delivery Point Specification Sheet, in the form hereinafter provided as Exhibit II hereto, shall be prepared and executed by the Authority and the Customer for each Delivery Point at which the Customer is to receive service. Each such Delivery Point Specification Sheet, shall be deemed to be attached to, and made a part of, the Service Agreement between the Customer and the Authority.

(E) As used herein, "Delivery Point" refers to the point or points at which the electrical conductors (including bus bars) of the Authority are connected to the electrical conductors of the Customer or, in the case of service hereunder to a municipal or cooperative wholesale Customer of the Authority, to the conductors of that Customer or a retail customer of wholesale Customer. The Authority shall normally provide one three-phase service at a single voltage at each Delivery Point. Separate supplies for the same Customer at different locations and/or at different voltages shall be considered separate Delivery Points. Multiple Delivery Points shall be separately metered and billed.

Section 2. Conditions of Service

(A) The Authority's agreement to provide electric service on the date specified for electric service to each Delivery Point, subject to proper written notice as set forth in the applicable Rate Schedule, is contingent upon the Authority's ability to acquire, at a sufficient time prior to the date for commencement of such service, the necessary State and Federal approvals and the necessary rights of way and equipment for providing such electric service.

(B) With respect to facilities installed by the Authority to provide electric service to the Customer, the Authority reserves the right to use any available capacity of such facilities not needed for such service to supply other customers of the Authority.

Section 3. Electric Service Provided

(A) The Authority will provide electric service to Customer in the form of unregulated, three-phase alternating current at a frequency of approximately 60 Hertz.

(B) The Authority will provide electric service pursuant to the provisions of Schedule L at the nominal voltage desired by Customer provided such voltage is generally available in the area in which the electric service is desired. For Delivery Points existing on the date these General Terms and Conditions become effective, the nominal voltage supplied shall be the Authority's present nominal delivery voltage at such Delivery Points.

(C) The Authority will provide electric service for each Delivery Point at the nominal voltage specified in the Exhibit II to the Service Agreement for the Delivery Point, unless the Authority notifies the Customer in writing that the voltage will be changed to a specified higher or lower voltage in accordance with usual utility practices. In such cases, the Customer at the Customer's own expense will design, engineer, install, construct or modify, operate, and maintain facilities to such higher or lower voltage.

Section 4. Monthly Billing and Payment

(A) The Authority shall render to the Customer, after the end of each Billing Month, a bill setting forth the charges, as specified in Schedule L, for such Billing Month. "Billing Month" refers to a period between successive meter readings, which shall normally be once per month.

(B) All bills shall be on a net basis, and each such bill shall be due and payable in good funds at the office of the Authority in Moncks Corner, South Carolina, or at such other place as the Authority may designate, within ten (10) days after the date on which the bill is mailed or otherwise rendered. If payment is not received within twenty-five (25) days after the date the bill is mailed or otherwise rendered, the amount of the bill shall be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of one hundred dollars ($100.00), or two percent (2%) of the amount then outstanding including late payment charges. If payment is not made within thirty (30) days after the bill is mailed or otherwise rendered, the Authority may discontinue service until all past due bills are paid in full. Discontinuance of the service shall not relieve the Customer of any liability for the agreed Minimum Monthly Bill(s) for the period(s) of time service is so discontinued.

Section 5. Metering and Measurement

(A) Power and energy shall be metered by the Authority at, or as if at, each Delivery Point.

(B) Not less frequently than once each year, the Authority shall make periodic tests and inspections of meters installed by it. At the request of the Customer, the Authority shall make additional tests or inspections. Readings of metering instruments found to be in error by more than two percent (2%) either fast or slow will be corrected and credits or debits made to the Customer's account accordingly. Such correction shall apply for a period of not more than thirty (30) days prior to the date of test unless a longer period of inaccuracy can be definitely determined. The Customer shall pay all costs resulting from additional tests requested by the Customer if tests show meters to be accurate within two percent (2%).

Section 6. Use of Service

(A) Power shall be used in such manner as will not cause objectionable voltage fluctuations or other electrical disturbances on the Authority's system. If such fluctuations and disturbances become objectionable, the Authority may require the Customer, at the Customer's own expense, to install appropriate corrective equipment.

(B) The Service Agreement shall not be assigned by the Customer without approval in writing by the Authority. Service hereunder is exclusively for use by the Customer, and is not to be resold or shared with others. In consideration of the terms of the Service Agreement and these General Terms and Conditions, and in recognition of the fact that the supplying of power and energy from more than one source to the Customer's Facilities may adversely affect safety and the Authority's operations, the Customer agrees not to accept electrical service for said plant operations from any source other than the Authority during the terms of the Service Agreement.

Section 7. New Delivery Points

(A) To establish a new Delivery Point, the Customer must execute with the Authority a new Delivery Point Specification Sheet for the new Delivery Point prior to the date upon which the new Delivery Point is to be placed in service. Such new Delivery Point Specification Sheet shall be attached to, and made a part of, the Service Agreement and shall include any special provisions required for the establishment of the new Delivery Point. The execution of such Delivery Point Specification Sheet shall be a condition precedent to the Authority's supplying electric service to the Delivery Point.

(B) The Authority shall not be obligated to establish any new Delivery Point if it is reasonably determined by the Authority that, consistent with Prudent Utility Practice, the new Delivery Point is not necessary or appropriate for the delivery of power to serve load on the Customer's system.

(C) The Authority shall not be obligated to establish any new Delivery Point if after exercising due diligence the Authority cannot obtain all necessary State and Federal approvals, rights-of-way, and equipment. The Customer shall support all State and Federal filings that the Authority deems necessary (i) for supplying capacity and energy to the new Delivery Point, (ii) for the construction and permitting of the new Delivery Point, and (iii) such other facilities as the Authority deems necessary for the new Delivery Point.

(D) The Customer or potential Customer requesting the establishment of a new Delivery Point shall submit a detailed written request to the Authority specifying the requirements of such Delivery Point.

(E) Except as otherwise provided herein, the Customer is responsible for the installation, operation and maintenance of all necessary poles, lines, substations, transformers, switches, protective equipment, and other equipment (except the Authority's metering equipment) necessary for the establishment of a new Delivery Point, and for all facility rearrangements on the Customer's side of such Delivery Point that are required for the establishment thereof.

(F) Substantial and/or material modifications to an existing Delivery Point shall be deemed to constitute the termination of such Delivery Point and the establishment of a new Delivery Point.

Section 8. Delivery Points and Other Facilities

(A) The service specifications for each Delivery Point shall be as prescribed in the corresponding Delivery Point Specification Sheet.

(B) For each Delivery Point, the Customer shall provide, free of cost to the Authority, a suitable site on the premises for the installation by the Authority of equipment for rendering service hereunder. The Customer shall also provide for the safekeeping of this equipment and shall not permit anyone other than authorized employees and agents of the Customer and employees and agents of the Authority to have access thereto.

(C) The Customer hereby grants to the Authority for the entire term of this contract, free of cost, the right to construct, operate and maintain on property owned, leased or controlled by the Customer, all poles, conductors, appurtenances and equipment whatsoever reasonably necessary or desirable for supplying service hereunder to each Delivery Point. The Authority shall also have all rights of access to said property reasonably necessary or desirable for the aforesaid purposes and the right to remove all or any portion of the Authority's property at any time during the term of this contract or within a reasonable time thereafter. All property, structures and facilities erected by the Authority on property of the Customer are recognized and agreed by the parties to be removable trade fixtures, which shall be and remain personal property of the Authority whether affixed to the realty or not.

(D) Employees of the Authority shall be allowed access to the service installation site at all reasonable hours for the purpose of reading the metering instruments, inspecting the property of the Authority, removing such property, and for other purposes incident to the supplying of service to the Customer.

(E) All electrical facilities used or constructed by the Customer must conform to accepted modern practice and to applicable state and local requirements and must conform to the requirements of the National Electrical Safety Code and National Electrical Code.

(F) All facilities on the Customer's side of each Delivery Point shall be considered the system of the Customer, shall be paid for by the Customer, and shall be installed, operated, and maintained by the Customer at the Customer's expense; provided, that (i) the Authority's metering equipment, if any, located on the Customer's side of a Delivery Point will be owned, installed, operated, and maintained by the Authority; and (ii) the Authority shall have the right, at the Authority's option, to install and/or maintain such other facilities on Customer's side of a Delivery Point as the Authority may elect in the interests of system reliability.

(G) The Customer shall not utilize, or allow to be utilized, any equipment, appliance, or device that tends to unreasonably adversely affect the system of the Authority. The Customer shall maintain a reasonable electrical balance between the phases at each Delivery Point.

(H) The Customer shall install and maintain suitable protective devices on the Customer's system in order to afford reasonably adequate protection to the facilities of the Authority against adverse conditions or disturbances originating on Customer's system. Such protective devices shall be in accordance with the applicable industry standards relating to such equipment and with such other requirements as the Authority may reasonably deem necessary.

(I) The Authority shall install, own, operate, and maintain all lines and equipment located on the Authority's side of each Delivery Point, as well as the meter and metering equipment and, if applicable, any backup meter and metering equipment that may, at the Authority's option, be located on Customer's side of each Delivery Point. In such cases, Customer shall provide a location, acceptable to the Authority, for the installation of such metering equipment.

(J) In the event that the Customer requests the Authority to supply electricity in a manner requiring facilities in addition to or different from those normally provided by the Authority, the Authority will provide such facilities on the Authority's side of the Delivery Point, if practical to do so, provided the following conditions are met and a new Delivery Point Specification Sheet for such Delivery Point is executed to reflect these conditions:

1) The Customer requesting the facilities shall submit a detailed written request to the Authority specifying the type and kind of facilities;

2) The facilities are of a kind and type used by, or acceptable to, the Authority and are, installed in a place and in a manner acceptable to the Authority; and

3) The Customer agrees, in the Delivery Point Specification Sheet for the subject Delivery Point, to pay to the Authority the cost of the facilities prior to their installation or, at the Authority's sole option, appropriate Monthly Facilities Charges in lieu thereof, in addition to the other charges recoverable under Schedule L.

4) Meters and metering related equipment will be sized according to On-Peak Contract Demand, as specified by customer. Costs associated with metering and metering related equipment required to appropriately measure demand in excess of On-Peak Contract Demand will be the responsibility of the Customer. The Authority, as its sole option, may collect costs associated with meters and metering equipment, or upgrades associated therewith, within the appropriate Monthly Facilities Charge.

(K) In the event that the Customer's contract demand(s) under Schedule L (including any applicable riders thereto) is (are) reduced, nothing herein shall be construed as restricting the right of the Authority to change or reduce accordingly the capacity of the Authority's facilities serving the Customer.

(L) The Delivery Point Specification Sheet for each Delivery Point shall set forth appropriate provisions concerning the installation and maintenance of the Delivery Point and shall provide for adequate compensation to the Authority on termination of the Delivery Point by the Customer.

Section 9. Interruption of Service

(A) The Authority will make reasonable provisions to ensure satisfactory and continuous service but does not guarantee a continuous supply of electrical energy and shall not be liable for damage occasioned by interruptions of service or failure to commence delivery caused by an act of God, or the public enemy, or for any cause reasonably beyond the Authority's control, including, but not limited to, the failure or breakdown of generating or transmitting facilities, floods, fire, strikes or action or order of any agency having jurisdiction over the premises, or for interruptions that the Authority deems necessary for the inspection of, repair to, or changes to the Authority's facilities.

(B) Nothing herein shall be construed as restricting in any way the Authority's right to interrupt service to the Customer as the Authority may deem necessary or appropriate to facilitate inspection of, repair to, or changes to the Authority's facilities consistent with Prudent Utility Practice; provided, however, that the Authority shall use its reasonable best efforts, when practicable, to provide the Customer with advance notice of such interruptions and to coordinate with the Customer the times of such interruptions. In any event, failure of the Authority and the Customer to agree upon the time of such an interruption shall not restrict the Authority from proceeding therewith as the Authority deems necessary.

(C) The Customer shall provide written notification to the Authority immediately of any defects, trouble or accident which may in any way affect the delivery of power by the Authority to the Customer.

(D) Notwithstanding any provisions of Schedule L to the contrary, the Customer shall not be liable for any charges under this Schedule for any period during which he is unable to accept electric service due to strikes, fire, floods, or act of God or the public enemy.

(E) Both the Customer and the Authority shall use all due diligence in removing any causes which prevent the delivery or use of electrical power and energy hereunder.

(F) Any claims against the Authority resulting from an interruption of service shall be governed by the terms, conditions and limitations of the South Carolina Tort Claims Act, and any recovery in such claim shall not include indirect or consequential damages.

Section 10. Indemnity

All electrical power and energy provided for hereunder shall be the property of the Customer upon passing the Delivery Point(s) and the Customer shall have sole responsibility for the use, misuse or presence of said power and energy on the Customer's side of the Delivery Point(s). The Customer will indemnify and hold the Authority harmless from all claims, loss or expense arising from, or in any way connected with, the presence, use or misuse of electrical power and energy on the Customer's side of the Delivery Point(s).

Section 11. Determination of Contract Demands

The maximum amount, or amounts, of electric power and energy that the Authority agrees to sell, and that the Customer agrees to purchase at each Delivery Point (the Customer's "Contract Demand(s)") initially shall be set forth in the Delivery Point Specification Sheet for such Delivery Point. The initial establishment of, and subsequent changes to, such Contract Demand(s) shall be made only pursuant to the applicable provisions of Schedule L; provided, however, that the Authority reserves the right to require, for any Customer or potential Customer having a load of greater than 100,000 kW, notice requirements for changes in that Customer's Contract Demands(s) longer than those set forth in Schedule L.

Section 12. Term of Contract

(A) The Service Agreement, terminating on its effective date all prior agreements between the parties, shall become effective on the date specified therein, and shall remain in effect for an initial term of five (5) years, and thereafter for additional terms of two (2) years such, unless terminated by written notice of such intention from either party to the other at least one (1) year prior to the expiration date of the initial term or subsequent term; provided, however, that in no event shall the Service Agreement expire prior to (i) the expiration of the initial term as outlined above, or (ii) the reduction of the Customer's Contract Demand(s) to zero in the manner or manners specified in Schedule L. Nothing herein contained shall in any way bar the right of the Authority to collect any sums due it at the termination of the prior agreements.

If the Customer discontinues operations prior to the expiration of the initial term of the Service Agreement, or any subsequent term, or defaults under this Service Agreement in any respect and the Authority terminates the Service Agreement as a result of such default, the Customer agrees to pay to the Authority, on demand, a sum equal to the cumulative total of the Minimum Monthly Bills, as determined under Schedule L, for the remainder of the term of the Service Agreement, or any subsequent term.

(B) "Contract Year" shall be a twelve-month period beginning on the earlier of (i) the anniversary of the date service is initiated or (ii) the anniversary of the effective date of the Service Agreement.

(C) Schedule L and these General Terms and Conditions may be amended or revised by the Authority from time to time, in whole or in part, to reflect changed conditions, and when so amended or revised shall become effective as to all customers receiving service hereunder.

Section 13. Waiver

Any failure at any time by the Authority or the Customer to enforce a provision of Schedule L, these General Terms and Conditions, or the Service Agreement, shall not constitute a waiver by such party of said provision.

Section 14. Other Contracts

(A) Notwithstanding any other provision of Schedule L or these General Terms and Conditions to the contrary, an existing contract between the Authority and a Customer for the provision of service to such Customer pursuant to the Authority's Large Light and Power Rate Schedule that is in effect on the effective date of these General Terms and Conditions shall continue in full force and effect until its expiration. Such existing contract shall be deemed to constitute the Service Agreement between the Customer and the Authority hereunder until its expiration. In the event any provision of these General Terms and Conditions or Schedule L conflicts with a provision of such existing contract, the provision of the contract shall prevail.

(B) Upon the expiration of an existing contract between a Customer and the Authority, as described in the foregoing paragraph, continued service to such Customer shall be wholly subject to Schedule L and these Terms and Conditions.

(C) The establishment of a new Delivery Point, or the substantial modification of an existing Delivery Point, for a Customer having an existing contract, as described in the foregoing two paragraphs, shall require the termination of such existing contract and the execution of a new Service Agreement of the form specified in Exhibit I hereto.

(D) The terms and conditions of service to a Customer at a Delivery Point or Delivery Points under any rate schedule(s) or contract(s) other than Schedule L shall be unaffected by the terms of Schedule L and these General Terms and Conditions and shall be governed solely by the terms of such other rate schedule(s) or contract(s). The terms and conditions and service to each Delivery Point pursuant to Schedule L shall be governed solely by the provisions of Schedule L and these General Terms and Conditions and shall be unaffected by service, if any, to a Delivery Point or Delivery Points under any other rate schedule(s) or contract(s) between the Customer and the Authority.

