THIS FILING IS
Item 1: ☑ An Initial (Original) Submission OR ☐ Resubmission No.

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Dominion Energy South Carolina, Inc.	End of: 2022/ Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q) is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities, Licensees, and Others Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

1. one million megawatt hours of total annual sales,
2. 100 megawatt hours of annual sales for resale,
3. 500 megawatt hours of annual power exchanges delivered, or
4. 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

a. Submit FERC Form Nos. 1 and 3-Q electronically through the eCollection portal at https://eCollection.ferc.gov, and according to the specifications in the Form 1 and 3-Q taxonomies.

b. The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

c. Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:
Secretary
Federal Energy Regulatory Commission 888 First Street, NE
Washington, DC 20426

d. For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a. Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b. Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e. The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of [COMPANY NAME] for the year ended on which we have reported separately under date of [DATE], we have also reviewed schedules [NAME OF SCHEDULES] of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases." The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

f. Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. Further instructions are found on the Commission's website at https://www.ferc.gov/ferc-online/ferc-online/frequently-asked-questions-faqs-efilingferc-online.

g. Federal, State, and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/general-information-0/electric-industry-forms.

When to Submit

III. Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" included in the header of each page is to be completed only for resubmissions (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII. For any resubmissions, please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

X. Schedule specific instructions are found in the applicable taxonomy and on the applicable blank rendered form.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

3. 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;
4. 'Person' means an individual or a corporation;
5. 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;
7. 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......
11. "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

FERC Forms 1 and 3-Q must be filed by the following schedule:

a. FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and
b. FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. **Where to Send Comments on Public Reporting Burden.**

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

Sec. 4. The Commission is hereby authorized and empowered

a. 'To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304.

a. Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may by rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309.

The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

GENERAL PENALTIES

The Commission may assess up to $1 million per day per violation of its rules and regulations. See FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1 REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER		
IDENTIFICATION		
01 Exact Legal Name of Respondent Dominion Energy South Carolina, Inc.		02 Year/ Period of Report End of: 2022/ Q4
03 Previous Name and Date of Change (If name changed during year) /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 400 Otarre Parkway, Cayce SC 29033-3751		
05 Name of Contact Person Lisa Honeycutt		06 Title of Contact Person Accounting Manager
07 Address of Contact Person (Street, City, State, Zip Code) 220 Operation Way - MC B131, Cayce, SC 29033-3701		
08 Telephone of Contact Person, Including Area Code (803) 217-7416	09 This Report is An Original / A Resubmission (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) 03/24/2023
Annual Corporate Officer Certification		
The undersigned officer certifies that: I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.		
01 Name Mark F. Lindley 02 Title Controller	03 Signature Mark F. Lindley	04 Date Signed (Mo, Da, Yr) 03/24/2023
Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.		

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

26	**Transmission Service and Generation Interconnection Study Costs**	231	
27	**Other Regulatory Assets**	232	
28	**Miscellaneous Deferred Debits**	233	
29	**Accumulated Deferred Income Taxes**	234	
30	**Capital Stock**	250	
31	**Other Paid-in Capital**	253	
32	**Capital Stock Expense**	254b	
33	**Long-Term Debt**	256	
34	**Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax**	261	
35	**Taxes Accrued, Prepaid and Charged During the Year**	262	
36	**Accumulated Deferred Investment Tax Credits**	266	
37	**Other Deferred Credits**	269	
38	**Accumulated Deferred Income Taxes-Accelerated Amortization Property**	272	
39	**Accumulated Deferred Income Taxes-Other Property**	274	
40	**Accumulated Deferred Income Taxes-Other**	276	
41	**Other Regulatory Liabilities**	278	
42	**Electric Operating Revenues**	300	
43	**Regional Transmission Service Revenues (Account 457.1)**	302	N/A
44	**Sales of Electricity by Rate Schedules**	304	
45	**Sales for Resale**	310	
46	**Electric Operation and Maintenance Expenses**	320	
47	**Purchased Power**	326	
48	**Transmission of Electricity for Others**	328	
49	**Transmission of Electricity by ISO/RTOs**	331	N/A
50	**Transmission of Electricity by Others**	332	
51	**Miscellaneous General Expenses-Electric**	335	
52	**Depreciation and Amortization of Electric Plant (Account 403, 404, 405)**	336	
53	**Regulatory Commission Expenses**	350	
54	**Research, Development and Demonstration Activities**	352	
55	**Distribution of Salaries and Wages**	354	
56	**Common Utility Plant and Expenses**	356	
57	**Amounts included in ISO/RTO Settlement Statements**	397	
58	**Purchase and Sale of Ancillary Services**	398	
59	**Monthly Transmission System Peak Load**	400	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Mark F. Lindley

Controller

400 Otarre Parkway, Cayce, SC 29033-3751

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

State of Incorporation: SC

Date of Incorporation: 1924-07-19

Incorporated Under Special Law:

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

(a) Name of Receiver or Trustee Holding Property of the Respondent:

(b) Date Receiver took Possession of Respondent Property:

(c) Authority by which the Receivership or Trusteeship was created:

(d) Date when possession by receiver or trustee ceased:

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

South Carolina - Electric, Gas

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes

(2) ☑ No

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiaries for whom trust was maintained, and purpose of the trust.

The respondent is a wholly-owned subsidiary of SCANA Corporation (SCANA). SCANA is a South Carolina Corporation created in 1984 as a holding company. SCANA holds directly all of the Capital Stock of the respondent. Effective January 1, 2019, SCANA became a wholly-owned subsidiary of Dominion Energy, Inc.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	South Caroina Fuel Company, Inc.	Acquires, owns, provides financing for and sells to DESC nuclear fuel, certain fossil fuels and emission allowances.	0%	[(a)] footnote
2	South Carolina Generating Company, Inc.	Owns A. M. Williams Generating Station and sells electricity solely to DESC.	0%	[(b)] footnote
3	SRFI, LLC	A single member LLC holding investments in companies involved with re-engineered fuel.	0%	[(c)] footnote
4	Canadys Refined Coal, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(d)] footnote
5	Brandon Shores Coaltech, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(e)] footnote
6	Louisa Refined Coal, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(f)] footnote
7	Brunner Island Refined Coal, LLC	Manufactures and sells refined coal to reduce emissions.	0%	[(g)] footnote

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: FootnoteReferences

Control held by Dominion Energy South Carolina, Inc. (DESC) under the terms of a fuel contract. The accounts of South Carolina Fuel Company, Inc. are fully consolidated herein.

(b) Concept: FootnoteReferences

DESC has determined that it has a controlling financial interest in South Carolina Generating Company, Inc. under the terms of a Power Purchase Agreement. Accordingly, DESC consolidates the accounts of South Carolina Generating Company, Inc. for financial reporting under Generally Accepted Accounting Principles. Since South Carolina Generating Company, Inc. is a separate FERC reporting entity and per guidance from FERC staff, South Carolina Generating Company, Inc. has not been consolidated in this Form 1 report.

(c) Concept: FootnoteReferences

SRFI, LLC is a single member LLC in which DESC is the sole member and no stock was issued.

(d) Concept: FootnoteReferences

DESC holds a 40% interest in Canadys Refined Coal, LLC. The other member is AJG Coal, Inc. In the first quarter of 2021, demolition and removal of partnership equipment which was located at DESC's Cope Station site occurred.

(e) Concept: FootnoteReferences

DESC holds a 10% interest in Brandon Shores Coaltech, LLC. The other member is AJG Coal, Inc.

(f) Concept: FootnoteReferences

DESC holds a 10% interest in Louisa Refined Coal, LLC. Other members include AJG Coal, Inc. and LRC Holdings.

(g) Concept: FootnoteReferences

DESC holds a 20% interest in Brunner Island Refined Coal, LLC. The other member is AJG Coal, Inc. The decommission activities commenced in March of 2021 and were completed 6/27/2021. This partnership was formally dissolved on 9/21/22.

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OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)	Date Started in Period (d)	Date Ended in Period (e)
1			[b]0		
2	President	W. Keller Kissam	1,062,506		
3	Executive Vice President, Chief Financial Officer and Treasurer	[a] James R. Chapman	116,776		2022-11-23
4	Chief Executive Officer	Diane Leopold	778,594		
5	Executive Vice President, Chief of Staff and Corporate Secretary	Carter M. Reid	307,030		
6	Senior Vice President - Regulatory Affairs and Customer Experience	Corynne S. Arnett	157,733		
7	Senior Vice President - Nuclear Operations & Fleet Performance	Gerald T. Bischof	125,713		2022-04-01
8	Senior Vice President, Chief Legal Officer and General Counsel	Carlos M. Brown	243,094		
9	Senior Vice President, Controller and Chief Accounting Officer	Michele L. Cardiff	172,845		
10	Senior Vice President - Corporate Affairs & Communications	William L. Murray	258,487		
11	Vice President and General Manager - North Carolina & South Carolina Gas Distribution	D. Russell Harris	369,421		
12	Senior Vice President and Chief Nuclear Officer	Daniel G. Stoddard	450,027		
13	Senior Vice President – Administrative Services	W. Keith Windle	90,948	2022-03-01	
14	Vice President – Transmission & Delivery	M. Shaun Randall	550,690		
15	Vice President - Power Generation	Iris N. Griffin	614,924		
16	Vice President and Treasurer	Darius A. Johnson	63,527	2022-04-01	

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FOOTNOTE DATA

(a) Concept: OfficerName

James R. Chapman resigned as Treasurer effective, April 1, 2022 and resigned as Executive Vice President and Chief Financial Officer effective November 23, 2022.

(b) Concept: OfficerSalary

These officers are paid by Dominion Energy Services, Inc. and the amounts presented represent only Dominion Energy South Carolina's share of their salary expense.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), name and abbreviated titles of the directors who are officers of the respondent.
2. Provide the principle place of business in column (b), designate members of the Executive Committee in column (c), and the Chairman of the Executive Committee in column (d).

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)	Member of the Executive Committee (c)	Chairman of the Executive Committee (d)
1	R.M. Blue	Richmond, Virginia	false	false
2	W. K. Kissam (President)	Cayce, South Carolina	false	false
3	D. Leopold (Chief Executive Officer)	Richmond, Virginia	false	false
4	[a] J.R. Chapman	Richmond, Virginia	false	false

FOOTNOTE DATA

(a) Concept: NameAndTitleOfDirector
James. R. Chapman resigned as Executive Vice President, Director, and Chief Financial Officer effective November 23, 2022.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

INFORMATION ON FORMULA RATES

Does the respondent have formula rates?	☑ Yes ☐ No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number (a)	FERC Proceeding (b)
1	Schedule 1, Schedule 7, Schedule 8, Attachment H	ER10-516, ER10-855, ER10-1268, ER20-1836, ER22-1344

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

INFORMATION ON FORMULA RATES - FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	☑ Yes ☐ No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website.

Line No.	Accession No. (a)	Document Date / Filed Date (b)	Docket No. (c)	Description (d)	Formula Rate FERC Rate Schedule Number or Tariff Number (e)
1	20220516-5291	05/16/2022	ER10-516, ER10-855, ER10-1268	Annual Update Informational Filing	Schedule 1, 7, 8, Attachment H

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

INFORMATION ON FORMULA RATES - Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s). (a)	Schedule (b)	Column (c)	Line No. (d)
1	204-207	Electric Plant in Service	g	58
2	320-323	Electric Operation and Maintenance Expenses	b	96
3	320-323	Electric Operation and Maintenance Expenses	b	197
4	356	Common Utility Plant and Expenses	N/A	N/A

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Pages 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1.One combination electric and gas franchise agreement, Town of Holly Hill, was renewed during the first quarter of 2022 without payment of consideration.

One gas only franchise agreement, Town of Ridgeland, was renewed during the second quarter of 2022 without payment of consideration.

2. None

3. None

4. None

5. None

6. Short-term borrowings below have been authorized by FERC (Docket No. ES21-25-000).

The Company's obligations under non-affiliated short-term borrowing arrangements on the respective Balance Sheet dates were as follows:

12/31/2022 - $249,133,000

12/31/2021 - $0

In January 2021, DESC applied to FERC for a two-year renewal of its short-term borrowing authorization. On March 9, 2021, in Docket No. ES21-25-000, FERC granted DESC's request for a two-year renewal of its short-term borrowing authorization beginning on March 25, 2021. In January 2023, DESC applied to FERC for a two-year renewal of its short-term borrowing authorization. On March 15, 2023, in Docket No. ES23-26-000, FERC granted DESC's request for a two-year renewal of its short-term borrowing authorization beginning on March 25, 2023. DESC may issue short-term debt in amounts not to exceed $2.2 billion outstanding.