(E) Acceptance of service under Schedule L without the benefit of an executed Service Agreement or another formal, written contract between the Customer and the Authority will bind the Customer to all terms and conditions of Schedule L and these General Terms and Conditions the same as if a formal written contract had been executed. In such event, all obligations hereunder shall begin on the date of such acceptance of service and shall continue for an initial term of five (5) years and thereafter for additional terms of two (2) years each, unless and until terminated at the end of such initial term or any additional term by no less than one (1) year's advance written notice of termination from either party to the other.

Adopted __________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule L-17, Attachment A, Effective April 1, 2017

Exhibit I

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
SERVICE AGREEMENT FOR LARGE POWER ELECTRIC SERVICE

This Agreement made and entered in this ______ day of ________________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and _________________________, hereinafter referred to as the "Customer."

W I T N E S S E T H:

That in consideration of the mutual covenants and agreements herein contained, the Authority and the Customer covenant and agree with each other as follows:

1. The Authority shall sell and deliver to the Customer, and the Customer shall purchase and receive from the Authority, the Customer's full requirements for electric service at the Delivery Point(s) specified in the respective Delivery Point Specification Sheets attached to this Service Agreement. Each such Delivery Point Specification Sheet shall, upon its execution, be a part of this Service Agreement, and shall include the service specifications for the provision of service at the corresponding Delivery Point.

2. A change in the service specifications at a Delivery Point shall require a new Delivery Point Specification Sheet to be executed to replace the previous Delivery Point Specification Sheet for that Delivery Point.

3. This Service Agreement adopts and incorporates by reference all of the provisions of the Authority's Large Light and Power Rate Schedule L-18 and all riders thereto (collectively, "Schedule L"), and its associated General Terms and Conditions, as such Schedule L and General Terms and Conditions may be changed from time to time.

4. The Customer shall pay the Authority monthly for electric service rendered hereunder pursuant to the applicable Rate Schedule and in accordance with the billing and payment provisions of Schedule L and the General Terms and Conditions.

5. This Service Agreement may not be assigned by either Party without the prior written consent of the other Party, provided, however, such consent shall not be unreasonably withheld.

6. If any provision of this Service Agreement is inconsistent with any provision of any applicable rate schedule or associated riders, the provisions of this Service Agreement shall prevail.

7. Subject to the provisions hereinbefore contained, this contract shall be binding upon and inure to the benefit of the successors and assigns of the parties hereto.

IN WITNESS WHEREOF, the Authority and the Customer have caused this Service Agreement for the Large Power Electric Service to be executed in duplicate in their names by their respective duly authorized officials, as of the day and year first above written.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ___________________________	**BY:** ___________________________
ATTEST:	_________________________________ **(CUSTOMER)**
BY: ___________________________	**BY:** ___________________________

Exhibit II

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
SERVICE AGREEMENT FOR LARGE POWER ELECTRIC SERVICE
DELIVERY POINT SPECIFICATION SHEET

1. Electric Service Supplied to:

2. Delivery Point Information:

   (a) Name:
   (b) Description:
   (c) Location:

3. Original Effective Date of Delivery Point:

4. Effective Date of this Specification Sheet:

5. Contract Demand(s):

   (a) Firm Power Contract Demand:
   (b) Interruptible Power Contract Demand:
   (c) Economy Power Contract Demand:
   (d) Standby Power Contract Demand
   (e) Demand Response Buy Back Demand

6. Electric Service Supplied: ____ volts (nominal) ____ Phase

7. Metering Data:

   (a) Metered Voltage:
   (b) Location:
   (c) Compensation:

8. Provisions for Special Facilities or Conditions:

IN WITNESS WHEREOF, the Authority and the Customer have each caused this Delivery Point Specification Sheet, which is to be incorporated into the Service Agreement for Large Power Electric Service, dated _____________, to be executed in their names by their respective duly authorized officials on this ___ day of ___________, 20__.

ATTEST:	**SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**
BY: ____________________________	**BY:** ____________________________
ATTEST:	____________________________________ **(CUSTOMER)**
BY: ____________________________	**BY:** ____________________________

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
INTERRUPTIBLE SERVICE
RIDER L-18-I

Section 1. Availability:

(A) Service hereunder, "Interruptible Power", is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-18 or its successor (hereinafter, "Schedule L"), to which this Rider L-18-I is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-18-I, the sum of the Customer's Contract Demands under this Rider L-18-I plus the Customer's Firm Contract Demand must equal or exceed 1,000 kW.

(C) The total amount of Interruptible Power available to all customers changes from time to time and the availability of such power hereunder is strictly subject to the provisions of this Rider L-18-I, including, without limitation, Section 4 (B)(4) herein below. As of January 1, 2012, the Authority has determined that Interruptible Power service will be made available to existing customers under contract and additional qualifying customers on a “first come first served” basis up to a maximum aggregate amount based on the Authority’s reserve requirement.

Section 2. Character of Service:

(A) Interruptible Power hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L that (i) is in excess of Firm Power purchased by the Customer under Schedule L and (ii) is interruptible or curtailable by the Authority in accordance with the following terms of this Rider.

(B) Curtailments by the Authority

(7) The Authority shall have the right, at any time or times and for any reason or reasons, to interrupt or call for curtailment of all or part of the Interruptible Power in response to an Emergency Event. As used herein, an “Emergency Event” means a condition on the Authority’s system in which, in the sole judgment of the Authority’s System Controller, action is required to maintain compliance with approved Reliability Standards or there is an imminent danger of deterioration of service to firm customers, voltage collapse, or damage to a part of the system.

(8) The Authority shall have the right, at any time or times and for any reason or reasons, to interrupt of call for curtailment of all or part of the Interruptible power in response to market or system conditions, hereinafter “Economic Curtailments”, not deemed Emergency Events. Such Economic Curtailments shall not exceed 250 hours, nor occur in more than 60 days, in any calendar year and, provided further, the number of such Economic Curtailments shall not exceed two (2) in any calendar day or 72 hours in any calendar week (Monday through Sunday.) Electrical power and energy purchased by the Customer pursuant to this section shall be classified as "Secondary Power."

(a) During the months of January, February, and December, the Authority reserves the right to curtail custumers for not longer than 48 consecutive hours. The Authority shall use good faith efforts to alert the Customer of such curtailment with at minimum 12 hours notification. With each such notification, the Authority shall supply the Customer with a quotation of the energy prices, in cents per kilowatt hour, applicable to power taken during the hours to which the notification applies. Curtailment hours shall be considered used when called.

(b) At any time or times, except as provided in Section 2(B)(2)(c) below, the Authority reserves the right to curtail customers for not longer than twelve (12) aggregate hours in any calendar day. Such curtailments shall occur independently from curtailments described in Section 2(B)(2)(a) above and such curtailments may occur during the same clock hour. In the event that the Authority deems it necessary and prudent to call for curtailment during the same clock hour for which another curtailment has been called, all provisions of the previous curtailment for the clock hour, including quoted prices and scheduled usage, shall be considered null and void.

(c) In the event that the Authority designates Economic Curtailments for greater than 24 continuous clock hours, the 12 hours immediately following the termination of the Economic Curtailment period shall be considered exempt from Economic Curtailments. Such limitation shall in no way restrict the duration of a single continuous Economic Curtailment period.

(d) In order to receive Secondary Power at a Delivery Point during an hour, the Customer shall respond to the Authority's notification for curtailment within a period of time to be established by the Authority, following such notice. Such responses shall include the maximum 30-minute integrated kW demand the Customer requests and is willing to receive during each period of time, hereinafter the interval, determined by the Authority, subject to its availability. The Authority, at it's option, may respond to and confirm agreement to the Customer's request or may not respond further, in which event such confirmation and agreement shall be deemed to have been given.

(e) As used herein, "Scheduled Secondary Demand" shall, for any hour, be the maximum 30-minute integrated kW scheduled for delivery to the Customer during such hour pursuant to this Rider L-18-I. "Delivered Secondary Demand", shall be the maximum 30-minute integrated kW demand by which the metered deliveries of power and energy to the Customer during the interval exceed theCustomer's then-current Firm Contract Demand under Schedule L.

(9) The Authority shall establish and maintain operational guidelines which shall state the conditions and circumstances under which calls for curtailments may be made. Such operational guidelines shall be published, and available for review, at the Authority's offices.

(4) When the Authority wishes to interrupt or curtail the Customer's Interruptible Power as provided herein, the Authority shall give notice thereof to the Customer by telephone or by such other means as the Authority may from time to time designate. Each such notice shall specify a demand level, which may be zero, to which the Customer's use of Interruptible Power is to be limited and the time period (hereinafter, a "Curtailment Period") to which such limitation is to apply. After receiving such a notice, the Customer shall, except as otherwise provided herein, limit the Customer's use of Interruptible Power during the Curtailment Period to which the notice applies, to the level specified by the Authority. Each such notice shall be deemed received by the Customer if the Authority shall have issued or attempted to issue that notice.

(5) The Authority will use reasonable efforts to give as much advance notice as practicable of probable curtailments when circumstances permit. The final scheduling of Emergency Event curtailments by the Authority will be postponed as long as practicable in order to minimize their occurrence and duration. Each notice issued by the Authority may be withdrawn or modified prior to the beginning of the potential Curtailment Period to which it applies. Such withdrawal or modifications shall be issued to the Customer by the same means as the original notices. Notices, if and to the extent so modified, shall be deemed to establish final Curtailment Periods and demand limitations. Notices withdrawn prior to the beginning of their respective Curtailment Period shall be without any further force or effect. The Authority shall confirm final notices of curtailment by subsequent letter to the Customer as soon as reasonably practicable after the end of the respective Curtailment Periods.

(6) After a notice of curtailment shall have been issued by the Authority, the Customer shall have the right to exceed the demand limitation set forth in the notice if, and only if, (i) the Customer makes a request to do so pursuant to the timetable established for the Curtailment Period to which the notice applies and the Authority, in its sole judgment, determines that it can supply the requested excess, and (ii) the Customer agrees to pay for such excess at the price(s) quoted by the Authority in response to such request. The Authority shall designate in writing from time to time a representative to whom such requests should be directed, and the Customer shall designate in writing from time to time a representative of the Customer who is authorized to make such requests and issue such agreements. Requests that are granted and the corresponding agreements to pay the quoted prices shall be confirmed in writing by the Authority as soon as is reasonably practicable after the corresponding Curtailment Periods have ended.

(7) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period that is not classified as Secondary Power shall be classified as Excess Power; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Power.

Section 3. Monthly Rates and Charges:

For all Interruptible Power provided hereunder, the monthly charge shall consist of the following charges:

(A) Interruptible Power:

For all services provided hereunder other than Secondary Power and Excess Power:

(1) Monthly Demand Charge:

(a) All kW of Interruptible Billing Demand @ $10.31/KW

(f) For each kW of Interruptible Billing Demand, a charge or credit, if any, determined from time to time pursuant to the Authority's Demand Sales Adjustment Clause DSC-18, or its currently applicable successor clause, if any.

(g) Economic Development Sales Adjustment:

For each kW of Firm Billing Demand, a credit, if any, determined from time to time pursuant to the Authority's Economic Development Sales Adjustment Clause (EDA-18), or its currently applicable successor clause, if any.

(2) Monthly Energy Charge:

(a) Base Energy Charge:

On-Peak kWh @ $0.0575/kWh
Off-Peak kWh @ $0.0375/kWh

(b) Fuel Adjustment Charge:

For each kWh, the charge or credit per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-18, or its successor clause, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(B) Secondary Power:

(5) The price for Secondary Power used by the Customer in each Curtailment Period shall be the price quoted by the Authority for such power and energy as hereinabove described. Each such quotation shall be based on the Authority's reasonable best estimate of its incremental costs of supplying such Secondary Power, plus a margin of 15% above the Authority's incremental costs.

(6) Scheduling

a. Overscheduling charges shall equal the amount, if any, by which the Customer's Delivered Secondary Demand for the hour was less than 80 percent (80%) of the Customer's Scheduled Secondary Demand for the interval, times 15% of the quoted energy price for the interval times the number of clock hours in the interval. Charges shall not apply to Delivered Secondary Demand within 100 kW of the Customer's Scheduled Secondary Demand for that interval.

b. Underscheduling charges shall equal the amount, if any, by which the Customer's Delivered Secondary Demand for each Economic Curtailment interval exceeds the Customer's Scheduled Secondary Demand for the interval, times 150% of the quoted price for the interval times the number of clock hours in the interval.

c. During a single continuous Economic Curtailment and in lieu of Underscheduling and Overscheduling charges listed in hereinbefore, the total Overscheduling and Underscheduling charges may be levied on the net difference between Delivered Secondary Demand and Scheduled Secondary Demand each interval during the curtailment. Applicable charges for this demand shall be levied at the average quoted price for energy taken during the curtailment period and the average number of interval hours. Such charges shall be at the sole discretion of the Authority.

(C) Excess Power:

The price for Excess Power used by the Customer in each Emergency Event Curtailment Interruption Period as defined in Section 2(B)(1) shall be 150% of the Authority's reasonable best estimate of its incremental cost (including opportunity costs) of supplying such Excess Power. Such incremental costs may include both demand-related and energy-related costs.

In addition, whenever the Customer shall have used Excess Power during an Emergency Event Curtailment Period as defined in Section 2(B)(1), the provisions of Section 4(C) below shall apply.

Section 4. Determination of Demands:

(A) Interruptible Billing Demand

The Customer's Interruptible Billing Demand for each Billing Month shall be the amount, if any, by which the Customer's Measured On-Peak Demand for such month, determined pursuant to Section 4(B) of Schedule L, exceeds the Customer's then-current Firm Billed Demand, under Schedule L, however, that in no event shall such Interruptible Billing Demand be (i) greater than 100% of the interruptible contract demand or (ii) less than 80 percent (80%) of the sum of the Customer's then-current Firm and Interruptible Contract Demand less Firm Billed Demand.

As used in Section 4(A) only, Firm Billed Demand shall include an adjustment for energy billed under Section 3(B)(2)(b) of Schedule L. Such adjustment shall be calculated monthly utilizing the following formula:

*Off-Peak Demand = (Off-Peak Energy / Off-Peak Hours) * 1.5*

where Off-Peak Energy means all energy billed under Section 3(B)(2)(B) of Schdule L and Off-Peak Hours means the total number of Off-Peak demand hours for the month under Section 5(A)(2) of Schedule L.

(B) Interruptible Contract Demand

(1) Except as otherwise provided herein, the Customer's Interruptible Contract Demand shall be the maximum amount of Interruptible Power, in kilowatts, that the Customer has requested and the Authority has agreed to supply, as evidenced in the Delivery Point Specification Sheet for which the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer may reduce its Interruptible Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month periods, by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of the Service Agreement between the Customer and the Authority, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Interruptible Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Interruptible Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Interruptible Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Interruptible Contract Demand(s) for such years.

Notices of such reductions in the Customer's Interruptible Contract Demand shall be irrevocable once given.

(3) The Customer's Interruptible Contract Demand, once established or reduced, may be increased only by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(4) The total amount of Interruptible Power available for sale to all customers changes from time to time. In initially determining the amount of Interruptible Power, if any, to provide a Customer

and/or in determining the amount, if any, by which a Customer's Interruptible Contract Demand may be increased, the Authority shall take into account the total amount of such Interruptible Power it reasonably expects to be available and its prior commitments for sales of such power. If, and to the extent that, the Authority thus determines it can make additional Interruptible Power available to new Customers and to existing Customers, the Authority shall do so on a first-come, first-served basis, in accordance with the stated limit of Interruptible Power specified in Section 1 (C) herein.

(C) Excess Demands

(1) In the event the Customer's use of service during any Emergency Event Curtailment Period exceeds the demand level established by the Authority for such Curtailment Period, the Customer's Interruptible Contract Demand shall be reduced, and the Customer's Firm Contract Demand shall be increased, by the greatest 30-minute integrated demand of such excess. In such event, such reduction and such increase each shall apply for the current Billing Month and the subsequent eleven (11) Billing Months.

(2) Notwithstanding the foregoing or any other provision of this Rider L-18-I, Schedule L, or the General Terms and Conditions attached thereto, the Authority shall be under no obligation whatsoever to supply demands in excess of the demand level established by the Authority during a Curtailment Period, and nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit the Customer's demand so as not to exceed such demand level.