South Carolina Fuel Company, Inc. (Fuel Company), an affiliate of DESC is consolidated in this filing (see Note 1 to the Financial Statements). Fuel Company participates in an intercompany credit agreement with Dominion Energy.

At January 1, 2022, Fuel Company had borrowings outstanding under this credit agreement totaling $241,811,245. During 2022, Fuel Company borrowed $224,544,001 and repaid borrowings of $219,630,000. At December 31, 2022, Fuel Company had borrowings outstanding under this agreement totaling $246,725,246. These borrowings are recorded in FERC Account 233 - Notes Payable to Associated Companies. Interest charges associated with these borrowings are recorded in FERC Account 145 - Notes Receivable from Associated Companies. The interest charges are netted against the accounts payable account activity.

DESC has FERC approval to participate in an intercompany Credit Agreement with Dominion Energy under which DESC may have short-term borrowings outstanding up to $900 million. At January 1, 2022, DESC had borrowings outstanding under this credit agreement totaling $171,671,000. During 2022, DESC borrowed $2,875,708,872 and repaid borrowings of $2,563,468,872. At December 2022, DESC had borrowings outstanding under this agreement totaling $483,911,000. These borrowings are recorded in FERC Account 233 - Notes Payable to Associated Companies. Interest charges associated with these borrowings are recorded in FERC Account 145 - Notes Receivable from Associated Companies. The interest charges are netted against the accounts payable account activity.

DESC is obligated to with respect to an aggregate of $35 million of Industrial Revenue Bonds which are secured by letters of credit. These letters of credit expire, subject to renewal, in the fourth quarter of 2023.

For additional information, see Notes 6, 8 and 9 to the Financial Statements.

7. None

8. None

9. See Notes 3 and 12 to the Financial Statements.

10. None

12. Important Changes

Business Review
In November 2022, Dominion Energy announced the commencement of a business review of value-maximizing strategic business actions, alternatives to its current business mix and capital allocation and regulatory options which may assist customers to manage costs and provide greater predictability to its long-term, state-regulated utility value proposition. While the ultimate impacts cannot be estimated until the review is completed, which is expected in 2023, implementation of recommendations resulting from the business review could have a material impact on Dominion Energy's future results of operations, financial condition and/or cash flows.

Future Environmental Regulations
Climate Change
The federal government and several states in which Dominion Energy operates have announced a commitment to achieving carbon reduction goals. In February 2021, the U.S. rejoined the Paris Agreement, which establishes a universal framework for addressing GHG emissions. States may also enact legislation relating to climate change matters such as the reduction of GHG emissions and renewable energy portfolio standards., similar to the VCEA. To the extent legislation is enacted at the federal or state level that is more restrictive than the VCEA and/or Dominion Energy's commitment to achieving net zero emissions by 2050, compliance with such legislation could have a material impact to Dominion Energy's financial condition and/or cash flows.

State Actions Related to Air and GHG Emissions
In August 2017, the Ozone Transport Commission released a draft model rule for control of NOX emissions from natural gas pipeline compressor fuel-fire prime movers. States within the ozone transport region, including states in which Dominion Energy has natural gas operations, are expected to develop reasonably achievable control technology rules for existing sources based on the Ozone Transport Commission model rule. States outside of the Ozone Transport Commission may also consider the model rules in setting new reasonably achievable control technology standards. Several states in which Dominion Energy operates are developing or have announced plans to develop state-specific regulations to control GHG emissions, including methane. Dominion Energy cannot currently estimate the potential financial statement impacts related to these matters, but there could be a material impact to its financial condition and/or cash flows.

Inflation Reduction Act
The IRA includes provisions which impose an annual fee for waste methane emissions from the oil and natural gas industry beginning with emissions reported in calendar year 2024 to the extent that an entity's emissions exceed a stated threshold, with implementation to be addressed by future rulemaking by the EPA. Pending the completion of such rulemaking, the Company currently does not expect these provisions to materially affect its future results of operations, financial condition and/or cash flows.

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

Dodd-Frank Act
The Commodity Exchange Act (CEA), as amended by Title VII of the Dodd-Frank Act, requires certain over-the counter derivatives, or swaps, to be cleared through a derivatives clearing organization and, if the swap is subject to a clearing requirement, to be executed on a designated contract market or swap execution facility. Non-financial entities that use swaps to hedge or mitigate commercial risk may elect the end-user exception to the CEA's clearing requirements. Dominion Energy utilizes the end-user exception with respect to its swaps. If, as a result of changes to the rulemaking process, Dominion Energy can no longer utilize the end-user exception or otherwise becomes subject to mandatory clearing, exchange trading or margin requirements, it could be subject to higher costs due to decreased market liquidity or increased margin payments. In addition, Dominion Energy's swap dealer counterparties may attempt to pass-through additional trading costs in connection with changes to the rulemaking process. Due to the evolving rulemaking process, Dominion Energy is currently unable to assess the potential impact of the Dodd-Frank Act's derivative-related provisions on its financial condition, results of operations or cash flows.

Federal Income Tax Laws
Inflation Reduction Act
The IRA imposes a 15% alternative minimum tax on GAAP net income, as adjusted for certain items, of corporations in excess of $1 billion, for tax years beginning after December 31, 2022. Entities that are subject to the alternative minimum tax may use tax credits to reduce the liability by up to 75% and will receive a tax credit carryforward with an indefinite life that can be claimed against the regular tax in future years. Deferred taxes will continue to be measured at the regular tax rate. Pending additional guidance, the alternative minimum tax is not expected to have an effect on the assessment of the realizability of the Company's deferred tax assets or a material impact on the Company's future results of operations or cash flows.

13. The following changes in Company Officers and Directors became effective during 2022:

P. Rodney Blevins resigned as President, effective December 31, 2021. Mr. Blevins was elected President - Gas Distribution of Dominion Energy, Inc., effective January 1, 2022.

W. Keller Kissam, President - Electric Operations, was elected President, effective January 1, 2022. Mr. Kissam was also elected Director, effective November 24, 2022.

Douglas C. Lawrence was elected Vice President - Nuclear Engineering & Fleet Support, effective January 1, 2022. Mr. Lawrence, Vice President - Nuclear Engineering & Fleet Support, was elected Vice President - Nuclear Operations & Fleet Performance, effective August 1, 2022.

Mark D. Sartain, Vice President - Nuclear Engineering & Fleet Support, was elected Vice President - Nuclear Projects, effective January 1, 2022. Mr. Sartain resigned and retired from the Company , effective March 1, 2022.

W. Keith Windle was elected Senior Vice President - Administrative Services, effective March 1, 2022.

Darius A. Johnson was elected Vice President and Treasurer, effective April 1, 2022.

James R. Chapman, Director, Executive Vice President, Chief Financial Officer and Treasurer, resigned as Treasurer, effective April 1, 2022. Mr. Chapman resigned from the Company, effective November 23, 2022.

Keith C. Coffer Jr., Controller resigned as Controller of the Company, effective April 1, 2022. Mr. Coffer was appointed Controller of Public Service Company of North Carolina, Incorporated, The East Ohio Gas Company, Questar Gas Company, Hope Gas, Inc. and various other subsidiary companies of Dominion Energy, Inc., effective April 1, 2022, none of which were the Company.

Mark F. Lindley was appointed Controller, effective April 1, 2022.

Elizabeth L. Chester was elected Vice President - Regulatory Affairs, effective April 1, 2022.

Prabir Purohit, Vice President - Finance, was elected Vice President - Strategy, effective April 1, 2022.

Joseph A. Woomer was elected Vice President - New Business & Customer Solutions effective April 1, 2022.

James Holloway was elected Vice President - Nuclear Engineering & Fleet Support, effective August 1, 2022.

Gerald T. Bischof retired as Senior Vice President - Nuclear Operations & Fleet Performance, effective August 1, 2022.

Jason E. Williams, Vice President - Environmental, was elected Vice President - Environmental & Sustainability, effective September 1, 2022.

Carlos M. Brown, Senior Vice President, General Counsel and Chief Compliance Officer, was elected Senior Vice President, Chief Legal Officer and General Counsel, effective September 1, 2022.

Simon C. Hodges, resigned as Vice President - Financial Management effective December 31, 2022.

Steven D. Ridge was elected Senior Vice President and Chief Financial Officer effective November 24, 2022.

The following change in Company Officers became effective in 2023 before the submission of this report:

M. Brandon Phibbs was elected Vice President - Financial Management effective January 1, 2023.

George A. Lippard, III, Site Vice President - V. C. Summer Power Station retired from the Company effective January 30, 2023.

Robert Justice was elected Site Vice President - V. C. Summer Power Station effective February 1, 2023.

14. Not Applicable

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200	13,941,089,802	13,443,485,258
3	Construction Work in Progress (107)	200	514,217,273	455,263,567
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		14,455,307,075	13,898,748,825
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	5,620,270,875	5,446,634,770
6	Net Utility Plant (Enter Total of line 4 less 5)		8,835,036,200	8,452,114,055
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	48,564,107	852,246
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		120,440,247	142,677,977
9	Nuclear Fuel Assemblies in Reactor (120.3)		165,107,401	164,301,564
10	Spent Nuclear Fuel (120.4)		216,049,432	295,504,260
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	346,659,275	387,545,863
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		203,501,912	215,790,184
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,038,538,112	8,667,904,239
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		27,241,741	43,772,965
19	(Less) Accum. Prov. for Depr. and Amort. (122)		448,551	1,327,725
20	Investments in Associated Companies (123)			
21	Investment in Subsidiary Companies (123.1)	224	5,573	13,124
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		60,309	60,309
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		199,842,132	319,197,398
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)		211,620,705	130,514,568

31	Long-Term Portion of Derivative Assets - Hedges (176)			
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		438,321,909	492,230,639
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		[a]10,983,073	[b]54,128,851
36	Special Deposits (132-134)		10,000	6,807,848
37	Working Fund (135)		100	100
38	Temporary Cash Investments (136)			
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		227,284,438	220,356,466
41	Other Accounts Receivable (143)		150,661,332	149,919,620
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,817,741	5,839,009
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		17,050,376	[c]24,743,156
45	Fuel Stock (151)	227	63,773,029	42,992,386
46	Fuel Stock Expenses Undistributed (152)	227		
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	202,883,477	168,976,412
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227		
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	622,919	624,403
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227		989,327
55	Gas Stored Underground - Current (164.1)		29,223,948	16,972,985
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		9,229,700	7,888,197
57	Prepayments (165)		75,587,949	69,697,403
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)			
60	Rents Receivable (172)			
61	Accrued Utility Revenues (173)		188,423,470	139,097,583
62	Miscellaneous Current and Accrued Assets (174)		9,380,768	(2,782,565)
63	Derivative Instrument Assets (175)		252,398,982	148,135,913
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		211,620,705	130,514,568

65	Derivative Instrument Assets - Hedges (176)			
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)			
67	Total Current and Accrued Assets (Lines 34 through 66)		1,020,075,115	912,194,508
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		22,574,777	23,289,434
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	2,296,366,163	2,437,034,900
72	Other Regulatory Assets (182.3)	232	1,796,056,207	1,355,610,227
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,781,382	1,426,780
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)			
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	74,260,878	64,109,946
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		9,406,573	[(a)]10,500,746
82	Accumulated Deferred Income Taxes (190)	234	1,066,462,573	1,190,727,036
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		5,267,908,553	5,082,699,069
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		15,764,843,689	15,155,028,455

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: Cash

During 2022, $2,214,931 of Federal Customer Assistance Funds was applied against customer accounts. The remaining cash was returned to the Federal government.

(b) Concept: Cash

Includes $23,698,374 of Federal Customer Assistance Funds which are considered restricted cash.

(c) Concept: AccountsReceivableFromAssociatedCompanies

Reflects the reclassification from amounts reported in the Company's first quarter 2021 Form 3-Q report of $206,372,242 (debit activity) from Account 146 - Accounts Receivable from Associated Companies to Account 234 - Accounts Payable to Associated Companies related to repayment of borrowings from the SCANA Utility Money Pool.