Section 5. Other Terms and Conditions:

Service under this Rider L-18-I, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Adopted ____________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule L-17-I, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
ECONOMY POWER SERVICE
RIDER L-18-EP

Section 1. Availability and Applicability

(A) Service hereunder, "Economy Power," shall be available to customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-18 or its successor (hereinafter, "Schedule L"), to which this Rider L-18-EP is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-18-EP, the sum of the Customer's Contract Demands under this Rider L-18-EP plus the sum of the Customer's Firm Contract Demand and Interruptible Contract Demand must equal or exceed 2,000 kW.

Section 2. Character of Service

(A) Economy Power hereunder shall consist of the supply of electric power and energy, of the same general characteristics as described in Schedule L, that the Authority may from time to time, in its sole discretion, determine to be available from the Authority's resources (including the Authority's arrangements with other utilities) in excess of the power and energy requirements of the Authority's other customers.

(B) The Authority shall use good faith efforts to notify the Customer of the availability of Economy Power in each clock hour prior to the beginning of such hour through a means established by the Authority from time to time. With each such notification, the Authority also shall supply the Customer with a quotation of the Economy Energy Price, in cents per kilowatt hour, applicable to Economy Power during the hour to which the notification applies.

(C) In order to receive Economy Power at a Delivery Point during an hour, the Customer shall respond to the Authority's notification for such hour within a period of time, to be established by the Authority, following such notice. Such response shall include the amount of Economy Power the Customer requests and is willing to receive in the applicable hour, subject to its availability. The Authority, at its option, may respond to confirm agreement to the Customer's request or may not respond further, in which event such confirmation and agreement shall be deemed to have been given.

(D) The Authority shall use its reasonable best efforts, but shall be under no obligation whatsoever, to provide periodic estimates of the expected availability and price of Economy Power for upcoming hours and upcoming days. However, such estimates shall be estimates for preliminary planning purposes only, shall be subject to change without notice, and shall have no force or effect. To facilitate the Authority's planning and the aforementioned estimates, the Customer, at the request of the Authority, shall promptly provide the Authority with the Customer's best reasonable estimate of the Customer's requirements for Economy Power in upcoming hours and days. However, such estimates shall be for preliminary planning purposes only, shall be subject to change without notice, and shall have no force or effect.

(E) As used herein, "Scheduled Economy Energy" shall, for any hour, be the amount, if any, of Economy Power scheduled for delivery to the Customer during such hour pursuant to this Rider L-18-EP. "Delivered Economy Energy", for any hour or half-hour, shall be the amount, if any, by which the metered deliveries of power and energy to the Customer in such hour or half-hour exceed the sum of (i) the Customer's then-current Firm Contract Demand under Schedule L, and (ii) the Customer's then current Interruptible Contract Demand, if any, pursuant to Rider L-18-I, but in no event greater than the Customer's then current Economy Power Contract Demand hereunder.

(F) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period identified in Section 4 (B)(2) shall be classified as Excess Economy Power; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Economy Power.

Section 3. Monthly Rates and Charges

Charges to the Customer for Economy Power hereunder shall be equal to the sum of (i) the Monthly Customer Charge, (ii) the Monthly Reservation Charge, (iii) the Monthly Energy Charge, and (iv) the Monthly Excess Economy Power Demand Charge, all as set forth below:

(A) Monthly Customer Charge

The Monthly Customer Charge hereunder shall be $1,000.00 per month for each Billing Month.

(B) Monthly Reservation Charge

The Monthly Reservation Charge hereunder shall be equal to the Customer's Economy Power Contract Demand for such Billing Month, in kilowatts, times $1.87 per kilowatt.

(C) Monthly Energy Charge

The Monthly Energy Charge hereunder shall be the aggregate sum of all applicable Hourly Energy Charges during the Billing Month. Each such Hourly Energy Charge shall be the sum of (1), (2), and (3) below for such hour:

(1) The amount, if any, of Delivered Economy Energy up to the amount of Scheduled Economy Energy for the hour times the Economy Energy Price for that hour;

(2) Overscheduling charges shall equal the amount, if any, by which the Customer's Delivered Economy Energy for the hour was less than 90% of the Customer's Scheduled Economy Energy for the hour, times the Capital Improvement Fund and generation-related charges in the Economy Energy Price as stated in Section 3(C)(3) below; and

(5) Underscheduling charges shall equal he amount, if any, by which the Customer's Delivered Economy Energy for the hour exceeded the Customer's Scheduled Economy Energy for the hour, times 150% of the Economy Energy Price for the hour. In the event that the Authority determines the Economy Energy Price for the hour does not sufficiently recover the costs to serve such excess power, the Authority reserves the right to charge 150% of the Authority's best reasonable estimate of the actual incremental cost to serve. Such decision shall be at the sole discretion of the Authority.

In addition, whenever the Customer shall have used Excess Economy Power during a Curtailment Period, the provisions of Section 4 (B) below shall apply.

For each hour, the aforementioned Economy Energy Price applicable to Economy Power hereunder shall be the price quoted by the Authority for the hour pursuant to Section 2 hereof. For each hour, such Economy Energy Price shall be the greater of (i) the Authority's Incremental Energy Cost, plus markups to include contributions to the Capital Improvement Fund, transmission losses, and generation-related expenses, or (ii) the price at which the Authority could have sold such Economy Power to another utility or utilities, based on actual quotes from such other utility or utilities. Such Incremental Energy Cost shall be the Authority's best reasonable estimate of its out-of-pocket, incremental cost of producing Economy Power during such hour, as determined in accordance with usual utility practice. In no event shall the final Economy Energy Price quoted by the Authority for an hour be subject to after-the-fact adjustment except as allowed in this.
For the purposes of the L-18-EP Economy Energy Price, contributions to generation-related expenses shall equal $8.48/MWH.

For the purposes of the L-18-EP Economy Energy Price, contributions to the Capital Improvement Fund and transmission losses shall equal the Authority's Incremental Energy Cost times a factor of 0.1233. Such charges may be modified from time-to-time.

(D) Monthly Excess Economy Power Demand Charge

The Monthly Excess Economy Power Demand Charge hereunder shall be equal to (i) the greatest 30-minute integrated kW demand of Excess Economy Power, multiplied by (ii) six (6) times the sum of the per-kW rates for the Firm Base Demand Charge and the Excess Demand Charge specified in Schedule L.

(E) Optional Charge(s)

From time to time, at its sole discretion, the Authority may elect to offer customers served under this Rider pricing alternatives. The Optional Charge(s) hereunder shall be set forth along with the terms and conditions of each alternative in writing. The Customer, at its sole discretion, shall have the choice of receiving any portion of Economy Energy under the Optional Charge(s).

Section 4. Determination of Demands

(A) Economy Power Contract Demand

(1) The Customer's Economy Power Contract Demand for each Delivery Point shall be established initially by mutual agreement of the Authority and the Customer, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer's Economy Power Contract Demand may be unilaterally reduced by the Customer, in whole or in part, such reduction to become effective at the beginning of a Billing Month specified by the Customer if, and only if, the Customer shall have provided the Authority with at least twenty-four (24) months prior written notice of such reduction. Notices of such reductions in the Customer's Economy Power Contract Demand shall be irrevocable once given.

(3) The Customer's Economy Power Contract Demand, once established or reduced, may be increased only (i) pursuant to the terms of this Rider L-18-EP, or (ii) by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require that additional, special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(B) Excess Demands

(1) The amount of Economy Power requested by the Customer in an hour shall be subject to pro rata reduction in the event the Authority determines, in its sole judgement, the aggregate amount of Economy Power so requested by the Customer and all other such customers exceeds the total amount available for such hour. In such event, the Authority shall so notify the Customer prior to the beginning of such hour, and the prorated amount requested by the Customer shall be deemed to supersede the Customer's prior request and shall be deemed to constitute the agreed-upon amount of Economy Power for delivery to the Customer's Delivery Point for that hour, unless the Customer, prior to the beginning of the hour, withdraws its request altogether after receiving such notice from the Authority.

(2) Notwithstanding any other provision of this Rider L-18-EP or Schedule L to the contrary, the Authority shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time that the Authority, in its sole judgement, determines that (i) such Economy Power is no longer available and that continued use thereof by Customer will adversely affect service to the Authority's other customers and/or other utility systems with which the Authority is interconnected, or (ii) circumstances on the Authority's system and/or the systems of any other utility with which the Authority has an interchange arrangement are such that the Authority is unable to supply Economy Power at the Energy Price previously noticed by the Authority. When the Authority calls for such a curtailment, the amount of Economy Power scheduled for delivery to the Customer shall be deemed to be reduced accordingly.

(3) The Authority shall be under no obligation whatsoever to supply Economy Power in an hour in excess of the amount scheduled for delivery to the Customer as herein provided. Nothing herein shall be construed as restricting the right of the Authority to take such steps as the Authority may deem necessary, including without limitation complete interruption of service to the Customer, to limit deliveries to the Customer to the amounts so scheduled.

Section 5. Other Terms and Conditions

Service under this Rider L-18-EP, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Adopted _____________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes: Schedule L-17-EP,
Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVIC AUTHORITY
(SANTEE COOPER)
L-18-EP-O
Economy Power Service Rider
Optional Energy Charge

Section 3(E) of Rider L-18-EP provides that the Authority may offer pricing alternatives to customers served under the Rider. In accordance with this provision, the Authority offers an Optional Energy Charge as set forth below.

Notwithstanding any provision of L-18-EP to the contrary, an Economy Power (EP) customer, at its sole discretion, may elect to receive its entire Economy Power Service under the following terms and conditions.

e) The monthly Reservation Charge hereunder shall be equal to the Customer's Economy Power Contract Demand for such billing month, in kilowatts, times $3.75 per kilowatt.

f) The Hourly Energy Charge during Off-Peak Periods shall be:

(1) Base Energy Charge:

All kWh @ ………………………………………… $0.0375/kWh

(2) Fuel Adjustment Charge:

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-18, or its successor clause, with "Fb/Sb" and "K" of the formula in said clause being equal to $0.03641/kWh and 0.085, respectively.

The Hourly Energy Charge during On-Peak Periods shall be determined as set forth in section 3(C) of the L-18-EP Rider, or its successor.

c) For the purposes of this pricing alternative, "Off-Peak Periods" shall consist of all time periods not designated as On-Peak Periods. Except as provided for in Sections (d) and (e) herein, "On-Peak Periods" shall normally consist of the hours specified in the following table:

Season	On-Peak Hours
Summer (May – September)	11:00 a.m. – 11:00 p.m.
Winter (January, February, November, December)	5:00 a.m. – 11:00 a.m. 5:00 p.m. – 11:00 p.m.
March, April and October	All Off-Peak

d) During the months of January February, and December, the Authority reserves the right to designate additional On-Peak hours as set forth below:

(7) When the Authority determines that its estimated system daily peak demand will be greater than 90% of the projected system peak demand for that winter season (based on the Authority's most recent load forecast), then the Authority may, at its option and

with day ahead notice, designate up to twelve additional hours per day as On-Peak hours.

(8) If the Authority, in accordance with the criteria set forth in Section (d)(1) above, finds it necessary to designate additional On-Peak hours, it will notify affected customers by 12:00 noon on the current day for the following business or non-business day(s).

(9) The ability of the Authority to designate additional On-Peak hours in accordance with this Section (d) shall be limited to no more than seven days per month in each of these months.

e) During the months of March, April and October, the Authority reserves the right to designate additional On-Peak hours as set forth below:

(7) When the Authority projects its Incremental Energy Cost, as set forth in the Economy Power Service Rider, L-18-EP, or its successor, will equal or exceed $55.00/MWh, then the Authority may, at its option and with day ahead notice, designate up to twelve hours per day as On-Peak hours.

(8) If the Authority, in accordance with the criteria set forth in Section (e)(1) above, finds it necessary to designate additional On-Peak hours, it will notify affected customers by 12:00 noon on the current day for the following day.

(9) The ability of the Authority to designate additional On-Peak hours in accordance with this Section (e) shall be limited to no more than seven days per month in each of these months.

f) The Customer will continue to schedule all Economy Energy usage during Off-Peak Periods; failure to schedule may result in discontinuance of this pricing alternative by the Authority to the Customer.

g) Unless specifically contradicted above, all other provisions of Rider L-18-EP, or its successor, remain in effect. The Authority, in its sole judgment, shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time.

h) This pricing alternative is in effect until modified or withdrawn. This pricing alternative is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted ______________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
L-17-EP Economy Power Service Rider
Optional Energy Charge, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVIC AUTHORITY
(SANTEE COOPER)
L-18-EP-AU
Experimental Economy Power Service Rider
As-Used Billing Option

Section 3(E) of Rider L-18-EP provides that the Authority may offer pricing alternatives to customers served under the Rider. In accordance with this provision, the Authority offers an As-Used Billing Option as set forth below.

Service hereunder shall be limited to ten percent (10%) of the customer's total contract demand. Total contract demand shall refer to the sum of the Firm Contract Demand plus the Customer's Contract Demand(s) (if any) under any and all riders hereto and other rate schedules of the Authority, exclusive of Nominated or curtailed capacity as provided under L-18-DRB.

Notwithstanding any provision of L-18-EP to the contrary, an Economy Power (EP) customer, at its sole discretion, may elect to receive its entire Economy Power Service under the following terms and conditions, subject to the limitation above.

g) Service taken under this rider shall not be subject to the Monthly Reservation Charge as defined in Section 3(B) of the L-18-EP rider.

h) The Hourly Energy Charge during On-Peak Periods shall be determined as set forth in Section 3(C) of the L-18-EP Rider, or its successor.

i) The Hourly Energy Charge shall include a charge equal to $0.02175/kWh in addition to all the applicable Hourly Energy Charges listed above.

b) For the purposes of this pricing alternative, "On-Peak Periods" shall consist of the time periods set forth in Section 5(A) of Schedule L-18 or it's successor.

c) Energy taken under this pricing alternative shall not be available during off-peak periods, including any additional off-peak hours as set forth in Section 5(A)(2) of Schedule L-18 or it's successor.

d) Unless specifically contradicted above, all other provisions of Rider L-18-EP, or its successor, remain in effect. The Authority, in its sole judgment, shall be able to call for partial or complete curtailment of receipt of Economy Power by the Customer at any time.

f) This pricing alternative is in effect until modified or withdrawn. This pricing alternative is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted ______________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Supersedes: Schedule L-17-EP-AU,
Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
STANDBY SERVICE
RIDER L-18-SB

Section 1. Availability

(A) Service hereunder, "Standby Power", is available to those customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-18 or its successor (hereinafter, "Schedule L"), to which this Rider L-18-SB is attached and made a part of. In addition, service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(B) In order to receive service under this Rider L-18-SB, the sum of the Customer's Firm Contract Demand and Interruptible Contract Demand must equal or exceed 1,000 kW.

(C) Standby Power shall be that power used to provide standby or replacement service which, in the opinion of the Authority, the Authority has available at any location, to a Customer having another source of electrical power not held solely for emergency use, or another source of electrical power for peak-shaving purposes, both for which the Authority's service may be substituted directly or indirectly.

Section 2. Character of Service

(A) Standby Power hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L that (i) is in excess of Firm Power purchased by the Customer under Schedule L; and Interruptible Power, if any, purchased by the Customer under Rider L-18-I; and Economy Power, if any, purchased by the Customer under Schedule L-18-EP, and (ii) is deemed, in the opinion of the Authority, to be available for use by the Customer.

(B) The Customer shall use its best reasonable efforts to coordinate its requirements for Standby Service with the Authority, including (but not limited to) scheduling maintenance outages of Customer-owned generation to occur at times agreeable to the Authority. In no event shall the Authority be required to supply Standby Service at times when it shall have interrupted or curtailed service to any other retail customer. In no event shall the Authority be required to supply Standby Service on more than sixty (60) days out of any twenty-four (24) consecutive months.

Section 3. Monthly Rates and Charges

The monthly charge for Standby Power shall consist of the following charges:

(A) Monthly Standby Reservation Charge

The Monthly Standby Reservation Charge hereunder shall be equal to the Customer's Standby Power Contract Demand for such Billing Month, in kilowatts, times $3.75 per kilowatt.

(B) Monthly Standby Demand Charge

All kW of Standby Billing Demand @ $14.69/kW

(C) Monthly Energy Charge

The Monthly Energy Charge for Standby Power Service shall be calculated by multiplying the total amount of kilowatt-hours of Standby Power delivered to the Customer during the current month by the Monthly Standby Power Energy Rate for such month. The Monthly Standby Power Energy Rate for a month shall be the sum of (i) the Authority's Average Monthly Fossil Fuel Cost Rate and (ii) the Authority's then current Non-Fuel Energy Cost, both as hereinafter defined.