(d) Concept: UnamortizedLossOnReacquiredDebt

In connection with the comprehensive settlement agreement in DESC's retail electric base rate case approved by the SCPSC (Docket No. 2020-125-E), in 2021 DESC wrote off $239.5 million of unamortized losses on reacquired debt that are no longer probable of recovery under the terms of the settlement agreement.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250	576,405,122	576,405,122
3	Preferred Stock Issued (204)	250	100,000	100,000
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)			
7	Other Paid-In Capital (208-211)	253	3,516,300,056	3,443,427,723
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b	4,335,379	4,335,379
11	Retained Earnings (215, 215.1, 216)	118	[a]417,628,866	[a]335,041,820
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118		
13	(Less) Reaquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	(1,517,180)	(582,602)
16	Total Proprietary Capital (lines 2 through 15)		4,504,581,485	4,350,056,684
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	3,722,814,000	3,722,814,000
19	(Less) Reaquired Bonds (222)	256		
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	1,110,003	1,142,917
22	Unamortized Premium on Long-Term Debt (225)		7,219,974	7,590,039
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		16,300,029	16,837,163
24	Total Long-Term Debt (lines 18 through 23)		3,714,843,948	3,714,709,793
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		23,525,583	26,284,208
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		4,105,031	4,473,191
29	Accumulated Provision for Pensions and Benefits (228.3)		116,192,785	166,568,695

30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Long-Term Portion of Derivative Instrument Liabilities			6,379,718
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		611,702,299	583,340,017
35	Total Other Noncurrent Liabilities (lines 26 through 34)		755,525,698	787,045,829
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		249,133,000	
38	Accounts Payable (232)		325,300,517	237,791,041
39	Notes Payable to Associated Companies (233)		(b)743,769,957	(d)414,563,708
40	Accounts Payable to Associated Companies (234)		134,661,571	(e)58,543,196
41	Customer Deposits (235)		71,956,986	70,996,666
42	Taxes Accrued (236)	262	272,392,558	255,328,027
43	Interest Accrued (237)		75,195,689	71,599,838
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		26,421,832	171,714,197
48	Miscellaneous Current and Accrued Liabilities (242)		128,175,861	162,625,626
49	Obligations Under Capital Leases-Current (243)		7,261,791	6,602,918
50	Derivative Instrument Liabilities (244)			7,212,444
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			6,379,718
52	Derivative Instrument Liabilities - Hedges (245)			
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges			
54	Total Current and Accrued Liabilities (lines 37 through 53)		2,034,269,762	1,450,597,943
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)			
57	Accumulated Deferred Investment Tax Credits (255)	266	14,189,650	15,486,622
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	60,699,463	55,765,267
60	Other Regulatory Liabilities (254)	278	2,510,661,611	2,733,859,640
61	Unamortized Gain on Reaquired Debt (257)		0	(f)0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	10,282,215	10,577,600
63	Accum. Deferred Income Taxes-Other Property (282)		1,250,537,444	1,216,325,872

64	Accum. Deferred Income Taxes-Other (283)		909,252,413	820,603,205
65	Total Deferred Credits (lines 56 through 64)		4,755,622,796	4,852,618,206
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		15,764,843,689	15,155,028,455

FOOTNOTE DATA

(a) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2022, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(b) Concept: NotesPayableToAssociatedCompanies

Includes borrowings outstanding, plus accrued interest, under the intercompany credit agreement with Dominion Energy as follows:

DESC	$	491,528,872
SCFC		252,241,085
Total	$	743,769,957

(c) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2021, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(d) Concept: NotesPayableToAssociatedCompanies

Includes borrowings outstanding, plus accrued interest, under the intercompany credit agreement with Dominion Energy as follows:

DESC	$	172,153,675
SCFC		242,410,033
Total	$	414,563,708

(e) Concept: AccountsPayableToAssociatedCompanies

Reflects the reclassification from amounts reported in the Company's first quarter 2021 Form 3-Q report of $206,372,242 (debit activity) from Account 146 - Accounts Receivable from Associated Companies to Account 234 - Accounts Payable to Associated Companies related to repayment of borrowings from the SCANA Utility Money Pool.

(f) Concept: UnamortizedGainOnReacquiredDebt

In connection with the comprehensive settlement agreement in DESC's retail electric base rate case approved by the SCPSC (Docket No. 2020-125-E), DESC wrote off $2.1 million of unamortized gains on reacquired debt that are no longer probable of being returned under the terms of the settlement agreement.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

6. Do not report fourth quarter data in columns (e) and (f)
7. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner to a utility department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
8. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended - Quarterly Only - No 4th Quarter (e)	Prior 3 Months Ended - Quarterly Only - No 4th Quarter (f)	Electric Utility Current Year to Date (in dollars) (g)	Electric Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1	UTILITY OPERATING INCOME											
2	Operating Revenues (400)	300	3,782,429,647	3,142,855,006			3,104,551,216	2,637,582,977	677,878,431	505,272,029		
3	Operating Expenses											
4	Operation Expenses (401)	320	2,052,571,436	1,538,741,771			1,549,791,852 (i)	1,185,830,927 (j)	502,779,584 (k)	352,910,844 (l)		
5	Maintenance Expenses (402)	320	179,516,003	161,621,931			169,767,135	153,877,885	9,748,868	7,744,046		
6	Depreciation Expense (403)	336	312,877,413	296,692,030			273,113,814	260,824,823	39,763,599	35,867,207		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336										
8	Amort. & Depl. of Utility Plant (404-405)	336	7,864,384	7,761,092			6,481,363	6,752,048	1,383,021	1,009,044		
9	Amort. of Utility Plant Acq. Adj. (406)	336	860,418	860,418			854,201	854,201	6,217	6,217		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		155,255,118	153,466,063			154,848,340	153,291,647	406,778	174,416		
11	Amort. of Conversion Expenses (407.2)											
12	Regulatory Debits (407.3)		16,302,258	15,269,143			16,302,258	15,269,143				
13	(Less) Regulatory Credits (407.4)		973,401	324,467			973,401	324,467				
14	Taxes Other Than Income Taxes (408.1)	262	268,866,976	246,970,760			238,294,418	215,793,608	30,572,558	31,177,152		
15	Income Taxes - Federal (409.1)	262	(33,204,682)	55,039,573			(44,048,195)	45,915,578	10,843,513	9,123,995		

16	Income Taxes - Other (409.1)	262	5,422,103	28,642,426			3,437,365	27,113,848	1,984,738	1,528,578		
17	Provision for Deferred Income Taxes (410.1)	234, 272	432,521,681	408,474,383			402,039,153	391,054,421	30,482,528	17,419,962		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	288,959,282	373,626,490			260,510,312	356,867,858	28,448,970	16,758,632		
19	Investment Tax Credit Adj. - Net (411.4)	266	(1,296,972)	(1,281,009)			(1,252,722)	(1,226,474)	(44,250)	(54,535)		
20	(Less) Gains from Disp. of Utility Plant (411.6)											
21	Losses from Disp. of Utility Plant (411.7)											
22	(Less) Gains from Disposition of Allowances (411.8)											
23	Losses from Disposition of Allowances (411.9)											
24	Accretion Expense (411.10)											
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,107,623,453	2,538,307,624			2,508,145,269	2,098,159,330	599,478,184	440,148,294		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		674,806,194	604,547,382			596,405,947	539,423,647	78,400,247	65,123,735		
28	Other Income and Deductions											
29	Other Income											
30	Nonutilty Operating Income											
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,031,101	1,050,258								
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		502,391	525,384								
33	Revenues From Nonutility Operations (417)		13,784,126	12,969,103								
34	(Less) Expenses of Nonutility Operations (417.1)		12,091,213	11,150,221								
35	Nonoperating Rental Income (418)		109,100	112,275								
36	Equity in Earnings of Subsidiary Companies (418.1)	119	[a]937	(2,548,723)								
37	Interest and Dividend Income (419)		6,378,185	9,845,969								
38	Allowance for Other Funds Used During Construction (419.1)		(33,704)	4,243,157								
39	Miscellaneous Nonoperating Income (421)		1,130,659	[d]4,199,515								
40	Gain on Disposition of Property (421.1)		[b]44,513,748	2,112,477								
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		54,320,548	20,308,426								
42	Other Income Deductions											
43	Loss on Disposition of Property (421.2)		[c]4,020,163									
44	Miscellaneous Amortization (425)		33,834	33,835								
45	Donations (426.1)		4,880,992	[e]22,985,786								
46	Life Insurance (426.2)		9,534	18,693								
47	Penalties (426.3)		821	[f](7,333,480)								
48	Exp. for Certain Civic, Political & Related Activities (426.4)		2,640,590	2,275,788								

49	Other Deductions (426.5)		13,724,670	[a]333,304,867								
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		25,310,604	351,285,489								
51	Taxes Applic. to Other Income and Deductions											
52	Taxes Other Than Income Taxes (408.2)	262	464,647	440,876								
53	Income Taxes-Federal (409.2)	262	(36,351,727)	(97,200,000)								
54	Income Taxes-Other (409.2)	262	(5,353,388)	(71,455,051)								
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	68,077,291	114,196,739								
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	15,349,118	55,084,433								
57	Investment Tax Credit Adj.-Net (411.5)											
58	(Less) Investment Tax Credits (420)											
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		11,487,705	(109,101,869)								
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		17,522,239	(221,875,194)								
61	Interest Charges											
62	Interest on Long-Term Debt (427)		190,967,172	183,287,944								
63	Amort. of Debt Disc. and Expense (428)		1,444,929	1,120,901								
64	Amortization of Loss on Reaquired Debt (428.1)		1,094,173	9,190,968								
65	(Less) Amort. of Premium on Debt-Credit (429)		370,065	352,447								
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			50,220								
67	Interest on Debt to Assoc. Companies (430)		12,052,249	1,081,466								
68	Other Interest Expense (431)		11,111,739	[b](16,918,633)								
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		6,558,810	2,825,432								
70	Net Interest Charges (Total of lines 62 thru 69)		209,741,387	174,534,547								
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		482,587,046	208,137,641								
72	Extraordinary Items											
73	Extraordinary Income (434)											
74	(Less) Extraordinary Deductions (435)											
75	Net Extraordinary Items (Total of line 73 less line 74)											
76	Income Taxes-Federal and Other (409.3)	262										
77	Extraordinary Items After Taxes (line 75 less line 76)											
78	Net Income (Total of line 71 and 77)		482,587,046	208,137,641								

FOOTNOTE DATA

(a) Concept: EquityInEarningsOfSubsidiaryCompanies

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

(b) Concept: GainOnDispositionOfProperty

Includes $19.5 million related to gain on sale of certain utility property and $21.5 million related to gain on sale of certain nonutility property.

(c) Concept: LossOnDispositionOfProperty

Includes $3.9 million write off to certain utility property.

(d) Concept: MiscellaneousNonoperatingIncome

Includes $2.1 million of unamortized gains on reacquired debt that were previously carried in Account 257 - Unamortized Gain on Reacquired Debt. In connection with the comprehensive settlement agreement approved by the SCPSC in DESC's retail electric base rate case (Docket No. 2020-125-E), DESC has determined that these amounts are no longer probable of return. Therefore, these amounts were written off to Account 421 in accordance with General Instruction 17 (J) of the Uniform System of Accounts.

(e) Concept: Donations

Includes $18 million of charges in connection with the comprehensive settlement agreement approved by the SCPSC in DESC's retail electric base rate case (Docket No. 2020-125-E).

(f) Concept: Penalties

In the fourth quarter of 2021, unrecognized tax benefits related to several state uncertain tax positions were effectively settled through negotiations with the taxing authority. Resolution of these uncertain tax positions resulted in the reversal of penalty expense.

(g) Concept: OtherDeductions

Includes charges of $70 million related to litigation and charges of $251 million in connection with the comprehensive settlement agreement approved by the SCPSC in DESC's retail electric base rate case (Docket No. 2020-125-E).

Included in the $251 million noted above are $239.5 million of unamortized losses on reacquired debt previously carried in Account 189 - Unamortized Loss on Reacquired Debt . Pursuant to the terms of the comprehensive settlement agreement, these amounts were deemed as being no longer probable of recovery and were written off to Account 426.5 in accordance with General Instruction 17(J) of the Uniform System of Accounts.

(h) Concept: OtherInterestExpense

In the fourth quarter of 2021, unrecognized tax benefits related to several state uncertain tax positions were effectively settled through negotiations with the taxing authority. Resolution of these uncertain tax positions resulted in the reversal of accrued interest.

(i) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $1,098,680 billed from Dominion Energy Services, Inc.

(j) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $1,549,434 billed from Dominion Energy Services, Inc.

(k) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $155,759 billed from Dominion Energy Services, Inc.

(l) Concept: OperationExpense

Includes depreciation charges, amortization charges, and property taxes $228,616 billed from Dominion Energy Services, Inc.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly report.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
4. State the purpose and amount for each reservation or appropriation of retained earnings.
5. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown for Account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		219,879,297	161,741,656
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
4.1				
4.2				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
10.1	Reclassification from Account 219 - Accumulated			
10.2	Other Comprehensive Income			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		482,586,109	210,686,364
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Federal Power Act Appropriation	215.1		
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1		238	(400,000,000)	(150,000,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(400,000,000)	(150,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		937	(2,548,723)
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		302,466,343	219,879,297
39	APPROPRIATED RETAINED EARNINGS (Account 215)			

45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		115,162,523	115,162,523
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		115,162,523	115,162,523
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		[a]417,628,866	[d]335,041,820
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)		[b]937	(2,548,723)
51	(Less) Dividends Received (Debit)			
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
52.1	Funded Equity Method Losses		[c]937	(2,548,723)
53	Balance-End of Year (Total lines 49 thru 52)			

FOOTNOTE DATA

(a) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2022, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

(b) Concept: EquityInEarningsOfSubsidiaryCompanies

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

(c) Concept: ChangesUnappropriatedUndistributedSubsidiaryEarningsCredits

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

(d) Concept: RetainedEarnings

DESC's articles of incorporation do not limit the dividends that may be paid on its common stock. However, DESC's bond indenture under which it issues First Mortgage Bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its surplus (as defined in the bond indenture) or (2) in case there is no surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year.

In addition, with respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2021, approximately $115.2 million were restricted by this requirement as to payment of cash dividends on common stock.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

STATEMENT OF CASH FLOWS

1. Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
2. Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
3. Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
4. Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions No.1 for explanation of codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 117)	482,587,046	208,137,641
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	312,961,028	296,791,471
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of Utility Plant and Acquisition Adjustment	8,758,636	8,655,344
5.2	Amortization - DER, Muni Franchise, Unrecovered Plt. & OCI	169,649,397	170,129,720
5.3	Amortization of Nuclear Fuel	38,568,240	33,591,683
8	Deferred Income Taxes (Net)	246,829,858	110,059,124
9	Investment Tax Credit Adjustment (Net)	(1,296,972)	(1,281,009)
10	Net (Increase) Decrease in Receivables	(61,782,127)	(104,830,095)
11	Net (Increase) Decrease in Inventory	(67,290,847)	(11,140,388)
12	Net (Increase) Decrease in Allowances Inventory	1,484	895
13	Net Increase (Decrease) in Payables and Accrued Expenses	113,859,756	159,293,631
14	Net (Increase) Decrease in Other Regulatory Assets	(413,933,166)	(98,053,028)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(326,741,616)	(156,573,754)
16	(Less) Allowance for Other Funds Used During Construction	(33,704)	4,243,157
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):	[a]40,331,321	[f]63,676,902
18.2	Discount / Premium on Long-Term Debt	167,069	130,335
18.3	Carrying Cost Recovery	(5,775,581)	(8,853,810)
18.4	(Gain) / Loss on Disposition of Assets	(38,860,898)	(684,332)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	498,066,332	664,807,173
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		

26	Gross Additions to Utility Plant (less nuclear fuel)		[(b)](648,226,217)	[(g)](588,585,758)
27	Gross Additions to Nuclear Fuel		(26,372,618)	(63,057,461)
28	Gross Additions to Common Utility Plant		[(c)](18,775,963)	[(h)](25,815,512)
29	Gross Additions to Nonutility Plant		[(d)]509,884	[(i)]965,907
30	(Less) Allowance for Other Funds Used During Construction		33,704	(4,243,157)
31	Other (provide details in footnote):			
31.1	Other (provide details in footnote):			
31.2	Salvage Received		4,288,856	4,253,436
31.3	Cost of Removal		(55,490,928)	[(j)](53,073,328)
34	Cash Outflows for Plant (Total of lines 26 thru 33)		(744,100,690)	(721,069,559)
36	Acquisition of Other Noncurrent Assets (d)			
37	Proceeds from Disposal of Noncurrent Assets (d)			
39	Investments in and Advances to Assoc. and Subsidiary Companies		8,489	(2,491,455)
40	Contributions and Advances from Assoc. and Subsidiary Companies			
41	Disposition of Investments in (and Advances to)			
42	Disposition of Investments in (and Advances to) Associated and Subsidiary Companies			
44	Purchase of Investment Securities (a)			
45	Proceeds from Sales of Investment Securities (a)			
46	Loans Made or Purchased			
47	Collections on Loans			
49	Net (Increase) Decrease in Receivables			
50	Net (Increase) Decrease in Inventory			
51	Net (Increase) Decrease in Allowances Held for Speculation			
52	Net Increase (Decrease) in Payables and Accrued Expenses			
53	Other (provide details in footnote):			
53.1	Proceeds-Sale of Fixed Assets & Investments		43,015,614	917,840
53.2	Other Investments		[(e)](1,874,906)	[(k)](3,144,283)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)		(702,951,493)	(725,787,457)
59	Cash Flows from Financing Activities:			
60	Proceeds from Issuance of:			
61	Long-Term Debt (b)			400,000,000
62	Preferred Stock			
63	Common Stock			
64	Other (provide details in footnote):			

64.1	Other (provide details in footnote):		
66	Net Increase in Short-Term Debt (c)	249,133,000	
67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Borrowings from Utility Money Pool & Intercompany Credit Agreement	3,100,252,873	5,377,311,856
67.3	Deferred Financing Costs / Long-Term Debt Issuance Costs	(191,713)	(2,848,000)
70	Cash Provided by Outside Sources (Total 61 thru 69)	3,349,194,160	5,774,463,856
72	Payments for Retirement of:		
73	Long-term Debt (b)	(4,355,905)	(40,639,868)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):		(a)(150,000,000)
76.2	Borrowings from Utilty Money Pool & Intercompany Credit Agreement	(2,783,098,872)	(5,318,714,853)
76.3	Premiums & Costs Related to Redemptions		
78	Net Decrease in Short-Term Debt (c)		
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(400,000,000)	(150,000,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	161,739,383	115,109,135
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	Net Increase (Decrease) in Cash and Cash Equivalents (Total of line 22, 57 and 83)	(43,145,778)	54,128,851
88	Cash and Cash Equivalents at Beginning of Period	54,128,951	100
90	Cash and Cash Equivalents at End of Period	10,983,173	54,128,951

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Includes ($50,375,910) for changes in the Company's net postretirement benefit obligation, $907,302 for Prepayments, $960,320 for Customer Deposits, ($30,609,908) liability reduction for property transfers for litigation settlements, $119,355,266 related to Year End Pension and Opeb Valuation and cash surrender value of Nuclear Decommissioning Trust Life Insurance and various other Balance Sheet changes not presented as separate line items.

(b) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

For the twelve months ended December 31, 2022, the Company added $6,429,808 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($5,753,482) for capital leases in accordance with USoA General instructions No. 20.

(c) Concept: GrossAdditionsToCommonUtilityPlantInvestingActivities

For the twelve months ended December 31, 2022, the Company added $64,080 to its Common Utility Plant Property Account (118) and reduced the same account by ($2,318,732) for capital leases in accordance with USoA General Instruction No. 20.

(d) Concept: GrossAdditionsToNonutilityPlantInvestingActivities

For the twelve months ended December 31, 2022, the Company added $0 to its Nonutility Plant Property Account (121) and reduced the same account by ($393,265) for capital leases in accordance with USoA General Instruction No. 20.

(e) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Nuclear Decommissioning Trust

(f) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Includes $237,471,406 for the net write off of unamortized losses and gains on reacquired debt, ($5,810,797) for changes in the Company's net postretirement benefit obligation, $2,565,218 for Prepayments, $823,383 for Customer Deposits and various other Balance Sheet changes not presented as separate line items.

Effective with the 2020 FERC Form No. 1 Report, cash flow related to interest rate swap collateral is being presented as an operating activity to conform with the presentation for such activity utilized by Dominion Energy. Activity for the current year reflects collateral returned of $700,000 and collateral posted of $0.

(g) Concept: GrossAdditionsToUtilityPlantLessNuclearFuelInvestingActivities

For the twelve months ended December 31, 2021, the Company added $0 to its Utility Plant Property Accounts (101.1 and 118) and reduced the same accounts by ($5,722,561) for capital leases in accordance with USoA General instructions No. 20

(h) Concept: GrossAdditionsToCommonUtilityPlantInvestingActivities

For the twelve months ended December 31, 2021, the Company added $988,421 to its Common Utility Plant Property Account (118) and reduced the same account by ($1,577,264) for capital leases in accordance with USoA General Instruction No. 20.

(i) Concept: GrossAdditionsToNonutilityPlantInvestingActivities

For the twelve months ended December 31, 2021, the Company added $0 to its Nonutility Plant Property Account (121) and reduced the same account by ($3,123,757) for capital leases in accordance with USoA General Instruction No. 20.

(j) Concept: OtherConstructionAndAcquisitionOfPlantInvestmentActivities

Effective with the 2020 FERC Form No. 1 Report, cash flow for cost of removal is being presented as an investing cash outflow, versus the historical treatment of being shown within operating activity, to conform with the presentation for such activity utilized by Dominion Energy.

(k) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Nuclear Decommissioning Trust

(l) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Return of Contributions from Parent

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

Glossary of Terms

The following abbreviations or acronyms used in this Form No. 1 are defined below:

Abbreviation or Acronym	Definition
2017 Tax Reform Act	An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (previously known as The Tax Cuts and Jobs Act) enacted on December 22, 2017
ACE Rule	Affordable Clean Energy Rule
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income (loss)
ARO	Asset retirement obligation
BACT	Best available control technology
bcf	Billion cubic feet
CAA	Clean Air Act
CCR	Coal combustion residual
CEO	Chief Executive Officer
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, also known as Superfund
CFO	Chief Financial Officer
CO2	Carbon dioxide
CUA	Capacity Use Area
CWA	Clean Water Act
DECG	Carolina Gas Transmission, LLC (formerly known as Dominion Energy Carolina Gas Transmission, LLC), a subsidiary of Berkshire Hathaway Energy Company effective November 2020 (previously a subsidiary of Dominion Energy)
DES	Dominion Energy Services, Inc.
DESC	The legal entity, Dominion Energy South Carolina, Inc., one or more of its consolidated entities or operating segment, or the entirety of Dominion Energy South Carolina, Inc. and its consolidated entities
DESS	Dominion Energy Southeast Services, Inc.
DOE	U.S. Department of Energy
Dominion Energy	The legal entity, Dominion Energy, Inc., one or more of its consolidated subsidiaries (other than DESC) or operating segments, or the entirety of Dominion Energy, Inc. and its consolidated subsidiaries
Dominion Energy South Carolina	Dominion Energy South Carolina operating segment
DSM	Demand-side management
ELG Rule	Effluent limitations guidelines for the steam electric power generating category
EMANI	European Mutual Association for Nuclear Insurance
EPA	U.S. Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ERISA	Employment Retirement Income Security Act of 1974
FERC	Federal Energy Regulatory Commission
FILOT	Fee in lieu of taxes
Fuel Company	South Carolina Fuel Company, Inc.
GAAP	U.S. generally accepted accounting principles
GENCO	South Carolina Generating Company, Inc.
GHG	Greenhouse gas
IRA	An Act to Provide for Reconciliation Pursuant to Title II of Senate Concurrent Resolution 14 of the 117th Congress (also known as the Inflation Reduction Act of 2022) enacted on August 16, 2022
IRS	Internal Revenue Service
LNG	Liquefied natural gas
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MGD	Million gallons per day
MW	Megawatt
MWh	Megawatt hour
NAV	Net asset value
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NND Project	V.C. Summer Units 2 and 3 nuclear development project under which DESC and Santee Cooper undertook to construct two Westinghouse AP1000 Advanced Passive Safety nuclear units in Jenkinsville, South Carolina
NOx	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
Order 1000	Order issued by FERC adopting requirements for electric transmission planning, cost allocation and development
ORS	South Carolina Office of Regulatory Staff
PGA	Purchased gas adjustment
PHMSA	U.S. Pipeline Hazardous Materials Safety Administration
Price-Anderson	Price-Anderson Amendments Act of 1988
PSD	Prevention of significant deterioration
Questar Gas	Questar Gas Company, a wholly-owned subsidiary of Dominion Energy
RICO	Racketeer Influenced and Corrupt Organizations Act
ROE	Return on equity
Santee Cooper	South Carolina Public Service Authority
SCANA	The legal entity, SCANA Corporation, one or more of its consolidated subsidiaries (other than DESC) or the entirety of SCANA Corporation and its consolidated subsidiaries
SCANA Combination	Dominion Energy's acquisition of SCANA completed on January 1, 2019 pursuant to the terms of the SCANA Merger Agreement
SCANA Merger Agreement	Agreement and plan of merger entered on January 2, 2018 between Dominion Energy and SCANA
SCANA Merger Approval Order	Final order issued by the South Carolina Commission on December 21, 2018 setting forth its approval of the SCANA Combination
SCDHEC	South Carolina Department of Health and Environmental Control
SCDOR	South Carolina Department of Revenue
Scope 1 emissions	Emissions that are produced directly by an entity's own operations
Scope 2 emissions	Emissions from electricity a company consumes but does not generate from its own facilities
Scope 3 emissions	Emissions generated downstream of company operations by customers and upstream by suppliers
SEC	U.S. Securities and Exchange Commission
SEEM	Southeast Energy Exchange Market
SO2	Sulfur dioxide
South Carolina Commission	Public Service Commission of South Carolina
Summer	V.C. Summer nuclear power station
Toshiba	Toshiba Corporation, parent company of Westinghouse
Toshiba Settlement	Settlement Agreement dated as of July 27, 2017, by and among Toshiba, DESC and Santee Cooper