The Authority's Average Monthly Fossil Fuel Cost Rate for each month shall be determined by the following formula:

$$F = 100 * (Fm/Gm) * (1/(1-K)) * (1/(1-L))$$

where:

F = Average Monthly Fossil Fuel Cost Rate in cents per kilowatt-hour, rounded to the nearest one-thousandth of a cent.

Fm = the Authority's total dollar fossil fuel cost for the current month, which shall be equal to the sum of:

(a) the cost of fossil fuel burned or used, including the net cost of allowances expensed concurrent with regulated emissions, in the Authority's own plants and the Authority's share of fossil fuel burned or used in jointly owned or leased plants as such costs are recorded in Accounts 501, 509, and 547; plus

(b) the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the authority to substitute for its own higher cost energy; plus

(c) the actual identifiable fossil fuel cost associated with energy purchased for reasons other than identified in (b) above; less

(d) the cost of fossil fuel recovered through inter-system sales including, without limitation, the fuel cost related to economy sales and other energy sold on an economic dispatch basis.

Gm = the Authority's fossil net generation, in kilowatt-hours, for the current month, which shall be equated to the sum of:

(a) the net generation of the Authority's own fossil-fueled plants and the Authority's shares of jointly owned or leased fossil-fueled plants; plus

(b) interchange in; plus

(c) the fossil-generated energy purchased by the Authority other than interchange; less

(d) the net fossil-fueled generation associated with inter-system sales referred to in Fm(d) above.

K = the Authority's allowance for capital improvements, which, for the purposes of this Rider, shall be nine percent (9.0%), expressed as a decimal fraction.

L = the Authority's allowance for transmission and distribution system losses applicable to service to the Customer, expressed as a decimal fraction.

The Authority's Non-Fuel Energy Cost shall be the rate, in cents/kWh, obtained by subtracting (a) the product of (i) 1/(1-K), where "K" is defined above, and (ii) the base fuel cost (Fb/Sb) contained in the Authority's then applicable Fuel Adjustment Clause (FAC) from (b) the Energy Charge set forth in the Authority's then applicable Large Light and Power Rate Schedule (Schedule L).

Section 4. Determination of Demands

(A) Standby Power Billing Demand

The Customer's Standby Power Billing Demand for each Billing Month shall be the amount, if any, by which the Customer's Measured Demand for such month, determined pursuant to Section 4(B) of Schedule L, exceeds the sum of (i) the Customer's then-current Firm Contract Demand, under Schedule L, and (ii) the Customer's Economy Power Contract Demand, if any, under Rider L-18-EP; provided however, that in no event shall such Standby Billing Demand be greater than the Customer's Standby Power Contract Demand. Any Measured Demand exceeding the Customer's total Contract Demand for such month shall be Excess Demand in accordance with Section 4(D) of Schedule L.

If a Customer fails to satisfy the requirements of Section 2(B) above, the Authority may, at its sole option, require the Customer to pay for all Standby Billing Demand at the rate specified in Section 3(A)(2)(a) of Schedule L, until such time as the Customer satisfies the constraints of Section 2(B) above.

(B) Standby Power Contract Demand

(1) Except as otherwise provided herein, the Customer's Standby Power Contract Demand shall be the maximum amount of Standby Power, in kilowatts, that the Customer has requested and the Authority has agreed to supply, as evidenced in the Delivery Point Specification Sheet for which the Delivery Point that is attached to, and a part of, the Service Agreement between the Customer and the Authority.

(2) The Customer may reduce its Standby Power Contract Demand for a Delivery Point, for any twelve month period and subsequent twelve month periods, by providing prior written notice of such reduction to the Authority at least one year prior to the beginning of the first period to which the notice applies; provided, however, that (i) no such reduction shall become effective before the fifth anniversary of the Service Agreement between the Customer and the Authority, and provided further that (ii) the greatest amounts of such reductions shall be as follows:

(a) For the first twelve month period to which such notice applies, the maximum reduction shall be the greater of 5,000 kW or 25% of the Standby Power Contract Demand for such year.

(b) For the second succeeding twelve month period, the maximum reduction shall be the greater of 10,000 kW or 50% of the Standby Power Contract Demand for such year.

(c) For the third succeeding twelve month period, the maximum reduction shall be the greater of 15,000 kW or 75% of the Standby Power Contract Demand for such year.

(d) For the fourth and subsequent twelve month periods, the maximum reduction shall be 100% of the respective Standby Power Contract Demand(s) for such years.

Notices of such reductions in the Customer's Standby Power Contract Demand shall be irrevocable once given.

(3) The Customer's Standby Power Contract Demand, once established or reduced, may be increased only by mutual agreement between the Authority and the Customer evidenced by the execution of a new, revised Delivery Point Specification Sheet for the Delivery Point to which the increase is to apply. The Authority shall be under no obligation to agree to any such increase but shall give good faith consideration to each such request. In such an event, the Authority may require additional special terms and conditions applicable to service to the Customer be included in the aforementioned new Delivery Point Specification Sheet.

(4) The total amount of Standby Power available for sale to all customers changes from time to time. In initially determining the amount of Standby Power, if any, to provide a Customer and/or in determining the amount, if any, by which a Customer's Standby Power Contract Demand may be increased, the Authority shall take into account the total amount of such Standby Power it reasonably expects to be available and its prior commitments for sales of such power. If, and to the extent that, the Authority thus determines it can make additional Standby Power available to new Customers and to existing Customers, the Authority shall do so on a first-come, first-served basis.

Section 5. Other Terms and Conditions

Service under this Rider L-18-SB, is subject to the terms of the currently effective Schedule L, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted ___________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule L-17-SB, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
LARGE LIGHT AND POWER
DEMAND RESPONSE BUY BACK (DRB)
SCHEDULE L-18-DRB

Section 1. Limited Availability

(G) Service hereunder, "Demand Response Buy Back," is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-18 or its successor (hereinafter, "Schedule L"). In addition, service hereunder shall be available only to specified Delivery Points upon a prior written Service Agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(H) In order to receive service under this Schedule:

1. The sum of the Customer's Contract Demand under this Schedule L-18-DRB plus the Customer's Firm Contract Demand must equal or exceed 1,000 kW,

2. The Customer's electrical wiring permits separate metering of the Customer's equipment and facilities,

3. The Customer's designated equipment and facilities must be totally and responsively interruptible at the direction of the Authority or its designated representatives,

4. The Customer, at its expense, shall cause the following to be installed:

a) Dedicated telephone and data lines for the exclusive use of the Customer and the Authority,

b) All communications and control equipment required by the Authority,

c) Separate metering provided by the Authority to enable the Authority to separately meter the Customer's designated equipment and facilities.

5. The Customer agrees to hold the Authority and its designated representatives harmless from any and all claims, for damages resulting from interruption or curtailment of electric service provided under this Schedule. (See Section 7 - Special Provisions.)

(I) The total amount of Demand Response Buy Back service available to all qualifying customers shall be determined solely by the Authority and such amount changes from time-to-time. As of January 1, 2012, the Authority has determined that Demand Response Buy Back service will be made available to qualifying customers on a "first come first served" basis up to a maximum aggregate amount of 300 MW.

Section 2. Character of Service

Demand Response Buy Back hereunder shall be electrical power and energy of the same general characteristics as described in Schedule L and Interruptible Service Rider L-18-I that is interruptible or curtailable by the direction of the Authority in accordance with the following terms:

(O) Demand Response Buy Back shall be interruptible or curtailable service with a short Customer notice and short interruption duration that is applicable to the Customer's equipment and facilities. Short notice will be two (2) minutes or less with usual customer notification and short duration will be limited to sixty (60) minutes from the onset of the interruption or curtailment.

(P) During a System Disturbance or Emergency, Demand Response Buy Back service shall typically be the first type of service to be interrupted or curtailed and interruption and curtailment will be ratably administered among Customers receiving such service as determined by the Authority (see Operational Guidelines for Curtailment and/or Interruption of Curtailable or Interruptible Loads).

(Q) The Authority shall have the right, at any time or times and for any reason or reasons, to direct the interruption of all or part of the Demand Response Buy Back service, provided that the duration of such interruptions or curtailments is sixty (60) minutes or less, shall not exceed 200 hours, not occur in more than 60 days, in any calendar year and, provider further, that the number of interruptions or curtailments, other than during System Emergencies, shall not exceed two (2) in a calendar day. As used herein, a "System Disturbance or Emergency" means a condition on the Authority's system in which, in the sole judgment of the Authority's System Controller or designated representative, action is required to maintain compliance with approved Reliability Standards, or there is an imminent danger of deterioration of service to firm or higher priority customers, voltage collapse, or damage to a part of the system. The Authority shall establish and maintain operational guidelines (referenced above), which shall state the conditions and circumstances under which directions for interruptions and curtailments may be made. Such operational guidelines shall be published, and available for review, at the Authority's offices.

(R) When the Authority determines that a System Disturbance or Emergency is imminent or exists and/or determines the need to interrupt or curtail the Customer's Demand Response Buy Back service as provided herein, the Authority shall give notice thereof to the Customer by telephone or by such other means of communication as the Authority may from time-to-time designate. Each such notice shall specify a demand level of Demand Response Buy Back service, to which the Customer's use of Demand Response Buy Back service is to be limited and the anticipated time period (hereinafter, a "Curtailment Period") to which such limitation is to apply. After receiving such notice, the Customer shall, except as otherwise provided herein, reduce its use of power during the Curtailment Period to which the notice applied, to the level specified by the Authority. Each such notice shall be deemed received by the Customer if the Authority shall have issued or attempted to issue that notice.

(S) The Authority will use reasonable efforts to give as much advance notice as practicable of probable curtailments when circumstances permit. It is recognized that because of the Character of Service of this Schedule, Customer Notice by the Authority of a Demand Response Buy Back interruption or curtailment could be two (2) minutes or less and not more than ten (10) minutes prior to the expected initiation of the Curtailment Period.

(T) All power and energy used by the Customer during a Curtailment Period in excess of the demand limitation set forth in the Authority's notice for such Curtailment Period shall be classified as Excess Power and subject to penalties as set forth herein; provided, however, that the Authority shall be under no obligation whatsoever to furnish such Excess Power.

(U) Nominated demand for the Demand Response Buy Back service is not subject to the Authority's Demand Sales Adjustment Clause DSC-18, or its currently applicable successor clause, if any.

Section 3. Monthly Credits

For all Demand Response Buy Back service provided hereunder, the monthly credit for controlled load response during a Curtailment Period shall be based on a combination of the sum of Nominated Demand as specified by the Customer and the specified Monthly Credit ($/kW-month), and the sum of the Nominated Demand as specified by the Customer (regardless of the demand level requested by the Authority), the number of Curtailment Periods that have occurred within the billing period, and the specified Event Credit rate ($/Event per MW) as indicated below and, as follows:

(G) Monthly Credit

Nominated kW of Demand Response Buy Back Service………..……………..$(665.00)/MW

(H) Event Credit

For all service provided hereunder other than Excess Power, the Monthly Event Credit for Demand Response Buy Back Service shall be determined as follow:

1. Nominated MW of Demand Response Buy Back service .... _____ (MW)
2. Number of Curtailment Periods within billing period .... ______ (#)
3. Credit per Curtailment Period per MW .... $(333.00) ($/MW)
4. Total Credit (a * b * c) .... $____________

(I) Excess Power Charge

The price for Excess Power used by the Customer in each Curtailment Period shall be 200% of the Authority's reasonable best estimate of its incremental cost (including opportunity costs) of supplying such Excess Power and any penalties imposed on the Authority by the Regional and Sub-regional Reliability Councils and their Balancing Authority. Such incremental costs may include both demand-related and energy-related costs.

Section 4. Determination of Demands

The Customer's Demand Response Buy Back demand for each Delivery Point shall be established initially by mutual agreement of the Authority and the Customer, as evidenced in the Delivery Point Specification Sheet for the Delivery Point that is attached to, and part of, the Service Agreement between the Customer and the Authority. The sum of the Customer's Demand Response Buy Back for each Delivery Point will serve as the basis for the Nominated MW of Demand Response Buy Back included in the calculation of the Monthly Credit in Section 3 above.

Section 5. Control Characteristics

(K) Frequency

The Control Conditions will typically result in less than twenty (20) Curtailment Periods per calendar year and will not exceed twenty (20) Curtailment Periods per calendar year.

(L) Notice

Notice for immediate customer action by the Authority of a Demand Response Buy Back interruption or curtailment could be two (2) minutes or less and not more than ten (10) minutes.

(M) Duration

The duration of a single Demand Response Buy Back Curtailment Period will be one (1) hour or less. Under typical circumstances, the Curtailment Period will not exceed one (1) hour.

(N) Major Disturbance

In the event of a major disturbance, as defined by the Authority, greater frequency, less notice, or longer duration than listed above may occur. In the event of a major disturbance, the Customer is not entitled to additional compensation beyond that indentified herein, regardless of greater frequency, less notice or longer duration. The Customer agrees that the Authority will not be liable for any damages or injuries that may occur as a result of the implications of a major disturbance, including, but not limited to, greater frequency, less notice (including no notice) or longer duration.

(O) Customer Responsibility

7. Upon the successful installation of the monitoring and load control equipment, a test of this communications and monitoring equipment will be conducted by the Authority. Testing will be conducted at a mutually agreeable time and date between Authority and Customer.

8. The Customer shall be responsible for providing and maintaining the appropriate equipment required to interrupt or curtail the Customer's load within the required time as specified by the Authority and upon receiving notice from the Authority, as specified in the Service Agreement between the Customer and the Authority.

9. The Authority will direct the interruption or curtailment of a portion or all of the Customer's Nominated Demand Response Buy Back service for up to a one (1) hour period once per year for testing purposes at a mutually agreeable time and date, if the Customer's load has not been successfully controlled during a load control event in the previous twelve (12) months. Testing purposes include the testing of the load control equipment to ensure that the Customer's load is able to be monitored by the Authority within the agreed upon specifications.

Section 6. Term of Service

Service under this Schedule shall continue, subject to Limitation of Availability, until terminated by either the Authority or the Customer upon written notice given at least five (5) years prior to termination. The Authority may terminate service under this Schedule at any time for the Customer's failure to comply with the terms and conditions of this Schedule or the Service Agreement. Prior to any such termination, the Authority shall notify the Customer at least thirty (30) days in advance and describe the Customer's failure to comply. The Authority may then terminate service under this Schedule at the end of the 30-day notice period unless the Customer takes measures necessary to eliminate, to the Authority's satisfaction, the compliance deficiencies described by the Authority. Notwithstanding the foregoing, if, at any time during the 30-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Authority shall be entitled to suspend forthwith the monthly credits under this Schedule.

Section 7. Special Provisions

(O) Monitoring of the Customer's load shall be accomplished through the Authority's use of monitoring circuits connected directly to the Customer's switching equipment of the Customer's load and may be controlled by use of other means acceptable to the Authority.

(P) The Customer shall grant the Authority reasonable access for installing, maintaining, inspecting, testing and/or removing Customer-owned communications and monitoring load control equipment.

(Q) It shall be the responsibility of the Customer to determine that all of its electrical equipment to be controlled is in good repair and working condition. The Authority will not be responsible for the repair, maintenance, or replacement of the Customer's electrical equipment.

(R) The Authority will not be required to install load monitoring equipment if the installation cannot be economically justified.

(S) Credits under this Schedule will commence after the installation, inspection, and successful testing of the load monitoring equipment. Credits are applied to specific Curtailment Periods only, as requested by the Authority and responded to by the Customer.

(T) The Customer shall hold the Authority and its designated representatives harmless from any and all claims, actual or threatened, for economic or punitive damages including but not limited to life, safety, equipment, facilities product, inventory, and opportunity resulting from interruption or curtailment of electric service provided under this Schedule and the Service Agreement.

(U) Service under this Schedule is subject to the terms of the currently effective Schedule L and/or Schedule L - Interruptible, the currently effective General Terms and Conditions attached thereto, and the Service Agreement between the Customer and the Authority.

Pricing for DRBB provided herein is in effect until modified or withdrawn. This pricing is subject to an annual evaluation at which time it may be modified or withdrawn if circumstances warrant. This offer does not commit the Authority to future such offerings.

Adopted [date]

Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule L-17-DRB, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
EXPERIMENTAL
LARGE LIGHT AND POWER
ECONOMIC DEVELOPMENT SERVICE
RIDER L-18-ED

SECTION 1. Availability:

(A) Service hereunder, “Economic Development Service” (hereinafter, “Rider) is available to Customers meeting the availability requirements of the Authority's Large Light and Power Rate Schedule L-18 or its successor (hereinafter, “Schedule L"), to which this Rider is attached and made a part of. In addition, service hereunder shall be available only to New Load.