VIE	Variable interest entity
Virginia Power	The legal entity, Virginia Electric and Power Company, a wholly-owned subsidiary of Dominion Energy, one or more of its consolidated subsidiaries or operating segment, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries
WECTEC	WECTEC Global Project Services, Inc., a wholly-owned subsidiary of Westinghouse
Westinghouse	Westinghouse Electric Company LLC
WNA	Weather normalization adjustment

The financial statements shown on pages 110 through 122 are prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than GAAP. The significant differences from the Company's GAAP requirements are related to the classification of certain assets and liabilities to include (i) the classification of restricted cash amounts within other current assets in the GAAP financial statements, whereas these amounts are included within cash in the FERC financial statements; (ii) the classification of a portion of regulatory assets and liabilities as current assets and liabilities in the GAAP financial statements, whereas these amounts are reported as deferred debits and credits in the FERC financial statements; (iii) the current portion of long term debt is not classified as a current liability in the FERC financial statements; (iv) certain affiliated payables and receivables are presented on a gross basis in the FERC financial statements, whereas these are reported on a net basis in the GAAP financial statements; (v) accumulated deferred income taxes are reported on a gross basis in the FERC financial statements, whereas these amounts are reported on a net basis by jurisdiction in the GAAP financial statements; (vi) the removal of unrecognized tax benefits for FERC reporting; (vii) accrued cost of removal is reported within accumulated provisions for depreciation in the FERC financial statements, whereas these amounts are reported within regulatory liabilities in the GAAP financial statements; (viii) debt issuance costs are reported within unamortized debt expense in the FERC financial statements, whereas these amounts are reported as a reduction to the carrying value of the debt in the GAAP financial statements; (ix) unamortized losses and gains on reacquired debt are reported within regulatory assets and liabilities in the GAAP basis financial statements and are separately presented within deferred debits and credits in the FERC financial statements; (x) the presentation of leases and the removal of regulatory assets recorded for GAAP reporting purposes related to leases; (xi) certain cloud computing arrangement costs are classified within net utility plant in the FERC financial statements whereas these amounts are included within prepayments on the GAAP basis statements; (xii) the non-service cost component of certain pension and other post employment benefits are reported within net utility plant and operation and maintenance expenses in the FERC financial statements, whereas these amounts are reported as regulatory assets and nonoperating expenses in the GAAP financial statements; and (xiii) the carrying value related to the planned retirement of certain peaking units is reported within net utility plant in the FERC financial statements until retirement, whereas these amounts are reported as regulatory assets in the GAAP financial statements. Also, certain charges associated with the abandonment of the NND Project are classified within operating income and taxes for GAAP reporting purposes, whereas these amounts are classified within nonoperating income (other deductions) for FERC reporting purposes. In addition, the accounts of GENCO are not consolidated herein, whereas they are so consolidated for GAAP reporting purposes.

The Company adopted revised GAAP accounting guidance for the recognition, measurement, presentation, and disclosure of leasing arrangements in 2019. For FERC reporting purposes, as a result of the adoption of this guidance, the Company established leased assets and liabilities for operating leases in the existing FERC balance sheet accounts for leases, in addition to the assets and liabilities the Company already maintained for its capital lease amounts which are now considered finance leases. The Company follows the accounting guidance set forth in General Instruction 20 of the Uniform System of Accounts. The operating lease assets established upon the adoption of this new accounting guidance have been excluded from rate base in the Company's FERC jurisdictional cost of service rates.

These notes are based on the notes contained in DESC's Annual Report on Form 10-K filed with the SEC and reflect certain reclassifications from the Uniform System of Accounts presentation shown on pages 110 through 122.
Management has evaluated the impact of events occurring after December 31, 2022 up to February 21, 2023, the date that DESC's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 24, 2023. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Dominion Energy South Carolina, Inc.
Notes to Consolidated Financial Statements

1. NATURE OF OPERATIONS

DESC is a wholly-owned subsidiary of SCANA, which is a wholly-owned subsidiary of Dominion Energy.

DESC is engaged in the generation, transmission and distribution of electricity in the central, southern and southwestern portions of South Carolina. Additionally, DESC distributes natural gas to residential, commercial and industrial customers in South Carolina.

DESC manages its daily operations through one primary operating segment: Dominion Energy South Carolina. It also reports a Corporate and Other segment that primarily includes specific items attributable to its operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

DESC's Consolidated Financial Statements include, after eliminating intercompany balances and transactions, the accounts of DESC and Fuel Company. DESC has concluded that Fuel Company is a VIE due to the member lacking the characteristics of a controlling financial interest. DESC is the primary beneficiary of Fuel Company and therefore is required to consolidate it. The equity interests in Fuel Company are held solely by SCANA, DESC's parent.

Fuel Company acquires, owns and provides financing for DESC's nuclear fuel, certain fossil fuels and emission and other environmental allowances. See also Note 6.

Additionally, effective January 2021, DESC purchases shared services from DES, an affiliated VIE that provides accounting, legal, finance and certain administrative and technical services to all Dominion Energy subsidiaries, including DESC. DESC previously purchased such services from DESS, an affiliated VIE, that had provided such services to all SCANA subsidiaries. DESC has determined that it is not the primary beneficiary of DES as it does not have either the power to direct the activities that most significantly impact its economic performance or an obligation to absorb losses and benefits which could be significant to it. See Note 16 for amounts attributable to affiliates.

DESC reports certain contracts and instruments at fair value. See Note 9 for further information on fair value measurements.

DESC maintains pension and other postretirement benefit plans. See Note 11 for further information on these plans.

Certain amounts in the 2021 and 2020 Consolidated Financial Statements and Notes have been reclassified to conform to the 2022 presentation for comparative purposes; however, such reclassifications did not affect DESC's net income, total assets, liabilities, equity or cash flows.

Utility Plant
Utility plant is stated at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and AFUDC, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

AFUDC is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFUDC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. DESC calculated AFUDC using average composite rates of 2.5%, 2.5% and 1.9% for 2022, 2021 and 2020, respectively. These rates do not exceed the maximum rates allowed in the various regulatory jurisdictions. DESC capitalizes interest on nuclear fuel in process at the actual interest cost incurred.
For property subject to cost-of-service rate regulation that will be abandoned significantly before the end of its useful life, the net carrying value is reclassified from utility plant-in-service when it becomes probable it will be abandoned and recorded as a regulatory asset for amounts expected to be collected through future rates.

Provisions for depreciation and amortization are recorded using the straight-line method based on the estimated service lives of the various classes of property, and in most cases, include provisions for future cost of removal. The composite weighted average depreciation rates for utility plant by function were as follows:

	2022(1)	2021
Generation	**2.29 %**	2.43 %
Transmission	**2.53 %**	2.56 %
Distribution	**2.50 %**	2.48 %
Storage	**2.80 %**	2.85 %
General and other	**3.05 %**	2.27 %

(1) Rates include the impact of a change in depreciation rates approved in connection with the settlement of the electric base rate case in 2021, which resulted in a decrease to depreciation expense of $12 million and $6 million for the years ended December 31, 2022 and 2021, respectively.

DESC records nuclear fuel amortization using the units-of-production method, which is included in fuel used in electric generation and recovered through the fuel cost component of retail electric rates.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine generator equipment, nuclear refueling outages and cyclical tree trimming and vegetation management are collected in rates and accrued in periods other than when incurred in accordance with approval by the South Carolina Commission for such accounting treatment and rate recovery of expenses accrued thereunder. The difference between such cumulative major maintenance costs and cumulative collections is classified as a regulatory asset or regulatory liability on the consolidated balance sheet. Other planned major maintenance is expensed when incurred.

Effective September 2021, DESC is authorized to collect $25 million annually through electric rates to offset certain turbine generator maintenance expenditures. Prior to September 2021, DESC was authorized to collect $18 million annually. For the years ended December 31, 2022, 2021 and 2020, DESC incurred $20 million, $20 million and $19 million, respectively, for turbine generator maintenance.

Nuclear refueling outages are scheduled 18 months apart. As approved by the South Carolina Commission, DESC accrues $17 million annually for its portion of the nuclear refueling outages, that are scheduled to occur from the fall of 2021 through the fall of 2027 as well as unrecovered balances from the previous accrual cycle. Refueling outage costs incurred for which DESC was responsible totaled $1 million in 2022, $24 million in 2021 and $23 million in 2020.

Effective September 2021, DESC implemented a tree trimming and vegetation management accrual where costs associated with cyclical tree trimming and vegetation management are accrued over the five-year operating cycle DESC seeks to maintain for such activities. As approved by the South Carolina Commission, DESC accrues $28 million annually. In 2021, DESC accrued $9 million during the period the accrual was effective. During the years ended December 31, 2022 and 2021, DESC incurred costs totaling $33 million and $9 million, respectively.

Asset Retirement Obligations

DESC recognizes AROs at fair value as incurred or when sufficient information becomes available to determine a reasonable estimate of the fair value of future retirement activities to be performed, for which a legal obligation exists. These amounts are generally capitalized as costs of the related tangible long-lived assets. Since relevant market information is not available, fair value is estimated using discounted cash flow analyses. Periodically, DESC assesses its AROs to determine if circumstances indicate that estimates of the amounts or timing of future cash flows associated with retirement activities have changed. AROs are adjusted when significant changes in the amounts or timing of future cash flows are identified. DESC reports accretion of AROs and depreciation on asset retirement costs as an adjustment to regulatory assets.

Nuclear Decommissioning

Based on a decommissioning cost study completed in 2020, DESC's two-thirds share of estimated site-specific nuclear decommissioning costs for Summer, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $788 million, stated in 2022 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer. The cost estimate assumes that the site will be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under DESC's method of funding decommissioning costs, DESC transfers to an external trust fund the amounts collected through rates ($3 million in each period presented), less expenses. The trust invests the amounts transferred into insurance policies on the lives of certain company personnel. Insurance proceeds are reinvested in insurance policies. The asset balance held in trust reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer on an after-tax basis.

Cash, Restricted Cash and Equivalents

Cash, restricted cash and equivalents include cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

Restricted Cash and Equivalents

Beginning in 2021, DESC may hold restricted cash and equivalent balances that consists of federal assistance funds to be used towards customer bill assistance.

The following table provides a reconciliation of the total cash, restricted cash and equivalents reported within DESC's Consolidated Balance Sheets to the corresponding amounts reported within DESC's Consolidated Statements of Cash Flows for the years ended December 31, 2022, 2021, 2020:

	Cash, Restricted Cash and Equivalents at End/Beginning of Year			
	December 31, 2022	December 31, 2021	December 31, 2020	December 31, 2019
(millions)				
Cash and cash equivalents	**$ 11**	$ 30	$ 5	$ 4
Restricted cash and equivalents(1)	**—**	24	—	—
Cash, restricted cash and equivalents shown in the Consolidated Statements of Cash Flows	**$ 11**	$ 54	$ 5	$ 4

(1) Restricted cash and equivalent balances are presented within other current assets on the Consolidated Balance Sheets.

Receivables

Customer receivables reflect amounts due from customers arising from the delivery of energy or related services and include both billed and unbilled amounts earned pursuant to revenue recognition practices described in Note 4. Customer receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis. Unbilled revenues totaled $188 million and $139 million at December 31, 2022 and 2021, respectively.

DESC sells electricity and natural gas and provides distribution and transmission services to customers in South Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of DESC's customer base, which includes a large number of residential, commercial and industrial customers. Credit risk associated with accounts receivable is limited due to the large number of customers. DESC's exposure to potential concentrations of credit risk results primarily from amounts due from Santee Cooper related to the jointly owned nuclear generating facility at Summer. Such receivables represented approximately 4% of DESC's accounts receivable balance at December 31, 2022.

Inventories

Materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when used. Fuel inventory includes the average cost of coal, natural gas, fuel oil and emission allowances. Fuel is charged to inventory when purchased and is expensed, at weighted average cost, as used and recovered through fuel cost recovery rates approved by the South Carolina Commission.

Income Taxes

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

DESC participates in an intercompany tax sharing agreement with Dominion Energy. Current income taxes are based on taxable income or loss and credits determined on a separate company basis. Under the agreements, if a subsidiary incurs a tax loss or earns a credit, recognition of current income tax benefits is limited to refunds of prior year taxes obtained by the carryback of the net operating loss or credit or to the extent the tax loss or credit is absorbed by the taxable income of other Dominion Energy consolidated group members. Otherwise, the net operating loss or credit is carried forward and is recognized as a deferred tax asset until realized.

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

DESC recognizes positions taken, or expected to be taken, in income tax returns that are more-likely-than-not to be realized, assuming that the position will be examined by tax authorities with full knowledge of all relevant information. At December 31, 2022 and 2021, DESC had $67 million and $61 million, respectively, of unrecognized tax benefits.

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

DESC recognizes interest on underpayments and overpayments of income taxes in interest expense and interest income, respectively. Penalties are also recognized in other expenses.

Interest expense at DESC was $3 million in 2022 and $7 million in 2020. In 2021, DESC reflected a $21 million benefit in interest expense and recognized a $7 million benefit from the reversal of penalty expenses associated with the effective settlement of uncertain tax positions.

Interest income at DESC was less than $1 million in 2022, 2021 and 2020. DESC recorded penalty expenses of $4 million in 2020.

At December 31, 2022, DESC had an income tax-related affiliated payable of $45 million to Dominion Energy. This balance is expected to be paid to Dominion Energy.

At December 31, 2021, DESC had an income tax-related affiliated receivable of $26 million from Dominion Energy. This balance was received from Dominion Energy in 2022.

At December 31, 2020, the Company had and income tax-related affiliated payable of $31 million to Dominion Energy. This balance was paid to Dominion Energy in 2021.

At DESC investment tax credits are deferred and amortized over the service lives of the properties giving rise to the credits. Production tax credits are recognized as energy is generated and sold.

Regulatory Assets and Liabilities

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

DESC evaluates whether or not recovery of its regulatory assets through future rates is probable as well as whether a regulatory liability due to customers is probable and makes various assumptions in its analyses. These analyses are generally based on:

- Orders issued by regulatory commissions, legislation and judicial actions;
- Past experience; and
- Discussions with applicable regulatory authorities and legal counsel.

Generally, regulatory assets and liabilities are amortized into income over the period authorized by the regulator. If recovery of a regulatory asset is determined to be less than probable, it will be written off in the period such assessment is made. A regulatory liability, if considered probable, will be recorded in the period such assessment is made or reversed into earnings if no longer probable. See Note 3 to the Consolidated Financial Statements for additional information.

Derivative Instruments

DESC is exposed to the impact of market fluctuations in the price of electricity and natural gas it markets and purchases, as well as interest rate risk in its business operations. DESC uses derivative instruments such as physical forwards and swaps to manage commodity and/or interest rate risks of its business operations.

Derivative assets and liabilities are presented gross on DESC's Consolidated Balance Sheets. Derivative contracts representing unrealized gain positions are reported as derivative assets. Derivative contracts representing unrealized losses are reported as derivative liabilities. All derivatives, except those for which an exception applies, are required to be reported in the Consolidated Balance Sheets at fair value. One of the exceptions to fair value accounting, normal purchases and normal sales, may be elected when the contract satisfies certain criteria, including a requirement that physical delivery of the underlying commodity is probable. Expenses and revenues resulting from deliveries under normal purchase contracts and normal sales contracts, respectively, are included in earnings at the time of contract performance. See Fair Value Measurements below for additional information about fair value measurements and associated valuation methods for derivatives.

DESC's derivative contracts include over-the-counter transactions. Over-the-counter contracts are bilateral contracts that are transacted directly with a third party. Certain over-the-counter contracts contain contractual rights of setoff through master netting arrangements and contract default provisions. In addition, the contracts are subject to conditional rights of setoff through counterparty nonperformance, insolvency, or other conditions.

In general, most over-the-counter transactions are subject to collateral requirements. Types of collateral for over-the-counter contracts include cash, letters of credit and, in some cases, other forms of security, none of which are subject to restrictions.

DESC does not offset amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. DESC had no margin assets or liabilities associated with cash collateral at December 31, 2022 and 2021. See Note 8 for further information about derivatives.

To manage price and interest rate risk, DESC holds derivative instruments that are not designated as hedges for accounting purposes. However, to the extent DESC does not hold offsetting position for such derivatives, it believes these instruments represent economic hedges that mitigate its exposure to fluctuations in commodity prices or interest rates. All income statement activity, including amounts realized upon settlement, is presented in operating expenses and interest charges based on the nature of the underlying risk. For derivative instruments that are not accounted for as cash flow hedges, the cash flows from the derivatives are classified in operating cash flows.

Changes in the fair value of derivative instruments result in the recognition of regulatory assets or regulatory liabilities. Realized gains or losses on the derivative instruments are generally recognized when the related transactions impact earnings.

DERIVATIVE INSTRUMENTS DESIGNATED AS HEDGING INSTRUMENTS

In accordance with accounting guidance pertaining to derivatives and hedge accounting, DESC designates a portion of their derivative instruments as cash flow hedges for accounting purposes. For derivative instruments that are accounted for as cash flow hedges, the cash flows from the derivatives and from the related hedged items are classified in operating cash flows.

Cash Flow Hedges- DESC uses interest rate swaps to hedge its exposure to variable interest rates on long-term debt. For transactions in which DESC is hedging the variability of cash flows, changes in the fair value of the derivatives are reported in regulatory assets or liabilities. Any derivative gains or losses reported in regulatory assets or liabilities are reclassified to earnings when the forecasted item is included in earnings, or earlier, if it becomes probable that the forecasted transaction will not occur. For cash flow hedge transactions, hedge accounting is discontinued if the occurrence of the forecasted transaction is no longer probable.

Pursuant to regulatory orders, interest rate derivatives entered into by DESC after October 2013 were not designated for accounting purposes as cash flow hedges, and fair value changes and settlement amounts related to them have been recorded as regulatory assets and liabilities. Settlement losses on swaps generally have been amortized over the lives of subsequent debt issuances, and gains have been amortized to interest charges or have been applied as otherwise directed by the South Carolina Commission.

Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (exit price) in an orderly transaction between market participants at the measurement date. However, the use of a mid-market pricing convention (the mid-point between bid and ask prices) is permitted. Fair values are based on assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. This includes not only the credit standing of counterparties involved and the impact of credit enhancements but also the impact of DESC's own nonperformance risk on its liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability (the market with the most volume and activity for the asset or liability from the perspective of the reporting entity), or in the absence of a principal market, the most advantageous market for the asset or liability (the market in which the reporting entity would be able to maximize the amount received or minimize the amount paid). DESC applies fair value measurements to certain assets and liabilities including commodity and interest rate derivative instruments. DESC applies credit adjustments to its derivative fair values in accordance with the requirements described above.

Inputs and Assumptions

Fair value is based on actively-quoted market prices, if available. In the absence of actively-quoted market prices, price information is sought from external sources, including industry publications, and to a lesser extent, broker quotes. When evaluating pricing information provided by Designated Contract Market settlement pricing, other pricing services, or brokers, DESC considers the ability to transact at the quoted price, i.e. if the quotes are based on an active market or an inactive market and to the extent which pricing models are used, if pricing is not readily available. If pricing information from external sources is not available, or if DESC believes that observable pricing is not indicative of fair value, judgment is required to develop the estimates of fair value. In those cases the unobservable inputs are developed and substantiated using historical information, available market data, third-party data and statistical analysis. Periodically, inputs to valuation models are reviewed and revised as needed, based on historical information, updated market data, market liquidity and relationships and changes in third-party sources.

The inputs and assumptions used in measuring fair value include the following:

	Derivative Contracts	
Inputs and assumptions	**Commodity**	**Interest Rate**
Forward commodity prices	X	
Transaction prices	X	
Volumes	X	
Commodity location	X	
Interest rates	X	
Interest rate curves		X
Credit quality of counterparties and DESC	X	X
Credit enhancements	X	X
Time value	X	X
Notional value		X

Levels

DESC utilizes the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

•Level 1-Quoted prices (unadjusted) in active markets for identical assets and liabilities that they have the ability to access at the measurement date.

•Level 2-Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include interest rate swaps.

•Level 3-Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments categorized in Level 3 for DESC consist of long-dated commodity derivatives.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. In these cases, the lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

Debt Issuance Costs

DESC defers and amortizes debt issuance costs and debt premiums or discounts over the expected lives of the respective debt issues, considering maturity dates and, if applicable, redemption rights held by others. Deferred debt issuance costs are recorded as a reduction in long-term debt in the Consolidated Balance Sheets. Amortization of the issuance costs is reported as interest charges. As permitted by regulatory authorities, gains or losses resulting from the refinancing or redemption of debt that are probable of recovery through future rates are deferred and amortized.

Environmental

An environmental assessment program is maintained to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in regulatory assets and, if applicable, amortized over approved amortization periods. Other environmental costs are expensed as incurred.

Statement of Operations Presentation

Revenues and expenses arising from regulated businesses are presented within operating income, and all other activities are presented within other income (expense), net.

Operating Revenue

Operating revenue is recorded on the basis of services rendered, commodities delivered, or contracts settled and includes amounts yet to be billed to customers. DESC collects sales, consumption, consumer utility taxes and sales taxes; however, these amounts are excluded from revenue and are recorded as liabilities until they are remitted to the respective taxing authority.

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

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

Revenue from Contracts with Customers

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

Other Revenue

- **Other revenue** consists primarily of alternative revenue programs, gains and losses from derivative instruments not subject to hedge accounting and lease revenues.

DESC records refunds to customers as required by the South Carolina Commission as a reduction to regulated electric sales or regulated gas sales, as applicable. Revenues from electric and gas sales are recognized over time, as the customers of DESC consume gas and electricity as it is delivered. Sales of products and services typically transfer control and are recognized as revenue upon delivery of the product or service. The customer is able to direct the use of, and obtain substantially all of the benefits from, the product at the time the product is delivered. The contract with the customer states the final terms of the sale, including the description, quantity and price of each product or service purchased. Payment for most sales and services varies by contract type, but is typically due within a month of billing.

DESC customers subject to an electric fuel cost recovery component or a PGA are billed based on a fuel or cost of gas factor calculated in accordance with cost recovery procedures approved by the South Carolina Commission and subject to adjustment periodically. Any difference between actual costs and amounts contained in rates is adjusted through revenue and is deferred and included when making the next adjustment to the cost recovery factors.