(B) New Load, as used herein, is load that was not served by the Authority prior to the initial effective date of this Rider, and has been determined by the Authority as economic development of the Authority’s service area in accordance with Section 1 (C), below. For existing Customers, New Load is the net incremental load (a) above that which existed and (b) was not served by the Authority under Schedule L or under riders L-18-I, L-18-EP, L-18-EP-O, and L-18-SB, or their successors, prior to the initial effective date of this Rider or, by load served directly from power and energy requirements purchased by a Wholesale Customer from the Authority. Wholesale Customers as used herein shall mean a municipal corporation, electric cooperative, or joint municipal power agency organized under the laws of the State of South Carolina that is a long-term, firm wholesale customer of the Authority. As used herein, New Load does not include: replacement electrical machines, equipment or processes; load shifted from one Delivery Point on the Authority’s system to another on the Authority’s system; load that existed and was served by another electric provider prior to that load being served by the Authority. All qualifying New Load for either a new or existing customer shall not exceed 40 MWs per customer per delivery point. Furthermore, the aggregate amount of New Load available to all Authority customers shall not exceed 300 MWs.

(C) Contribution of New Load to Economic Development: In order to receive service for this Rider, the "Customer" shall have:

v. Requirements for service hereunder of at least 1,000 kW of load under this Rider (hereinafter “Firm-ED Load”), **and**;

vi. Must employ an additional workforce within the Authority’s service area of a minimum of thirty-five (35) full time equivalent (FTE) employees per 1,000 kW demand of Firm-ED Load during the Contract Period, **or**, must result in a minimum capital investment within the Authority’s service area of $500,000 per 1,000 kW demand of Firm-ED Load.

(D) Service hereunder shall be available only to specified Delivery Points upon a prior written agreement between the Authority and the Customer with respect to each such Delivery Point, in the form of an appropriate Delivery Point Specification Sheet attached to the Service Agreement between the Customer and the Authority.

(E) This Rider is not available for renewal of service for a period of time following interruptions such as equipment failure, temporary plant shutdown, strike, or cessation of operations due to economic conditions. This period of time is the longer of either one year or the Notification Period as defined in individual customer contracts. However, if change of ownership occurs after the customer contracts for service under this Rider, the successor customer may be allowed to fulfill the balance of the contract under this Rider and continue to receive the discount as outlined in this Rider, subject to the eligibility requirements and other provisions hereof.

(F) This Rider is applicable and available to new applicants through December 31, 2014. Additionally, service hereunder is made available by the Authority on an experimental, pilot-program basis. Accordingly, the availability of such service, the terms and conditions thereof, and the operational aspects of such service are subject to termination or change, in whole or in part; provided, however, that this Rider will remain in effect for any Customer who has been approved to receive service.

SECTION 2. Character of Service:

Electric power and energy delivered shall be of the same character as that described in Section 2 of Schedule L, which is incorporated herein by reference.

SECTION 3. Monthly Billing Rates:

The charges for service hereunder shall consist of the following:

(A) Demand Charge:

The monthly Demand Charge per Firm-ED kW shall be determined as follows:

Demand Charge per Firm-ED kW = Schedule L Base Demand Charge – ED Discount

Where the ED Discount is determined by taking a percentage of the base demand charge as stated in the then-current Schedule L, whereas, the ED Discount is set forth in the following table:

Months 1 – 12	**45% of Schedule L Base Demand Charge**
Months 13 – 24	**30% of Schedule L Base Demand Charge**
Months 25 – 36	**20% of Schedule L Base Demand Charge**
Months 37 – 48	**10% of Schedule L Base Demand Charge**
After Month 48	**No Discount**

(B) Energy Charge:

Same as the Energy Charge per kilowatt-hour and Fuel Adjustment Charge in Rate Schedule L.

(C) All other monthly charges per Schedule L will apply.

SECTION 4. General Provisions:

Customer must make an application to the Authority for service of New Load under this Rider and Authority must approve such application before Customer may receive service hereunder. The application must include a description of the amount of and nature of the new or additional load and the basis on which the Customer qualifies as set forth in Section (1) above. In the application, Customer must affirm that availability of this Rider was a factor in Customer's decision to locate the New Load on Authority's system. The application shall also specify the total number of full time equivalent employees (FTE) employed by Customer in all establishments receiving electric service from Authority's system, at the time of application for this Rider, as well as the additional FTE attributed to the New Load. Alternatively, Customer must include a description of the minimum capital investment requirement,

including verification of the value of the declared capital investment. The Authority reserves the right to verify at any time during the Contract Period (as defined in Section 5) that the Customer satisfies the availability and eligibility requirements set forth in Section 1 hereof. Customer shall provide a statement to the Authority, verified by an officer of the Customer or their designee, that the Customer satisfies the availability and eligibility requirements of the Rider. This statement will be required annually during the Contract Period from the operational date of the new or expanded facility. The operational date of the new or expanded facility that results in New Load shall be no more than one year from date of application.

SECTION 5. Contract Period:

Each Customer shall enter into a Service Agreement to purchase electricity from the Authority for a minimum initial term of 8 years from the date the new or expanded facility is fully operational as declared by the Customer, herein defined as the Contract Period. Thereafter, either party can terminate the Service Agreement at the end of the initial Contract Period as provided in the terms and conditions of the then-applicable Schedule L. Service Agreement will include specified Contract Demand for Firm-ED Load which meets the requirements as stated in Section 1 of this Rider. An individual establishment and/or physical location will not be allowed to receive ED Discounts for more than four (4) years under this Rider, unless the Authority, at its sole discretion, agrees to accept and approve a new application and contract for qualifying New Load.

Discounts under this Rider shall begin no earlier than the operational date of the new or expanded facility and shall end 48 months after the later of (i) operational date of the facility, provided that such operational date shall be no more than one year after the application date, or, (ii) the date the Customer's first bill is rendered under this Rider.

If at any time during the term of contract under this Rider, Customer violates any of the terms and conditions of the Rider or the Service Agreement, Authority may discontinue service under this Rider without notice and bill Customer under the applicable schedule without further ED Discounts. In the event electric service is terminated or discontinued under this Rider by the Customer or the Authority, or the Contract Demand for Firm–ED is reduced by Customer before the end of the Contract Period, Customer shall pay Authority, in addition to all other applicable charges, the sum of all ED Discounts received, plus interest compounded annually, for the Firm-ED Load that will no longer be served by Authority. The rate of interest shall be the rate per annum which will be based on the then current LIBOR index. The Authority shall have the right to adjust the total payment required by the Customer, as previously described, at its sole discretion.

SECTION 6. Other Terms and Conditions:

Except as otherwise provided in this Rider, service hereunder shall be subject to all terms and conditions of the then-applicable Large Light and Power Rate Schedule L.

The Delivery Date is the first date service is supplied under the contract.

A customer may have a portion of the customer's electrical energy supplied by customer-owned generation provided the customer is in compliance with Santee Cooper's then-current Standard for Interconnecting Customer-Owned Generation.

Adopted ____________, 2015
Effective for bills rendered on and after April 1, 2018.

Supersedes:
Schedule L-17-ED, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
ECONOMIC DEVELOMENT SALES ADJUSTMENT CLAUSE
(EDA-18)

Section 1. Purpose:

The Economic Development Rates (Riders L-13-ED-02 & L-14-ED-T) were approved by the Authority's Board of Directors on April 26, 2013 and April 25, 2014, respectively. The Economic Development Rate is available to customers who qualify that are directly served by the Authority as well as Wholesale Customers indirectly served by rider. Wholesale customers as used herein shall mean a municipal corporation, electric cooperative, or joint municipal power agency organized under the laws of the State of South Carolina that is a long-term, firm wholesale customer of the Authority. The purpose of this clause is to credit the Authority's firm-requirements and interruptible service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority from the direct and indirect sales associated with Economic Development Service Riders L-13-ED-02 & L-14-ED-T or their successors, or, associated Rider as provided in memorandum of understanding and agreement between the Authority and its customers, to the extent that such sales may not be reflected in the currently effective rates for such firm-requirements and interruptible service customers.

Section 2. Applicability:

The Economic Development Sales Adjustment Clause is applicable, to and becomes a part of, all of the Authority's published rate schedules that so specify.

Section 3. Adjustment of Bills:

Each customer's current monthly bill, as computed under the appropriate rate schedule, will be decreased by an amount equal to the result of multiplying (i) the appropriate rate "D" (as defined below), times (ii) either (a) in the case of each Large Light & Power ("Industrial") customer, that customer's current Firm Billing Demand and Interruptible Billing Demand, excluding L-13-ED-02 & L-14-ED-T Rate customers' load, or portions of load thereof, or (b) in the case of each Municipal Light & Power ("Municipal") customer, that customer's current Billing Demand, or (c) in the case of each other type of customer ("Distribution Service" customers), the total billed kWh of energy for the period to which the bill applies. Rate Riders L-13-ED-02 & L-14-ED-T Service customers, or portions of service thereof, are excluded from the Economic Development Sales Adjustment Clause during the period of the discount as defined in L-13-ED-02 & L-14-ED-T and specific to each customer's load or portion of customer's load thereof.

The rate D shall, for each respective customer class, be determined as follows:

$$D = R_D / B_D$$

Where:

D = The adjustment rate factor, in dollars per kW for Industrial and Municipal customers and in dollars per kWh for Distribution Service customers, in each case, rounded to the nearest one-thousandth of a cent.

R_D = The total demand-related or capacity-related revenues associated with Economic Development Riders L-13-ED-02 & L-14-ED-T for the preceding month allocated to the customer class (Industrial [as modified above], Municipal, or Distribution Service), based on the projected average four-month class coincident peak demand contributions for the current calendar year, as set forth in the Authority's then most recently adopted load forecast.

B_D = The projected total billing units for the customer class to which the adjustment rate factor, D, is to apply, for the current month, in kW for Industrial (as modified above) and Municipal customer classes and in kWh for Distribution Service customer classes.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule EDA-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
FUEL ADJUSTMENT CLAUSE
FAC-18

Applicability:

This Fuel Adjustment Clause is applicable to and becomes a part of each of the Authority's published Rate Schedules and rate riders thereto that so specify.

Adjustment of Bills:

Each monthly bill, computed under the appropriate Rate Schedule and appropriate rate riders, will be increased or decreased by an amount equal to the result of multiplying the measured or used kWh by the factor F, determined as follows:

$$F = (F_m/S_m - F_b/S_b) \times (1 / 1\text{-}K)$$

Where:

1. F = Adjustment factor in dollars per kWh rounded to the nearest one-thousandth of a cent.

2. F_m = Total fuel and purchased power cost for the three preceding months, consisting of the costs of:

   a. the cost of fossil, nuclear and renewable fuel consumed, including the net cost of allowances expensed concurrent with regulated emissions, in the Authority's own plants and the Authority's share of fossil, nuclear and renewable fuel consumed in jointly owned or leased plants, plus

   b. the actual identifiable fossil, nuclear and renewable fuel costs associated with energy purchased for reasons other than identified in (c) below, plus

   c. the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Authority to substitute for its own higher cost energy, less

.
   d. the cost of fossil, nuclear and renewable fuel recovered through inter-system sales and any applicable non-firm intra-system sales (such as Economy Power, Secondary Power), including the fuel costs recovered through economy energy sales and other energy sold on an economic dispatch basis.

3. S_m = kWh sales which shall be equated for the three preceding months to the sum of (i) generation, (ii) purchases, (iii) interchange in, less (iv) energy associated with pumped storage operations, less (v) sales referred to in F_m (d) above, less (vi) average annual power supply transmission losses in decimal form times the net sum of (i), (ii), (iii), (iv), and (v) in this definition of S_m.

4. F_b/S_b = \$0.03641

Where:

a. F_b = Total estimated fuel cost in the base period.

b. S_b = Total estimated kWh sales for the base period.

5. K = Allowance for capital improvements and distribution losses, as set forth in each Rate Schedule and applicable rate riders to which this Clause applies.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule FAC-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
DEMAND SALES ADJUSTMENT CLAUSE
(DSC-18)

Section 1. Purpose:

The purpose of this Clause is to credit the Authority's firm-requirements and Interruptible Service customers with appropriate shares of the demand-related or capacity-related revenues, if any, obtained by the Authority through Non-Class Sales, to the extent that such sales may not be reflected in the currently effective rates for such firm-requirements customers. Such demand-related and capacity-related revenues shall mean charges recovered on a kilowatt (kW) or reservation basis as well as charges recovered through a kilowatt-hour (kWh) basis from Section c of rider L-18-EP-AU. As used herein, "Non-Class Sales" consist of (i) off-system, inter-utility sales, and (ii) non-firm, non-requirements, on-system sales (such as sales of Interruptible Power and Standby Power pursuant to the Authority's Large Light & Power Rate Schedule and the currently effective riders thereto).

Section 2. Applicability:

The Demand Sales Adjustment Clause is applicable, to and becomes a part of, all of the Authority's published rate schedules that so specify.

Section 3. Adjustment of Bills:

Each customer's current monthly bill, as computed under the appropriate rate schedule, will be decreased (or, when applicable, increased) by an amount equal to the result of multiplying (i) the appropriate rate "D" (as defined below), times (ii) either (a) in the case of each Large Light & Power ("Industrial") customer, that customer's current Firm Billing Demand, or (b) in the case of each Municipal Light & Power ("Municipal") customer, that customer's current Billing Demand, or (c) in the case of each other type of customer ("Distribution Service" customers), the total billed kWh of energy for the period to which the bill applies. For Interruptible Service customers, Non-Class Sales are exclusive of non-firm sales specific to Interruptible Power.

The rate D shall, for each respective customer class, be determined as follows:

$$D = (R_m - R_b) / B_m$$

Where:

D = The adjustment rate factor, in dollars per kW for Industrial and Municipal customers and in dollars per kWh for Distribution Service customers, in each case, rounded to the nearest one-thousandth of a cent.

R_m = The total revenues from Non-Class Sales for the preceding month allocated to the customer class (Industrial, Municipal, or Distribution Service), based on the projected average four-month class coincident peak demand contributions for the current calendar year, as set forth in the Authority's then most recently adopted load forecast. For Interruptible Service customers, Non-Class Sales exclude non-firm sales specific to Interruptible Power.

R_b = The allocated revenues from Non-Class Sales, reflected in the currently effective rate(s) for the customer, which shall, for purposes of this Clause, be the following amounts:

i. For Firm Industrial customers: $62,000 per month beginning April 1, 2018.

j. For Interruptible Industrial customers: $120,000 per month beginning April 1, 2018.

k. For Municipal customers: $12,000 per month beginning April 1, 2018.

l. For Distribution Service customers: $303,000 per month beginning April 1, 2018.

B_m = The projected total billing units for the customer class to which the adjustment rate factor, D, is to apply, for the current month, in kW for Industrial and Municipal customer classes and in kWh for Distribution Service customer classes.

Adopted __________, 2015
Effective for service rendered on and after April 1, 2018

Supersedes:
Schedule DSC-17, Effective April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
POLE ATTACHMENT
SCHEDULE PA-18

Section 1. Availability:

This Schedule is available in the retail service area of the Authority in Berkeley, Georgetown, and Horry Counties, South Carolina.

Section 2. Applicability:

This Schedule is applicable to all telephone companies, cable television and other such communication companies for the purpose of attaching their lines, cables, wireless or other non-linear devices to the Authority's distribution poles. When a telephone company and a cable company are affiliated, they shall nevertheless be treated as separate entities and will be billed separately for each attachment.

Section 3. Rates and Charges:

(I) Annual Pole Attachment Billing Rate

1. The annual charge for service hereunder shall be $14.60 for each attachment for each year (or portion of a year).

(J) Monthly Energy Charge

1. Customers shall be responsible for any electrical energy consumption in kilowatt-hours of its attachments and/or associated communication equipment, based on the full power ratings of said devices/equipment.

2. Energy Charge:
   a) Base Energy Charge:
      All kWh ……………………………………………………………………$0.1018/kWh

(K) Fuel Adjustment Clauses

For each kWh, the charge per kWh determined for the month pursuant to the Authority's Fuel Adjustment Clause FAC-18, or its currently applicable successor clause, if any, with "F_b/S_b" and "K" of the formula in said clause being equal to $0.03641/kWh and .085, respectively.

(L) Taxes

Amounts for "payments in lieu of taxes," as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above annual rate. The charges computed at the above rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fees, assessments, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax Commission or its successor.

Section 4. Payment:

Joint attachment bills will be rendered annually on a net basis. Energy bills (when applicable) will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within fifteen (15) days after the date in which the bill is mailed or otherwise rendered. If the amount is not received by said due date, the amount of the bill will be increased by the greater of fifty cents ($0.50) or two percent (2%) of the amount then outstanding, including late payment charges.