Certain amounts deferred for the WNA arise under specific arrangements with regulators rather than customers and are accounted for as an alternative revenue program. This alternative revenue is included within Other operating revenues, separate from revenue arising from contracts with customers, in the month such adjustments are deferred within regulatory accounts. As permitted, DESC has elected to reduce the regulatory accounts in the period when such amounts are reflected on customer bills without affecting operating revenues.

Performance obligations which have not been satisfied by DESC relate primarily to demand or standby service for natural gas. Demand or standby charges for natural gas arise when an industrial customer reserves capacity on assets controlled by the service provider and may use that capacity to move natural gas it has acquired from other suppliers. For all periods presented, the amount of revenue recognized by DESC for these charges is equal to the amount of consideration DESC has a right to invoice and corresponds directly to the value transferred to the customer.

Leases

DESC leases certain assets including vehicles, real estate, office equipment and other assets under both operating and finance leases. For operating leases, rent expense is recognized on a straight-line basis over the term of the lease agreement, subject to regulatory framework. Rent expense associated with operating leases, short-term leases and variable leases is primarily recorded in other operations and maintenance expense in the Consolidated Statements of Comprehensive Income (Loss). Amortization expense and interest charges associated with finance leases are deferred within regulatory assets in the Consolidated Balance Sheets and amortized into the Consolidated Statements of Comprehensive Income (Loss).

Certain leases include one or more options to renew, with renewal terms that can extend the lease from one to 70 years. The exercise of renewal options is solely at DESC's discretion and is included in the lease term if the option is reasonably certain to be exercised. A right-of-use asset and corresponding lease liability for leases with original lease terms of one year or less are not included in the Consolidated Balance Sheets, unless such leases contain renewal options that DESC is reasonably certain will be exercised.

The determination of the discount rate utilized has a significant impact on the calculation of the present value of the lease liability included in the Consolidated Balance Sheets. For DESC's leased assets, the discount rate implicit in the lease is generally unable to be determined from a lessee perspective. As such, DESC uses internally-developed incremental borrowing rates as a discount rate in the calculation of the present value of the lease liability. The incremental borrowing rates are determined based on an analysis of DESC's publicly available secured borrowing rates over various lengths of time that most closely corresponds to DESC's lease maturities.

3. RATE AND OTHER REGULATORY MATTERS

Regulatory Matters Involving Potential Loss Contingencies

As a result of issues generated in the ordinary course of business, DESC is involved in various regulatory matters. Certain regulatory matters may ultimately result in a loss; however, as such matters are in an initial procedural phase, involve uncertainty as to the outcome of pending reviews or orders, and/or involve significant factual issues that need to be resolved, it is not possible for DESC to estimate a range of possible loss. For regulatory matters that DESC cannot estimate, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the regulatory process such that DESC is able to estimate a range of possible loss. For regulatory matters that DESC is able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. Any estimated range is based on currently available information, involves elements of judgment and significant uncertainties and may not represent DESC's maximum possible loss exposure. The circumstances of such regulatory matters will change from time to time and actual results may vary significantly from the current estimate. For current matters not specifically reported below, management does not anticipate that the outcome from such matters would have a material effect on DESC's financial position, liquidity or results of operations.

2017 Tax Reform Act

DESC's provision of electric transmission service is pursuant to a FERC approved formula rate. In December 2019, FERC issued an order requiring transmission providers with transmission formula rates to account for the impacts of the 2017 Tax Reform Act on rates charged to customers. The order requires companies to include a mechanism to decrease or increase their income tax allowances to account for the 2017 Tax Reform Act and any other future changes in tax law, and to submit annual information reflecting the amortization of these excess deferred income taxes. DESC submitted a proposed update to its formula rate to FERC in May 2020, and DESC amended its proposed update in October 2021 and July 2022. In November 2022, FERC accepted DESC's proposed update, as amended, effective January 2020, which did not result in any impact to DESC's Consolidated Financial Statements.

Other Regulatory Matters

South Carolina Electric Base Rate Case

In August 2020, DESC filed its retail electric base rate case and schedules with the South Carolina Commission. In July 2021, DESC, the South Carolina Office of Regulatory Staff and other parties of record filed a comprehensive settlement agreement with the South Carolina Commission for approval. The comprehensive settlement agreement provided for a non-fuel, base rate increase of $62 million (resulting in a net increase of $36 million after considering an accelerated amortization of certain excess deferred income taxes) commencing with bills issued on September 1, 2021 and an authorized earned ROE of 9.50%. Additionally, DESC agreed to commit up to $15 million to forgive retail electric customer balances that were more than 60 days past due as of May 31, 2021 and provide $15 million for energy efficiency upgrades and critical health and safety repairs to customer homes. Pursuant to the comprehensive settlement agreement, DESC would not file a retail electric base rate case prior to July 1, 2023, such that new rates would not be effective prior to January 1, 2024, absent unforeseen extraordinary economic or financial conditions that may include changes in corporate tax rates. In July 2021, the South Carolina Commission approved the comprehensive settlement agreement and issued its final order in August 2021.

In connection with this matter, DESC recorded charges of $249 million ($187 million after-tax) reflected within impairment of assets and other charges (reflected in the Corporate and Other segment), including $237 million of regulatory assets associated with DESC's purchases of its first mortgage bonds during 2019 that are no longer probable of recovery under the settlement agreement, and $18 million ($14 million after-tax) reflected within other income (expense), net in its Consolidated Statements of Income for the year ended December 31, 2021.

Electric – Cost of Fuel

DESC's retail electric rates include a cost of fuel component approved by the South Carolina Commission which may be adjusted periodically to reflect changes in the price of fuel purchased by DESC. In February 2022, DESC filed with the South Carolina Commission a proposal to increase the total fuel cost component of retail electric rates. DESC's proposed adjustment is designed to recover DESC's current base fuel costs, including its existing under-collected balance, over the 12-month period beginning with the first billing cycle of May 2022. DESC also proposed to apply approximately $66 million representing the net balance of funds associated with the monetization of the bankruptcy settlement with Toshiba following the satisfaction of liens against NND Project property recorded in regulatory liabilities, as a reduction to its under-collected base fuel cost balance. In addition, DESC proposed an increase to its variable environmental and avoided capacity cost component. The net effect is a proposed annual increase of $143 million. In April 2022, the South Carolina Commission approved the filing.

In August 2022, DESC filed an application with the South Carolina Commission seeking a mid-period adjustment to increase the base fuel component of retail electric rates for the recovery of electric fuel costs. The application requested an increase of the base fuel cost component of $399 million, with rates expected to be effective with the first billing cycle of January 2023. In November 2022, DESC, the South Carolina Office of Regulatory Staff and other parties of record filed a stipulation agreement with the South Carolina Commission for approval that reflects updated fuel cost experience and forecasts. The stipulation agreement proposes an increase of the base fuel cost component to be effective with the first billing cycle of January 2023, with an estimated annual increase of $168 million. In December 2022, the South Carolina Commission approved the stipulation agreement and issued a final order.

In February 2023, DESC filed with the South Carolina Commission a proposal to increase the total fuel cost component of retail electric rates. DESC's proposed adjustment is designed to recover DESC's current base fuel costs, including its existing under-collected balance, over the 12-month period beginning with the first billing cycle of May 2023. In addition, DESC proposed a decrease to its variable environmental and avoided capacity cost component. The net effect is a proposed annual increase of $176 million. This matter is pending.

Electric – Other

DESC has approval for a DSM rider through which it recovers expenditures related to its DSM programs. In January 2022, DESC filed an application with the South Carolina Commission seeking approval to recover $60 million of costs and net lost revenues associated with these programs, along with an incentive to invest in such programs. In April 2022, the South Carolina Commission approved the request, effective with the first billing cycle of May 2022. In January 2023, DESC filed an application with the South Carolina Commission seeking approval to recover $46 million of costs and net lost revenues associated with these programs, along with an incentive to invest in such programs. DESC requested that rates be effective with the first billing cycle of May 2023. This matter is pending.

DESC utilizes a pension costs rider approved by the South Carolina Commission which is designed to allow recovery of projected pension costs, including under-collected balances or net of over-collected balances, as applicable. The rider is typically reviewed for adjustment every 12 months with any resulting increase or decrease going into effect beginning with the first billing cycle in May. In April 2022, the South Carolina Commission approved DESC's requested adjustment to this rider to decrease annual revenue by $12 million. In February 2023, DESC requested that the South Carolina Commission approve an adjustment to this rider to increase annual revenue by $24 million. This matter is pending.

Natural Gas Rates

In November 2021, DESC filed an application with the South Carolina Commission seeking approval to create DSM programs for DESC's residential and commercial natural gas customers and a new rider to retail gas rates for the recovery of the associated program costs and a shared savings incentive of 9.9%. The application also includes a notice of intent that DESC would seek to recover the net lost revenues resulting from the proposed DSM programs through the annual Natural Gas Rate Stabilization Act proceeding. In June 2022, the South Carolina Commission voted to approve the proposed DSM programs with a shared savings incentive of 8.14% with a final order issued in September 2022.

In June 2022, DESC filed with the South Carolina Commission its monitoring report for the 12-month period ended March 31, 2022 with a total revenue requirement of $553 million. This represents a $129 million overall annual increase to its natural gas rates including a $16 million base rate increase under the terms of the Natural Gas Rate Stabilization Act effective with the first billing cycle of November 2022. In October 2022, the South Carolina Commission issued an order approving a total revenue requirement of $549 million effective with the first billing cycle of November 2022. This represents a $125 million overall annual increase to DESC's natural gas rates including a $12 million base rate increase under the terms of the Natural Gas Rate Stabilization Act.

DESC's natural gas tariffs include a PGA that provides for the recovery of actual gas costs incurred, including transportation costs. DESC's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average, and its gas purchasing policies and practices are reviewed annually by the South Carolina Commission.

Regulatory Assets and Regulatory Liabilities

Rate-regulated utilities recognize in their financial statements certain revenues and expenses in different periods than do other enterprises. As a result, DESC has recorded regulatory assets and regulatory liabilities which are summarized in the following table.

Except for NND Project costs and certain other unrecovered plant costs, substantially all regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

At December 31,	2022	2021
(millions)		
Regulatory assets:		
NND Project costs(1)	**$ 138**	$ 138
Deferred employee benefit plan costs(2)	**4**	8
Other unrecovered plant(3)	**17**	16
DSM programs(4)	**21**	23
Cost of fuel and purchased gas under-collections(5)	**508**	126
Other	**54**	48
Regulatory assets - current	**742**	359
NND Project costs(1)	**2,088**	2,226
AROs(6)	**363**	294
Deferred employee benefit plan costs(2)	**161**	106
Interest Rate Hedges (7)	**167**	159
Other unrecovered plant(3)	**58**	57
DSM programs(4)	**41**	45
Environmental remediation costs(8)	**37**	30
Deferred storm damage costs(9)	**43**	38
Deferred transmission operating costs(10)	**75**	77
Derivatives (11)	**105**	125
Other(12)	**131**	137
Regulatory assets - noncurrent	**3,269**	3,294
Total regulatory assets	**$ 4,011**	$ 3,653
Regulatory liabilities:		
Monetization of guaranty settlement(13)	**$ 67**	$ 67
Income taxes refundable through future rates(14)	**33**	40
Reserve for refunds to electric utility customers(15)	**100**	113
Derivatives(11)	**43**	18
Other	**6**	5
Regulatory liabilities - current	**249**	243
Monetization of guaranty settlement(13)	**702**	831
Income taxes refundable through future rates(14)	**842**	872
Asset removal costs(16)	**581**	553
Reserve for refunds to electric utility customers(15)	**325**	425
Derivatives(11)	**276**	131
Other	**14**	76
Regulatory liabilities - noncurrent	**2,740**	2,888
Total regulatory liabilities	**$ 2,989**	$ 3,131

(1) Reflects expenditures associated with the NND Project, which pursuant to the SCANA Merger Approval Order, will be recovered from electric service customers over a 20-year period ending in 2039.

(2) Employee benefit plan costs have historically been recovered as they have been recorded under GAAP. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to FERC guidance, and costs deferred pursuant to specific South Carolina Commission regulatory orders. DESC expects to recover deferred pension costs through utility rates over periods through 2044. DESC expects to recover other deferred benefit costs through utility rates, primarily over average service periods of participating employees up to 11 years.