Section 5. Terms and Conditions:

(E) Linear Pole Attachment:

In order to receive service hereunder, the Customer shall be required to enter into a contract with the Authority in the form Attachment A hereto (Linear Pole Attachment Service Agreement), which shall govern the provision of such service by the Authority and the use of such service by the Customer.

(F) Non-Linear Pole Attachment:

In order to receive service hereunder, the Customer shall be required to enter into a contract with the Authority in the form Attachment B hereto (Non-Linear Pole Attachment Service Agreement), which shall govern the provision of such service by the Authority and the use of such service by the Customer.

Adopted _______________, 2015
Effective for bills rendered on and after April 1, 2018.

Supersedes: Schedule PA-17, April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
Service Agreement
For
Linear Pole Attachment Service

This Agreement made and entered this ______ day of _____________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and ________, hereinafter referred to as the "Customer".

1. The parties hereby terminate any and all prior agreements providing for the attachment of the Customer's communication facilities to the Authority's poles.

2. Whenever during the term of this agreement the Customer wishes to install any of its wires or appurtenances upon any poles of the Authority, the Customer shall give written notice of such intention to the Authority, identifying the poles and describing the facilities it wishes to install thereon. As soon as reasonably possible after receipt of such notice the Authority shall, in writing, either consent to such installation or refuse such consent, but such consent shall not be unreasonably withheld.

3. If the Authority consents to such use, the Customer shall have the right to install and maintain its facilities on said poles at the locations and in the manner specified by the Authority, in accordance with the terms and provisions herein contained, and shall pay the annual charge contained in the Authority's Pole Attachment Schedule PA-18 or successor schedules.

4. The Customer shall provide the Authority prompt written notice of the removal of any wires and appurtenances from the Authority's poles, identifying the poles and describing the facilities removed.

5. (A) All installation, attachments, operations and maintenance of the Customer's facilities shall comply with all federal, state and local regulations, including, but not limiting the generality of the foregoing, the requirements set forth in the American National Standards, ANSI C2-2012 entitled "National Electric Safety Code" or such successor publication.

   (B) In addition to paragraph (A), all employees, agents or contractors of the Customer shall comply with the following requirements:

   1. Such employees, agents or contractors shall not approach nearer than five (5) feet to any energized electric circuit.
   2. Electrical hard hats shall be worn by all workers.
   3. All ladders must have safety straps.
   4. All employees, agents or contractors shall be properly secured while working from ladders or buckets.
   5. All employees, agents or contractors shall be sufficiently trained by the Customer to identify electric supply circuits in order to maintain required clearances, and the Customer shall, upon request, provide the Authority a certified copy of its safety training program.

6. (A) On the first day of January of each year of the term of this agreement, the Customer shall pay to the Authority the annual charge contained in the Authority's Pole Attachment Schedule PA-18 or successor schedules for each attachment used in any way by the Customer during the preceding calendar year, or any portion thereof.

   (B) The annual charge may be changed by the Authority from time to time and when so changed shall become effective at the time designated by the Authority and the annual charge for each calendar year in which there is such a change shall be prorated.

7. All of the Customer's facilities and property shall be installed, removed and maintained at the sole cost,

risk and expense of the Customer. The Customer shall, at any time, at its own cost, risk and expense, upon written notice from the Authority, change, alter, improve, or renew it installations and facilities covered hereby in such manner as the Authority may direct.

Should it become necessary at any time to change the location of any of the Customer's wires, cables, or other facilities from one position to another, such work may be done by the Authority at the sole cost, risk and expense of the Customer. The Customer shall not at any time make any changes in the location of its attachments to, or in the use of, the Authority's poles or facilities, without the written consent of the Authority.

8. (A) The Customer agrees to indemnify and hold the Authority harmless from the consequences of any property loss or damage, death or personal injury whatever, accruing or suffered or sustained from or by reason of an act, neglect or default of the Customer, its agents, servants or employees, in or about or in connection with the exercise of such attachment rights, or which may, in any manner or to any extent be attributable thereto, or to the presence of any property of the Customer upon the Authority's poles and whether or not acts, neglect or defaults on the part of the Authority, it agents, servants, or employees may have contributed to such loss, injury or damage, except that the Customer shall not be held responsible under this Agreement, for any loss of life, or personal injury or property damage accruing solely from the Authority's, its agents', servants', or employees' own negligence, without fault of the Customer, its agents, servants or employees.

   (B) Prior to the taking of any action with respect to any claim for loss or damage sustained as a result of the joint use of poles with claim for loss or damage is covered by the provisions of this Agreement, the Authority or the Customer, as the case may be, shall immediately upon being notified of the existence of such claim, notify the other party in writing of such claim and all particulars with respect thereto. In cases in which liability for such claim would, if proven, require the Customer to indemnify the Authority under this Agreement, the Authority shall make no settlement or disposition of such claim without written approval of the Customer. Should the Customer and the Authority disagree concerning the liability for any particular claim for which the Customer would have to indemnify the Authority under this Agreement, the Customer may defend against such claim in any action at law or equity, the cost of such defense litigation to be borne solely by the Customer. The Customer's obligation to indemnify the Authority shall not arise until after final disposition by lawful authority of the liability for any claim so defended against. The Authority agrees to cooperate fully with the Customer in the defense of any such claims. Where both the Authority and the Customer dispute any claim for loss or damage arising from the joint use of poles, the Customer and the Authority agree to jointly defend against any claim for loss or damage sustained as a result of the joint use of poles, the cost of such litigation, if successful, to be borne equally by the parties.

9. The Authority makes no warranty as to its title or rights to any of the property herein referred to and only grants the rights to set out in this instrument insofar as the Authority's rights and titles extend. Nothing herein contained shall be construed as a representation or guarantee by the Authority to the Customer of permission from municipal or other public authorities or property owners for the exercise of any of the rights herein described or referred to. The Customer shall not assign, transfer, sublet or otherwise alienate any of the rights or privileges herein granted without the written approval of the Authority.

10. Either party may terminate this Agreement at any time by giving ninety (90) days advance written notice of such intention to the other party.

11. In addition to the right of termination contained in Section 10 hereof, the Authority in its discretion may at any time or times immediately terminate the use by the Customer on any or all attachments covered by this Agreement for any of the following causes:

    (1) Installation, maintenance, or operation of facilities by the Customer at locations or positions on the Authority's poles other than those specified by the Authority or in a manner different from that so specified.

(2) Installation, maintenance, or operation of facilities by the Customer, in any way impairing, endangering or otherwise adversely affecting the system of the Authority.

(3) Objection or prohibition by municipal or any other public authorities, or by property owners, of or to any use of the Customer of the rights herein granted.

(4) The failure of the Customer to comply with any of the terms or provision of this Agreement.

Upon written notice by the Authority to the Customer that any of the above listed causes has arisen, the Customer shall forthwith remove, at its own expense, all of its facilities from any pole or poles as may be directed in said notice.

12. In the event that the Authority relocates its lines or poles, on which attachments of the Customer are located, it shall give prior notice of such intention to the Customer and, at the Customer's sole expense, the Customer may reattach its facilities to the relocated poles under the same conditions in their original locations.

If the Authority wishes to remove any pole or poles because of discontinuance of use by it of all or part of a line or lines, it shall have the right to do so notwithstanding the use thereof by the Customer. Where any such pole or poles are being used by the Customer, advance notice of the removal thereof shall be given to the Customer and the Customer shall remove its attachments from said pole or poles at its own expense and make any provisions necessary for the operation of its lines in such locations without any responsibility therefore by the Authority.

In either event, should the Customer fail to remove its attachments within the ninety (90) days after notification, the Authority shall have the right to remove or cause to be removed such attachments at the Customer's expense.

13. In cases where sufficient pole space for the Customer's attachment is not available on the Authority's poles, the Customer will pay the Authority all costs for installing a new pole of sufficient height less the salvage value of the pole replaced but including the cost of removal of the replaced pole.

14. In the event of any termination of the Agreement by either party under the terms of Section 10 hereof, or any termination by the Authority of the use of any pole or poles in accordance with Section 11 hereof, or the relocation or removal of lines or poles under Section 12 hereof, if the Customer fails to remove its facilities from any or all of the Authority's poles or systems covered by this Agreement, the Authority shall have the right to remove or cause to be removed the same, and the Customer shall pay to the Authority all costs and expenses of any such removal.

15. It is specifically understood by Customer that restoration of service which has been disrupted by any reason whatsoever shall be restored at the Authority’s lowest priority level. Where multiple parties are involved in emergency restorations, access to the Authority’s poles will be controlled by the Authority.

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed and their corporate seals to be hereunto affixed by their proper officers thereunto duly authorized as of the date hereinabove mentioned.

ATTEST: **SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**

BY: ______________________________ **BY:** ______________________________

ATTEST: **(CUSTOMER)**

BY: ______________________________ **BY:** ______________________________

Adopted _________________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes: Attachment A, April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
Service Agreement
For
Non-Linear Pole Attachment Service

This Agreement made and entered this ______ day of _____________, 20__, by and between the South Carolina Public Service Authority, hereinafter referred to as "the Authority", and __________________________, hereinafter referred to as the "Customer".

3. Prior to installing any facilities, Customer shall submit written notice of intent to install to the Authority, identifying the poles and describing the facilities it wishes to install thereon. Upon review of the written notice of the intent to install, the Authority shall either accept or decline the proposal, and provide Customer with written notice of its decision, which shall constitute the initial installation of facilities ("Initial Installation"). Whenever during the term of this agreement Customer wishes to install additional facilities upon any poles of the Authority, Customer shall give written notice of such intention to the Authority, identifying the poles and describing the facilities it wishes to install thereon. As soon as reasonably possible after receipt of such notice the Authority shall, in writing, either consent or refuse such request. The Authority retains the right to limit the number of facilities installed pursuant to this agreement.

2. If the Authority consents to such use, Customer shall have the right to install and maintain its facilities on said poles at the locations and in the manner specified by the Authority, in accordance with the terms and provisions herein contained, and shall pay the annual charge recited herein. The Authority reserves the right to specify any devices, adapters, circuit breakers, fuses, conductors, and so forth used to derive a source of power from its facilities. An installation drawing for the power supply configuration may be prescribed by the Authority as it deems necessary.

3. Customer shall provide the Authority prompt written notice of the removal of any facilities from the Authority's poles, identifying the poles and describing the facilities removed.

4. All installation, attachments, operations and maintenance of Customer's facilities shall comply with all federal, state and local regulations, including, but not limiting the generality of the foregoing, the requirements set forth in the American National Standards, ANSI C2-2012, entitled "National Electric Safety Code" or such successor publication. All employees, agents or contractors of Customer shall comply with the following requirements:

   15. Such employees, agents or contractors shall not approach nearer than five (5) feet to any energized electric circuit.

   16. Electrical hard hats shall be worn by all employees, agents or contractors.

   17. All ladders must have safety straps.

   18. All employees, agents or contractors shall be properly secured while working from ladders or buckets.

   19. All employees, agents or contractors shall be sufficiently trained by Customer to identify electric supply circuits in order to maintain required clearances, and

Customer shall, upon request, provide the Authority a certified copy of its safety training program.

20. All equipment shall have a company logo affixed allowing utilities and others to readily identify Customer as the owner.

21. Any cords, cables, and conduits shall be securely strapped in a workmanlike manner.

5. On the first day of January of each year of the term of this agreement, Customer shall pay to the Authority the annual charge contained in the Authority's Pole Attachment Schedule PA-18 or successor schedules for each attachment used in any way by Customer during the preceding calendar year, or any portion thereof. In addition to the annual charge, Customer shall be responsible for the electrical energy consumption in kilowatt-hours of its devices and/or associated communication equipment, based on the full power ratings of said devices/equipment, and shall be billed in accordance with the annual charge contained in the Authority's Pole Attachment Schedule PA-18 or successor schedules

6. All of Customer's facilities and property shall be installed, removed and maintained at the sole cost, risk and expense of Customer. These costs shall include any and all assistance provided by the Authority for the installation of said facilities. Customer shall, at any time, at its own cost, risk and expense, upon written notice from the Authority, change, alter, improve, or renew its installations and facilities covered hereby in such manner as the Authority may direct. Customer shall not at any time make any changes in the location of its attachments to, or in the use of, the Authority's poles or facilities, without the written consent of the Authority.

   The Authority will not undertake the relocation or transfer of Customer's facilities on an Authority Pole, except in the event of emergency repair situations where the Authority's Pole or Customer's facilities are damaged. In such cases, Authority will reserve the right to transfer Customer's facilities that are still attached to the Authority's Pole, remove the damaged pole, leave the repair/replacement work for Customer, and bill Customer the actual costs incurred to perform the Attachment and/or Facility transfer of Customer's facilities.

7. Customer agrees to indemnify and hold the Authority harmless from the consequences of any property loss or damage, death or personal injury whatsoever, accruing or suffered or sustained from or by reason of an act, neglect or default of Customer, its agents, contractors, servants or employees, in or about in connection with the exercise of such attachment rights, or which may, in any manner or to any extent be attributable thereto, or to the presence of any property of Customer upon the Authority's poles and whether or not acts, neglect or defaults on the part of the Authority, its agents, servants, or employees may have contributed to such loss, injury or damage, except that Customer shall not be held responsible under this Agreement for any loss of life, or personal injury or property damage accruing solely from the Authority's, its agents', servants', or employees' own negligence, without fault of Customer, its agents, servants or employees.

   Prior to the taking of any action with respect to any claim for loss or damage sustained as a result of the joint use of poles with claim for loss or damage is covered by the provisions of this Agreement, the Authority or Customer, as the case may be, shall immediately upon being notified of the existence of such claim, notify the other party in writing of such claim and all particulars with respect thereto. In cases in which liability for such claim would, if proven, require Customer to indemnify the Authority under this Agreement, the Authority shall make no settlement or disposition of such claim without written approval of Customer. Should Customer and the Authority disagree concerning the liability for any particular claim for which Customer would have to indemnify the Authority under this Agreement, Customer shall defend against such claim in any action at law or equity, the cost of such defense litigation to be borne solely by Customer. The Authority agrees to cooperate fully with Customer in the defense of any such claims. Where both the Authority and Customer dispute any claim for loss or damage arising from the joint use of poles, Customer and the Authority agree to jointly defend against any claim for loss or damage sustained as a result of the joint use of poles, the cost of such litigation, if successful, to be borne equally by the parties.

8. Nothing herein contained shall be construed as a representation or guarantee by the Authority to Customer of permission from municipal or other public authorities or property owners for the exercise of any of the rights herein described or referenced. Customer agrees to obtain at its sole expense, all permits, approvals, licenses, conveyances, reliances, easements and authorizations from any and all State, Federal and Local Governmental agencies, and from any and all third parties, which may be necessary or desirable for the installation and maintenance of Customer's facilities. Customer shall not assign, transfer, sublet or otherwise alienate any of the rights or privileges herein granted without the written approval of the Authority.

9. Either party may terminate this Agreement at any time by giving ninety (90) days advance written notice of such intention to the other party. Upon termination, Customer shall pay to the Authority all amounts due and owing under this agreement, including but limited to any unpaid or unbilled annual charges.

10. In addition to the right of termination contained in Section 9 hereof, the Authority in its discretion may at any time or times immediately terminate the use by Customer on any or all attachments covered by this Agreement for any of the following causes:

i. Installation, maintenance, or operation of facilities by Customer at locations or positions on the Authority's poles other than those specified by the Authority or in a manner different from that so specified.

ii. Installation, maintenance, or operation of facilities by Customer, in any way impairing, endangering or otherwise adversely affecting the system of the Authority.

iii. Objection or prohibition by municipal or any other public authorities, or by property owners, of or to any use of Customer of the rights herein granted.

iv. The failure of Customer to comply with any of the terms or provision of this Agreement.

Upon written notice by the Authority to Customer that any of the above listed causes has arisen, Customer shall forthwith remove, at its own expense, all of its facilities from any pole or poles as may be directed in said notice.

11. In the event that the Authority relocates its lines or poles, on which attachments of Customer are located, it shall give prior notice of such intention to Customer and, at Customer's sole expense, Customer may reattach its facilities to the relocated poles under the same conditions in their original locations.

If the Authority wishes to remove any pole or poles because of discontinuance of use by it of all or part of a line or lines, it shall have the right to do so notwithstanding the use thereof by Customer. Where any such pole or poles are being used by Customer, advance notice of the removal thereof shall be given to Customer. Customer shall have the right to purchase the pole or poles at the higher of the pole's (1) then-value, in-place cost, or (2) net salvage value. Customer will indemnify and save harmless the Authority from any obligation, liability, cost, or charge incurred for the pole after the transfer of title of the pole to Customer. If Customer does not purchase the pole or poles, Customer shall remove its attachments from said pole or poles at its own expense and make any provisions necessary for the operation of its lines in such locations without any responsibility therefore by the Authority.

In either event, should Customer fail to remove its attachments within ninety (90) days after notification, the Authority shall have the right to remove or cause to be removed such attachments at Customer's expense.

12. In cases where sufficient pole space for Customer's attachment is not available on the Authority's poles, Customer will pay the Authority all costs for installing a new pole of sufficient height less the salvage value of the pole replaced but including the cost of removal of the replaced pole.

13. In the event of any termination of the Agreement by either party under the terms of Section 9 hereof, or any termination by the Authority of the use of any pole or poles in accordance with Section 10 hereof, or the relocation or removal of lines or poles under Section 11 hereof, if Customer fails to remove its facilities from any or all of the Authority's poles or systems covered by this Agreement, the Authority shall have the right to remove or cause to be removed the same, and Customer shall pay to the Authority all costs and expenses of any such removal.

14. It is specifically understood by Customer that restoration of service which has been disrupted by any reason whatsoever shall be restored at the Authority's lowest priority level. Where multiple parties are involved in emergency restorations, access to the Authority's poles will be controlled by the Authority**.**

IN WITNESS WHEREOF, the parties hereto have caused these presents to be executed and their corporate seals to be hereunto affixed by their proper officers thereunto duly authorized as of the date hereinabove mentioned.

ATTEST: **SOUTH CAROLINA PUBLIC SERVICE AUTHORITY**

BY: ______________________________ **BY:** ______________________________

ATTEST: **(CUSTOMER)**

BY: ______________________________ **BY:** ______________________________

Adopted ______________________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes: Attachment B, April 1, 2017

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY
(SANTEE COOPER)
DISTRIBUTED GENERATION RIDER (RETAIL)
RIDER DG-18

Section 1. Availability:

(A) Service hereunder is available on a first-come, first-served basis to residential and non-residential Customers receiving concurrent retail electric service from the Authority who independently install and operate a distributed generation system to supply a portion of their energy requirements. The total installed capacity of all leased and owned distributed generation facilities shall not exceed two percent of the previous five-year average of the residential and commercial customer class contribution to coincident retail peak demand, after which service under this Rider will no longer be available to new customers. Service hereunder shall be available only upon the approval of the Authority.

Section 2. Applicability:

(A) This Rider is applicable to all residential and non-residential customers in the retail service area of the Authority and shall be limited to Customers receiving concurrent service from the Authority where a photovoltaic or other qualifying generation source of energy as determined by the Authority is installed on the Customer's side of the delivery point, hereinafter the "Customer-Generator", for the Customer's own use, interconnected with and operated in parallel with the Authority's distribution system. Upon a Customer's installation of a qualifying generation source of energy other than a photovoltaic system, the Authority reserves the right to adjust the effective Standby Charge as listed in Section 4(A)(2) as appropriate.

(B) This Rider is only applicable for installed single-phased generation systems that comply with the Authority's then current Standard for Interconnecting Customer-Owned Small Generation hereinafter the "Interconnection Standard", which may be modified by the Authority as deemed necessary. The Nameplate Rating of the Customer's installed generation system and equipment must not exceed the lesser of 20 kW if a residential customer, 1,000 kW if non-residential customer, or the estimated maximum monthly kilowatt (KW) demand. The Customer must comply with the liability insurance requirements of the Interconnection Standard and submit an application to interconnect which must be accepted by the Authority. The Customer agrees to pay an application fee in accordance with the Interconnection Standard and any costs associated with upgrades required to maintain a safe and reliable distribution system.

Section 3. Character of Service:

(A) On an hourly basis, the Authority shall measure the energy delivered to the Customer by the Authority and the energy generated by the Customer-Generator and delivered to the Authority. In each hour, the measured energy generated by the Customer-Generator and delivered to the Authority will be subtracted from measured energy delivered to the customer by the Authority. This calculation will determine the customer's net energy usage. In hours in which the customer's net energy usage is less than zero, the resulting value will be multiplied by the effective Energy Credit as stated in Section 4(A)(3); and in hours in which the Customer's net energy usage is greater than zero, the resulting value will be multiplied by the effective Energy Charge as stated in Section 4(A)(4). To produce a monthly bill, all hourly credits and charges will be summed, and added to other metering, demand, standby charges, and/or applicable taxes and other charges as set forth in the applicable rate schedule or as identified herein. Such a combination of charges and credits may not result in a monthly bill below the monthly Minimum Charge as set forth in Section 4 (C) herein below. Charges or credits will be determined using the appropriate seasonal energy charges and other charges as set forth in Section 4 (A) herein below. If after the Customer's payment of the monthly Minimum Charge a Customer's bill for the month results in a net credit to the Customer, the Authority will issue the credit in the form of a check if it is greater than or equal to $50.00. If the credit is less than $50.00, then it will be applied to the next billing month.

(B) The Authority will furnish, install, own and maintain metering to measure the kilowatt demand delivered by the Authority to the Customer, and to measure the net kilowatt-hours purchased by the Customer or delivered to the Authority. The Authority shall have the right to install special metering and load research devices on the Customer's equipment and the right to use the Customer's telephone line for communication with the Authority's and the Customer's equipment.

(C) If the Customer is not the owner of the premises receiving electric service from the Authority, the Authority shall have the right to require that the owner of the premises give satisfactory written approval of the Customer's request for service under this Rider.

(D) The Authority reserves the right to terminate the Customer's service under this Rider at any time upon written notice to the Customer in the event that the Customer violates any of the terms or conditions of this Rider or the Interconnection Standard, or operates the generation system and equipment in a manner which is detrimental to the Authority or any of its customers.

(E) While receiving service from the Authority under this Rider, the Customer-Generator may retain ownership of any Renewable Energy Credits produced by the Customer-Generator's system. The Authority reserves the right to adjust this Section 3 (E) regarding the ownership of Renewable Energy Credits at its discretion in the future.

(F) Due to the experimental nature of this Rider, the Authority may deem it necessary to re-evaluate this Rider and, as with all schedules, reserves the right to revise, eliminate, or close this Rider to new customers; provided, however, that this Rider shall not be closed prior to December 31, 2020 to any existing Customer receiving service under this Rider.

Section 4. Monthly Rates & Charges:

(A) Basic Monthly Charges:

(1) Metering Charge:
For each month, a charge of …………………………………………………..$9.00

(2) Stand-By Charge:
For each kW of installed capacity, a monthly charge of:
e) Residential ……………………………………………………………$4.70
f) Commerical …………………………………………………………..$5.00

(3) Energy Credits:

All kWh during the Summer Season $0.0419/kWh

All kWh during the Non-Summer Season $0.0408/kWh

Summer Season – The Summer Season energy credit shall apply to all kWh delivered from the Customer-Generator to the Authority for bills rendered during the months of June, July, August and September. Energy credits for such bills shall not be prorated for periods outside of these four calendar months.

Non-Summer Season – The Non-Summer Season energy charge shall apply for all kWh delivered from the Customer-Generator to the Authority for bills rendered in months other than the Summer Season.

(4) Energy Charges:
As set forth in the applicable rate schedule.

(H) Adjustments to Energy Credits:

The Energy Credits shall be adjusted at least annually to reflect changes in the Authority's determination of its projected cost of energy.

(I) Minimum Charge:

The monthly minimum charge shall be the "Customer Charge" as determined by the applicable rate schedule plus the "Metering Charge" plus any applicable "Stand-By or Demand Charges". Customers taking service under any demand-metered rate schedules shall be exempt from Stand-By Charges.

(J) Taxes:

Amounts for "payments in lieu of taxes", as prescribed by the Code of Laws of South Carolina §58-31-80, §58-31-90, and §58-31-100, as amended, have been included in the establishment of the above monthly rate. The charges computed at the above monthly rate also shall be subject to all other taxes, payments in lieu of taxes, franchise fee, and surcharges imposed by any governmental authority. In addition, South Carolina Sales Tax, if any, will be added to each bill unless the Customer has furnished the Authority evidence of specific exemption secured by the Customer from the South Carolina Tax commission or its successor.

Section 5. Payment:

Bills will be rendered monthly on a net basis. All bills are due and payable at the offices of the Authority or at such other place as the Authority may designate within 15 days after the date on which the bill is mailed or otherwise rendered. If payment is not received by said due date, the amount of the bill will be increased on the next bill rendered and on subsequent bills rendered each month thereafter until paid by the larger of fifty cents ($.50) or two percent (2%) of the amount then outstanding including late payment charges.

Section 6. Terms and Conditions:

Service hereunder is subject to the Authority's "Terms and Conditions of Retail Electric Service" currently in effect which is available at the Authority's retail offices.

Adopted _________, 2015
Effective for bills rendered on and after April 1, 2018

Supersedes:
Schedule DG-17, Effective April 1, 2017

Appendix C
TECHNICAL APPENDIX (SEPARATE DOCUMENT)

Revenue Requirements	Red		Overall Ann Rev Req
1- Functionalization and Classification of Revenue Requirements	Blue		
Revenue Requirements by Major Functional Classification			Functional Class
Revenue Requirements by Functional Component			Functional Component
Functional O&M Expenses			Functional O&M
Projected Generation and Fuel Costs Summary			Projected Gen and Fuel
Classification of Distribution Expenses			Classification of Dist Exp
Classification of Administrative and General Expenses			Classification of A&G
Functionalization of Salaries and Wages Expenses			Functional Wages and Salarie
Classification of Production Wages and Salaries			Classification Wages and Salar
Classification of Production O&M Expenses			Classification O&M
Classification of Sums in Lieu of Taxes			Classification Sums in Lieu
Functionalization of Debt Service Requirements			Functional Debt Service
2 - Allocation Factors	Green		
Demand and Energy Allocation Factors		2016 Allocation Factors	2017 Allocation Factors
Customer Allocations Summary			Customer Allocations
Projected Coincident Demands			Coincident Demands
Projected Energy Sales and Generation Requirements			Energy Sales and Generation
Projected Numbers of Customers			Number of Customers
Projected Load Data- Residential Class			Load Data- Residential
Projected Load Data- Commercial Class			Load Data- Commercial
Projected Load Data- Lighting Class			Load Data- Lighting
Projected Load Data- Industrial Class			Load Data- Industrial
Projected Load Data- Wholesale			Load Data- Wholesale
Projected Load Data- Off-System Sales			Load Data- Off-System
3 - Allocated Cost of Service Studies	Yellow		
Allocated Cost of Service Study			Allocated Cost of Service
Allocated Cost of Service By Rate Class- Residential, Commercial and Lighting		2016 Allocation- Distribution	2017 Allocation- Distribution
Residential Revenue Requirements by Major Functional Classification			Res
Commercial Revenue Requirements by Major Functional Classification			Comm
Lighting Revenue Requirements by Major Functional Classification			Light
Industrial Revenue Requirements by Major Functional Classification			Ind
4 - Projected Revenues Under Present Rates	Purple		
Projected Revenues Summary			Projected Rev Pres Summary
Projected Revenues Residential Class			Projected Rev Pres Res
Projected Revenues Commercial Class			Projected Rev Pres Comm
Projected Revenues Lighting Class			Projected Rev Pres Light
Projected Revenues Industrial			Projected Rev Pres Industrial
Projected Revenues from Wholesale			Projected Rev Pres Wholesale
Projected Revenues Off-System Sales			Projected Rev Pres Off-Systen
Projected Fuel Adjustment Factors			Projected Pres Fuel Adj Facto
Demand Sales Credits			Projected Pres DSC
Economic Development Credits			Projected Pres EDA
5 - Projected Revenues Under Proposed Rates	Orange		

Overall Annual Revenue Requirements
Test Years 2016-2018
(Dollars in Thousands)

Proposed 2016-2018
(Test Year Effective Dates)

Line	Description	2016 (a)	2017 (b)	2018 (c)	Description/Source [1]
	Operating Revenues				
	Revenues From Sales of Electricity At Presently Adopted Rates [2]				
1	On-System Sales	$1,814,411	$1,864,070	$1,876,686	From below.
2	Off-System Sales	$79,646	$86,744	$96,056	From below.
3	Total Sales of Electricity	$1,894,056	$1,950,813	$1,972,742	
4	Other Operating Revenues	$15,783	$16,585	$17,375	From below.
5	Total Operating Revenues	$1,909,839	$1,967,398	$1,990,117	
	Operating Expenses				
	Operations and Maintenance Expenses				
6	Fuel Expenses [3]	$759,697	$784,715	$793,329	SCFF, Sch. 1, Line 28.
7	Purchased Power	$136,796	$140,282	$135,388	SCFF, Sch. 1, Lines 17-19.
8	Non-fuel O&M Expenses	$229,840	$233,441	$238,907	SCFF, Sch. 1, Lines 5-16.
9	Total Production Expenses	$1,126,333	$1,158,438	$1,167,624	
10	Transmission Expenses	$33,892	$33,104	$32,812	SCFF, Sch. 1, Line 30.
11	Distribution Expenses	$16,272	$16,311	$16,800	SCFF, Sch. 1, Line 31.
12	Customer Acct. & Info. Expenses	$16,469	$16,852	$17,358	SCFF, Sch. 1, Line 32.
13	Sales Expenses	$15,106	$14,594	$15,352	SCFF, Sch. 1, Line 33.
14	Admin. and General Expenses	$107,946	$110,854	$114,073	SCFF, Sch. 1, Line 34.
15	Total O&M Expenses	$1,316,018	$1,350,152	$1,364,019	
	Sums In Lieu of Taxes				
16	Franchise Taxes	$2,439	$2,510	$2,550	SCFF, Sch. 1, Line 35.
17	Other Sums	$326	$336	$348	SCFF, Sch. 1, Line 36.
18	Net Sums In Lieu of Taxes	$2,765	$2,846	$2,898	
19	Total Operating Expenses	$1,318,783	$1,352,998	$1,366,917	
20	Operating Income	$591,056	$614,400	$623,200	
21	Non-Operating Income	$17,771	$28,568	$25,352	SCFF, Sch. 1, Line 39.
22	Revenue Available For Debt Service and Other Purposes	$608,827	$642,968	$648,552	
	Debt Service On Senior Lien Debt				
23	Priority Bonds	$0	$0	$0	
24	Revenue & Revenue Obligation Bonds [4]	$411,112	$448,332	$459,482	SCFF, Sch. 1, Line 41.
25	Total Senior Lien Debt	$411,112	$448,332	$459,482	
26	Net Revenues After Senior Lien Debt	$197,715	$194,636	$189,070	
	Additional Debt Service				
27	Notes & Commercial Paper	$25,764	$19,760	$22,587	SCFF, Sch. 1, Lines 43-44.
28	Total Additional Debt Service	$25,764	$19,760	$22,587	
	Other Costs and Revenue Deductions				
29	Interest on Customer Deposits	$161	$168	$176	SCFF, Sch. 1, Line 45.
30	Payment to State	$19,433	$20,201	$20,640	SCFF, Sch. 1, Line 48.
31	One Time Contribution to the State	$0	$0	$0	
32	Payments to Counties	$4,891	$5,083	$5,193	SCFF, Sch. 1, Line 47.
33	Total Other Costs	$24,485	$25,452	$26,009	
34	Working Capital Requirements	$0	$4,074	$2,311	
35	Balance Before Capital Improvements Fund	$147,466	$145,350	$138,163	
36	Capital Improv. Fund Requirement	$175,817	$182,780	$185,415	
37	Net Revenue Surplus (Deficit)	($28,351)	($37,430)	($47,253)	

Notes:
[1] "SCFF" refers to the "Electric System Summary and Detail Reports" of Santee Cooper's 1501 Forecast.
[2] Revenues include collected franchise taxes. Revenues from Financial Forecast.
[3] Excludes maintenance of rail cars charged to FERC Account 501 (steam fuel expenses).
[4] Includes Subsidy Received on Build America Bonds

Overall Annual Revenue Requirements
Test Years 2016-2018
(Dollars in Thousands)

Proposed 2016-2018
(Test Year Effective Dates)

Line	Description	2016 (a)	2017 (b)	2018 (c)	Description/Source [1]
	Cost Of Service				
38	O&M Expenses	$1,316,018	$1,350,152	$1,364,019	From above.
	Sums In Lieu of Taxes				
39	Operating Expenses (Excl. Franchise)	$326	$336	$348	From above.
40	Special Reserve	$24,324	$25,284	$25,833	From above.
41	Subtotal	$24,650	$25,620	$26,181	
	Debt Service				
42	Senior Lien Bonds	$411,112	$448,332	$459,482	From above.
43	Other Debt Service	$25,764	$19,760	$22,587	From above.
44	Interest on Customer Deposits	$161	$168	$176	From above.
45	Total Debt Service	$437,037	$468,260	$482,245	
46	Working Capital Requirements	$0	$4,074	$2,311	From above.
	Gross Revenue Requirements				
47	Before CIF Requirement	$1,777,705	$1,848,106	$1,874,756	
48	CIF Requirement	$175,817	$182,780	$185,415	
49	Total Revenue Requirements	$1,953,522	$2,030,886	$2,060,172	
	Less:				
50	Other Operating Revenues	($15,783)	($16,585)	($17,375)	From above.
51	Non-Operating Income [5]	($10,225)	($20,883)	($17,667)	From above.
52	Net Revenue Requirements	$1,927,514	$1,993,418	$2,025,130	
53	Less: Off-System Sales	($79,646)	($86,744)	($96,056)	From above.
54	Net On-System Revenue Requirements	$1,847,869	$1,906,674	$1,929,074	
	Revenues From Sales				
55	At Present Rates (Excl. Franchise Tax)	$1,891,617	$1,948,303	$1,970,192	From below.
56	Less: Off-System Sales	($79,646)	($86,744)	($96,056)	From below.
57	On-System Revenues	$1,811,972	$1,861,560	$1,874,136	
58	Revenue Increase Justified	$35,897	$45,115	$54,938	
59	Percent of On-System Revenues	1.98%	2.42%	2.93%	
	Revenue Requirements Reconciliation				
60	Total Excl. CIF	$1,777,705	$1,848,106	$1,874,756	
61	Plus CIFR	$175,817	$182,780	$185,415	
62	Total Revenue Requirement	$1,953,522	$2,030,886	$2,060,172	
63	From Fin. Forecast Excl. Work. Cap. [5]	$1,953,497	$2,026,382	$2,057,604	SCFF, Sch. 1, Line 53.
64	Working Capital Requirements	$0	$4,477	$2,540	SCFF, Sch. 1, Line 54.
65	Net Excl. Franchise Taxes	$1,953,497	$2,030,859	$2,060,144	
66	CIFR	$175,815	$182,777	$185,413	
67	Net Before CIFR	$1,777,683	$1,848,082	$1,874,731	
68	Unaccounted For Costs	$25	$27	$28	

Notes:
[5] Exclude subsidy received on Build America Bonds
[6] Includes subsidy received on Build America Bonds

Overall Annual Revenue Requirements
Test Years 2016-2018
(Dollars in Thousands)

Proposed 2016-2018
(Test Year Effective Dates)

Line	Description	2016 (a)	2017 (b)	2018 (c)	Description/Source [1]
	Revenues From Sales of Electricity At Presently Adopted Rates				
	FRS Calculations				
	On-System Sales				
	Distribution Service				
69	Before Franchise Taxes	$392,720	$404,121	$410,598	Input (FRS Calculation).
70	Franchise Taxes	$2,439	$2,510	$2,550	SCFF, Sch. 1, Line 35.
71	Total Distribution Service	$395,159	$406,631	$413,148	
72	Industrials	$236,924	$242,453	$243,378	Input (FRS Calculation).
73	Cooperatives	$1,182,327	$1,214,986	$1,220,160	Input (FRS Calculation).
74	Total On-System Sales	$1,814,411	$1,864,070	$1,876,686	
75	Off-System Sales	$79,646	$86,744	$96,056	Input (FRS Calculation).
76	Total Sales of Electricity	$1,894,056	$1,950,813	$1,972,742	
77	Other Operating Revenues	$15,783	$16,585	$17,375	SCFF, Sch. 18, Line 6.
78	Total Operating Revenues	$1,909,839	$1,967,398	$1,990,117	
79	Total Excluding Franchise Taxes	$1,907,400	$1,964,888	$1,987,567	
	Revenues From Financial Forecast [7]				
	On-System Sales				
	Distribution Service				
80	Before Franchise Taxes	$389,597	$400,922	$407,369	SCFF, EX VI, Line 1.
81	Franchise Taxes	$2,439	$2,510	$2,550	SCFF, Sch. 1, Line 35.
82	Total Distribution Service	$392,036	$403,432	$409,919	
83	Industrials	$236,954	$242,509	$243,469	SCFF, EX VI, Line 2.
84	Wholesale	$1,185,383	$1,219,583	$1,224,867	SCFF, EX VI, Lines 3-4.
85	Total On-System Sales	$1,814,373	$1,865,524	$1,878,255	
86	Off-System Sales	$79,731	$86,830	$96,142	SCFF, EX VI, Line 5.
87	Total Sales of Electricity	$1,894,104	$1,952,354	$1,974,397	
88	Other Operating Revenues	$15,783	$16,585	$17,375	SCFF, Sch. 18, Line 6.
89	Total Before Proj Rate Adj	$1,909,887	$1,968,939	$1,991,772	
90	Projected Rate Adj	$35,833	$53,641	$74,803	
91	Total Revenue	$1,945,720	$2,022,580	$2,066,575	
92	Difference in Revenues	($48)	($1,541)	($1,655)	

Notes:
[7] Does not include all updates to billing determinants

Revenue Requirements By Major Functional Classification ($000)
Test Year 2016
(Dollars in Thousands)

Description	Total	Production Demand	Production Energy	Transmission	Distribution	Customer Accounts	Sales & Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Operation & Maintenance Expenses							
Production:							
Fuel	759,697	37,985	721,712	0	0	0	0
Purchased Power	136,795	30,473	106,322	0	0	0	0
Other Production O&M	229,840	157,915	71,925	0	0	0	0
Total Production O&M	1,126,332	226,373	899,959	0	0	0	0
Transmission Expenses	33,892	0	0	33,892	0	0	0
Distribution Expenses	16,272	0	0	0	15,106	1,166	0
Customer Accts., Svc. & Info. Exp.	16,469	0	0	0	0	16,469	0
Sales Expenses	15,106	0	0	0	0	0	15,106
Administrative & General - Labor	100,442	56,428	11,580	16,156	8,206	7,461	610
- Property Ins.	7,470	7,128	0	258	84	1	0
- DSM Related	34	0	0	0	0	34	0
Total Administration & General	107,946	63,556	11,580	16,414	8,290	7,496	610
Total Operations & Maintenance Exp.	1,316,017	289,929	911,539	50,306	23,396	25,131	15,716
Sums in lieu of Taxes	5,217	5,217	0	0	0	0	0
Payment to State	19,433	16,077	51	2,171	967	164	3
One Time Contribution to the State	0	0	0	0	0	0	0
Subtotal	24,650	21,294	51	2,171	967	164	3
Debt Service and Lease Payments							
Bonds & Other Borrowed Funds	437,038	361,566	1,147	48,827	21,754	3,683	60
Lease Payments	0	0	0	0	0	0	0
Total Debt Service & Lease Payments	437,038	361,566	1,147	48,827	21,754	3,683	60
Working capital	0	0	0	0	0	0	0
Total Revenue Req. Before CIFR	1,777,705	672,789	912,737	101,304	46,117	28,979	15,779
CIF Requirement	175,817	145,455	461	19,643	8,752	1,482	24
Gross Requirement	1,953,522	818,244	913,199	120,947	54,869	30,460	15,803
Less: Interest and Miscellaneous Income	(10,225)	(8,459)	(27)	(1,142)	(509)	(86)	(1)
Other Operating Revenues	(15,783)	(8,962)	0	(4,483)	(538)	(1,800)	0
Off-System Sales	(79,646)	(23,090)	(56,556)	0	0	0	0
Net On-System Requirements	1,847,869	777,733	856,616	115,322	53,822	28,574	15,802
Less Non-Firm Sales	(166,425)	(40,404)	(113,669)	(12,352)	0	0	0
Less Wholesale Power Sales	(1,177,410)	(540,923)	(549,667)	(83,698)	0	(3,123)	0
Total Cost of Service	**504,033**	**196,406**	**193,280**	**19,272**	**53,822**	**25,452**	**15,802**

Revenue Requirements By Major Functional Classification ($000)
Test Year 2017
(Dollars in Thousands)

Description	Total	Production Demand	Production Energy	Transmission	Distribution	Customer Accounts	Sales & Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Operation & Maintenance Expenses							
Production:							
Fuel	784,715	39,236	745,479	0	0	0	0
Purchased Power	140,282	31,941	108,340	0	0	0	0
Other Production O&M	233,441	164,332	69,109	0	0	0	0
Total Production O&M	1,158,438	235,509	922,928	0	0	0	0
Transmission Expenses	33,104	0	0	33,104	0	0	0
Distribution Expenses	16,311	0	0	0	15,141	1,169	0
Customer Accts., Svc. & Info. Exp.	16,852	0	0	0	0	16,852	0
Sales Expenses	14,594	0	0	0	0	0	14,594
Administrative & General - Labor	103,148	58,018	11,866	16,554	8,416	7,668	626
- Property Ins.	7,671	7,343	0	248	79	1	0
- DSM Related	34	0	0	0	0	34	0
Total Administration & General	110,854	65,361	11,866	16,802	8,495	7,703	626
Total Operations & Maintenance Exp.	1,350,152	300,871	934,795	49,906	23,636	25,725	15,219
Sums in lieu of Taxes	5,419	5,419	0	0	0	0	0
Payment to State	20,201	16,877	42	2,215	918	147	2
One Time Contribution to the State	0	0	0	0	0	0	0
Subtotal	25,620	22,296	42	2,215	918	147	2
Debt Service and Lease Payments							
Bonds & Other Borrowed Funds	468,260	391,200	974	51,347	21,271	3,417	51
Lease Payments	0	0	0	0	0	0	0
Total Debt Service & Lease Payments	468,260	391,200	974	51,347	21,271	3,417	51
Working capital	4,074	924	2,756	172	81	88	52
Total Revenue Req. Before CIFR	1,848,106	715,290	938,567	103,640	45,906	29,377	15,325
CIF Requirement	182,780	152,700	380	20,043	8,303	1,334	20
Gross Requirement	2,030,885	867,991	938,948	123,682	54,209	30,711	15,345
Less: Interest and Miscellaneous Income	(20,883)	(17,446)	(43)	(2,290)	(949)	(152)	(2)
Other Operating Revenues	(16,585)	(9,109)	0	(4,984)	(602)	(1,890)	0
Off-System Sales	(86,744)	(24,211)	(62,533)	0	0	0	0
Net On-System Requirements	1,906,673	817,224	876,371	116,408	52,658	28,669	15,343
Less Non-Firm Sales	(173,630)	(43,460)	(117,735)	(12,435)	0	0	0
Less Wholesale Power Sales	(1,208,765)	(561,906)	(559,313)	(84,361)	0	(3,185)	0
Total Cost of Service	**524,279**	**211,858**	**199,323**	**19,613**	**52,658**	**25,483**	**15,343**

Revenue Requirements By Major Functional Classification ($000)
Test Year 2018
(Dollars in Thousands)

Description	Total	Production Demand	Production Energy	Transmission	Distribution	Customer Accounts	Sales & Other
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Operation & Maintenance Expenses							
Production:							
Fuel	793,328	39,666	753,661	0	0	0	0
Purchased Power	135,388	32,687	102,701	0	0	0	0
Other Production O&M	238,907	164,777	74,130	0	0	0	0
Total Production O&M	1,167,623	237,131	930,492	0	0	0	0
Transmission Expenses	32,812	0	0	32,812	0	0	0
Distribution Expenses	16,800	0	0	0	15,596	1,204	0
Customer Accts., Svc. & Info. Exp.	17,358	0	0	0	0	17,358	0
Sales Expenses	15,352	0	0	0	0	0	15,352
Administrative & General - Labor	106,143	59,570	12,258	17,077	8,682	7,910	645
- Property Ins.	7,894	7,568	0	248	78	1	0
- DSM Related	36	0	0	0	0	36	0
Total Administration & General	114,073	67,137	12,258	17,325	8,760	7,947	645
Total Operations & Maintenance Exp.	1,364,018	304,268	942,750	50,137	24,356	26,509	15,998
Sums in lieu of Taxes	5,541	5,541	0	0	0	0	0
Payment to State	20,640	17,308	35	2,266	894	135	2
One Time Contribution to the State	0	0	0	0	0	0	0
Subtotal	26,181	22,849	35	2,266	894	135	2
Debt Service and Lease Payments							
Bonds & Other Borrowed Funds	482,245	404,383	816	52,949	20,889	3,165	43
Lease Payments	0	0	0	0	0	0	0
Total Debt Service & Lease Payments	482,245	404,383	816	52,949	20,889	3,165	43
Working capital	2,311	521	1,565	96	47	51	31
Total Revenue Req. Before CIFR	1,874,755	732,020	945,167	105,449	46,186	29,860	16,073
CIF Requirement	185,415	155,478	314	20,358	8,032	1,217	17
Gross Requirement	2,060,170	887,499	945,481	125,807	54,217	31,077	16,090
Less: Interest and Miscellaneous Income	(17,667)	(14,815)	(30)	(1,940)	(765)	(116)	(2)
Other Operating Revenues	(17,375)	(9,294)	0	(5,423)	(674)	(1,984)	0
Off-System Sales	(96,056)	(25,512)	(70,544)	0	0	0	0
Net On-System Requirements	1,929,072	837,878	874,907	118,444	52,778	28,977	16,088
Less Non-Firm Sales	(175,255)	(41,043)	(118,536)	(15,676)	0	0	0
Less Wholesale Power Sales	(1,213,137)	(583,047)	(553,910)	(72,968)	0	(3,213)	0
Total Cost of Service	**540,679**	**213,788**	**202,461**	**29,800**	**52,778**	**25,764**	**16,088**

Revenue Requirements By Functional Component
Test Year 2016
(Dollars in Thousands)

Line	Description	Total	Production Demand	Production Energy	Transmission	Distribution	Customer Accounts	Sales	Labor	Gross Plant	General Plant	Revenues	DSM	Lighting	Other
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	Operations & Maint. Expenses														
1	Production O&M Expenses	1,126,332	226,373	899,959	0	0	0	0	0	0	0	0	0	0	0
2	Transmission O&M Expenses	33,892	0	0	33,892	0	0	0	0	0	0	0	0	0	0
3	Distribution O&M Expenses	16,272	0	0	0	16,272	0	0	0	0	0	0	0	0	0
4	Cust. Accts., Svc. & Info.	16,469	0	0	0	0	16,469	0	0	0	0	0	0	0	0
5	Sales Expenses	15,106	0	0	0	0	0	15,106	0	0	0	0	0	0	0
6	Administrative & General	107,946	0	0	0	0	34	0	100,442	7,470	0	0	0	0	0
7	Total O&M Expenses	1,316,017	226,373	899,959	33,892	16,272	16,503	15,106	100,442	7,470	0	0	0	0	0
	Sums In Lieu of Taxes:														
8	Sums in Lieu of Prop. Taxes	193	0	0	0	0	0	0	0	193	0	0	0	0	0
9	Additional Sums - Spec. Res.	33	0	0	0	0	0	0	0	33	0	0	0	0	0
10	Land Rental Taxes	133	0	0	0	0	0	0	0	133	0	0	0	0	0
11	kWh Sales Tax	1,943	0	1,943	0	0	0	0	0	0	0	0	0	0	0
12	Generation Tax	2,915	0	2,915	0	0	0	0	0	0	0	0	0	0	0
13	Payment to State	19,433	0	0	0	0	0	0	0	0	0	19,433	0	0	0
14	Total Sums In Lieu of Taxes	24,650	0	4,858	0	0	0	0	0	359	0	19,433	0	0	0
	Debt Service:														
15	Production Plant	355,976	355,976	0	0	0	0	0	0	0	0	0	0	0	0
16	Transmission Plant	47,227	0	0	47,227	0	0	0	0	0	0	0	0	0	0
17	Distribution Plant	23,885	0	0	0	20,941	2,944	0	0	0	0	0	0	0	0
18	General Plant	9,949	5,590	1,147	1,600	813	739	60	0	0	0	0	0	0	0
19	Intangible Plant	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Customer Accounts	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Demand-Side Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	Direct Assign. to Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0
23	Total Debt Service	437,038	361,566	1,147	48,827	21,754	3,683	60	0	0	0	0	0	0	0
	Lease Payments														
24	Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	General	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Total Lease Payments	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Working Capital Requirement	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Gross Rev. Requirements (exc. CIF)	1,777,705	587,939	905,964	82,719	38,026	20,186	15,166	100,442	7,829	0	19,433	0	0	0