(3) Represents the carrying value of coal-fired generating units, including related materials and supplies inventory, retired from service prior to being fully depreciated. DESC is amortizing these amounts through cost of service rates following depreciation amounts that were designed to recover the retired units cost over their previous estimated remaining useful lives, which has been estimated to be through 2025. Based on current projections of remaining decommissioning costs, projected recovery is expected to extend through 2029. In addition, amounts include unrecovered costs of existing meters and equipment retired from service prior to being fully depreciated as part of the Advanced Metering Infrastructure project, which are being recovered through rates through 2028. This amount also includes certain inventory and preliminary survey and investigation charges being amortized over five years related to the transition or conversion from coal to gas fired generation at certain facilities. In addition, reflects an increase of approximately $7 million related to the abandonment of certain peaking gas generation facilities, such amounts having been reclassified from property, plant and equipment to noncurrent other unrecovered plant. Unamortized amounts are included in rate base and are earning a current return.

(4) Represents deferred costs associated with electric demand reduction programs, and such deferred costs are currently being recovered over three years through an approved rate rider.

(5) Represents amounts under- or over-collected from customers pursuant to the cost of fuel components approved by the South Carolina Commission..

(6) Represents deferred depreciation and accretion expense related to legal obligations associated with the future retirement of generation, transmission and distribution properties. The AROs primarily relate to DESC's electric generating facilities, including Summer, and are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 105 years.

(7) Represents the changes in fair value and payments made or received upon settlement of certain interest rate derivatives designated as cash flow hedges. The amounts recorded are expected to be amortized to interest expense over the lives of the underlying debt through 2065.

(8) Reflects amounts associated with the assessment and clean-up of sites currently or formerly owned by DESC. Such remediation costs are expected to be recovered over periods of up to 27 years. See Note 12 for additional information.

(9) Represents storm restoration costs for which DESC expects to receive future recovery through customer rates over approximately 10 years pursuant to the settlement agreement approved in DESC's retail electric base rate case. Unamortized amounts are included in rate base and are earning a current return.

(10) Includes deferred depreciation and property taxes associated with certain transmission assets for which DESC expects recovery from customers through future rates over approximately 42 years pursuant to the settlement agreement approved in DESC's retail electric base rate case. Unamortized amounts are included in rate base and earning a current return. See Note 12 for additional information.

(11) Represents changes in the fair value of derivatives, excluding separately presented interest rate hedges, that following settlement are expected to be recovered from or refunded to customers.

(12) Various other regulatory assets are expected to be recovered through rates over varying periods through 2047.

(13) Represents proceeds related to the monetization of the Toshiba Settlement. In accordance with the SCANA Merger Approval Order, this balance, net of amounts that may be required to satisfy liens, will be refunded to electric customers over a 20-year period ending in 2039.

(14) Includes (i) excess deferred income taxes arising from the remeasurement of deferred income taxes in connection with the enactment of the 2017 Tax Reform Act (certain of which are protected under normalization rules and will be amortized over the remaining lives of related property, and certain of which will be amortized to the benefit of customers over prescribed periods as instructed by regulators) and (ii) deferred income taxes arising from investment tax credits, offset by (iii) deferred income taxes that arise from utility operations that have not been included in customer rates (a portion of which relate to depreciation and are expected to be recovered over the remaining lives of the related property which may range up to 85 years). See Note 7 for additional information.

(15) Reflects amounts previously collected from retail electric customers of DESC for the NND Project to be credited to customers over an estimated 11-year period effective February 2019 in connection with the SCANA Merger Approval Order.

(16) Represents estimated net collections through depreciation rates of amounts to be expended for the removal of assets in the future.

Regulatory assets have been recorded based on the probability of their recovery. All regulatory assets represent incurred costs that may be deferred under GAAP for regulated operations. The South Carolina Commission or the FERC has reviewed and approved through specific orders certain of the items shown as regulatory assets. In addition, regulatory assets include, but are not limited to, certain costs which have not been specifically approved for recovery by one of these regulatory agencies. While such costs are not currently being recovered, management believes that they would be allowable under existing rate-making concepts embodied in rate orders or applicable state law and expects to recover these costs through rates in future periods.

4. OPERATING REVENUE

DESC's operating revenue consists of the following:

Year Ended December 31,	2022		2021		2020	
(millions)	Electric	Gas	Electric	Gas	Electric	Gas
Customer class:						
Residential	**$ 1,375**	**$ 303**	$ 1,211	$ 245	$ 1,127	$ 201
Commercial	**968**	**184**	834	133	746	103
Industrial	**533**	**166**	424	103	341	65
Other	**203**	**23**	157	25	123	18
Revenues from contracts with customers	**3,079**	**676**	2,626	506	2,337	387
Other revenues	**27**	**1**	13	1	15	—
Total Operating Revenues	**$ 3,106**	**$ 677**	$ 2,639	$ 507	$ 2,352	$ 387

Contract liabilities represent the obligation to transfer goods or services to a customer for which consideration has already been received from the customer. DESC had contract liability balances of $12 million and $8 million at December 31, 2022 and 2021, respectively. For the years ended December 31, 2022 and 2021, DESC recognized revenue of $6 million and $4 million, respectively, from the beginning contract liability balances as DESC fulfilled its obligations to provide service to its customers. Contract liabilities are recorded in customer deposits and customer prepayments in the Consolidated Balance Sheets.

Contract Costs

In limited instances, DESC provides economic development grants intended to support economic growth within DESC's electric service territory and defers such grants as regulatory assets on the Consolidated Balance Sheets. Whenever these grants are contingent on a customer entering into a long-term electric supply contract with DESC such costs are deferred and amortized on a straight-line basis over the term of the related service contract, which generally ranges from ten to 15 years.

Balances and activity related to contract costs deferred as regulatory assets were as follows:

	Regulatory Assets	
(millions)	**2022**	2021
Beginning balance, January 1	$ **11**	$ 12
Amortization	**(2)**	(1)
Ending balance, December 31	$ **9**	$ 11

5. EQUITY

For all periods presented, DESC's authorized shares of common stock, no par value, were 50 million, of which 40.3 million were issued and outstanding, and DESC's authorized shares of preferred stock, no par value, were 20 million, of which 1,000 shares were issued and outstanding. All outstanding shares of common and preferred stock are held by SCANA.

In 2022, Dominion Energy issued $72 million of shares of Dominion Energy common stock to partially satisfy DESC's remaining obligation under a settlement agreement with the SCDOR discussed in Note 12. In connection with this transaction, DESC recorded an equity contribution from Dominion Energy.

In 2021, Dominion Energy issued $104 million of shares of Dominion Energy common stock to satisfy DESC's obligation under a settlement agreement for the FILOT litigation discussed in Note 12. Additionally, in 2021, Dominion Energy issued $45 million of shares of Dominion Energy common stock to satisfy DESC's obligation for the initial payment under a settlement agreement with the SCDOR discussed in Note 12. In connection with these transactions, DESC recorded equity contributions from Dominion Energy.

In 2021, DESC returned $150 million of capital previously contributed from SCANA which had been funded by Dominion Energy.
In 2020, Dominion Energy issued $322 million of shares of Dominion Energy common stock in accordance with the settlement agreement associated with the Santee Cooper Ratepayer Case, as discussed in Note 12. In connection with this transaction, DESC recorded an equity contribution from Dominion Energy.

DESC's bond indenture under which it issues first mortgage bonds contains provisions that could limit the payment of cash dividends on its common stock. DESC's bond indenture permits the payment of dividends on DESC's common stock only either (1) out of its Surplus (as defined in the bond indenture) or (2) in case there is no Surplus, out of its net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. In addition, pursuant to the SCANA Merger Approval Order, the amount of any DESC dividends paid must be reasonable and consistent with the long-term payout ratio of the electric utility industry and gas distribution industry.

At December 31, 2022, DESC's retained earnings exceed the balance established by the Federal Power Act as a reserve on earnings attributable to hydroelectric generation plants. As a result, DESC is permitted to pay dividends without additional regulatory approval provided that such amounts would not bring the retained earnings balance below the established threshold.

6. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted-average coupon rates and maturities at December 31, 2022 and 2021 is as follows:

At December 31,	**2022 Weighted-average Coupon(1)**	**2022**	2021
(millions, except percentages)			
DESC:			
First Mortgage Bonds, 2.30% to 6.625%, due 2028 to 2065	**5.09 %**	$ **3,634**	$ 3,634
Tax-Exempt Financings:(2)			
Variable rate due 2038	**3.70 %**	**35**	35
3.625% and 4.00%, due 2028 and 2033	**3.90 %**	**54**	54
Other	**3.63 %**	**1**	1
Total principal		**3,724**	3,724
Securities due within one year		**—**	—
Unamortized discount, premium and debt issuance costs, net		**(32)**	(33)
Finance leases		**6**	10
Total long-term debt		$ **3,698**	$ 3,701

(1) Represents weighted-average coupon rates for debt outstanding as of December 31, 2022.
(2) Industrial revenue bonds totaling $68 million are secured by letters of credit that expire, subject to renewal, in the fourth quarter of 2023.

Based on stated maturity dates rather than early redemption dates that could be elected by instrument holders, the scheduled principal payments of long-term debt at December 31, 2022, were as follows:

(millions, except percentages)	2023	2024	2025	2026	2027	Thereafter	Total
First Mortgage Bonds	$ —	$ —	$ —	$ —	$ —	$ **3,634**	$ **3,634**
Tax-Exempt Financings	—	—	—	—	—	**89**	**89**
Other	—	—	—	—	—	**1**	**1**
Total	$ —	$ —	$ —	$ —	$ —	$ **3,724**	$ **3,724**
Weighted-average coupon						**5.06 %**	

Substantially all of DESC's electric utility plant is pledged as collateral in connection with long-term debt.

DESC is subject to a bond indenture dated April 1, 1993 (Mortgage) covering substantially all of its electric properties under which all of its first mortgage bonds (Bonds) have been issued. Bonds may be issued under the Mortgage in an aggregate principal amount not
exceeding the sum of (1) 70% of Unfunded Net Property Additions (as therein defined), (2) the aggregate principal amount of retired Bonds and (3) cash deposited with the trustee. Bonds, other than certain Bonds issued on the basis of retired Bonds, may be issued under the Mortgage only if Adjusted Net Earnings (as therein defined) for 12 consecutive months out of the 18 months immediately preceding the month of issuance are at least twice the annual interest requirements on all outstanding Bonds and Bonds to be issued (Bond Ratio). For the year ended December 31, 2022, the Bond Ratio was approximately 7.

Short-Term Debt

DESC's short-term financing is supported through its access as co-borrower to Dominion Energy's $6.0 billion joint revolving credit facility, which can be used for working capital, as support for the combined commercial paper programs of DESC, Dominion Energy, Virginia Power and Questar Gas, and for other general corporate purposes.

DESC's share of commercial paper and letters of credit outstanding under its joint credit facility with Dominion Energy, were as follows:

(millions)	**Facility Limit**	**Outstanding Commercial Paper**	**Outstanding Letters of Credit**
At December 31, 2022			
Joint revolving credit facility(1)	$ **1,000**	$ **249**	$ **—**
At December 31, 2021			
Joint revolving credit facility(1)	$ **1,000**	$ —	$ —

(1) The weighted-average interest rate of the outstanding commercial paper supported by the credit facility was 4.76% at December 31 2022.
(2) A maximum of $1.0 billion of the facility is available to DESC, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion Energy, Virginia Power and Questar Gas. A sub-limit for DESC is set within the facility limit but can be changed at the option of the co-borrowers multiple times per year. At December 31, 2022, the sub-limit for DESC was $500 million. If DESC has liquidity needs in excess of its sub-limit, the sub-limit

(2) A maximum of $1.0 billion of the facility is available to DESC, assuming adequate capacity is available after giving effect to uses by co-borrowers Dominion Energy, Virginia Power and Questar Gas. A sub-limit for DESC is set within the facility limit but can be changed at the option of the co-borrowers multiple times per year. At December 31, 2022, the sub-limit for DESC was $500 million. If DESC has liquidity needs in excess of its sub-limit, the sub-limit may be changed or such needs may be satisfied through short-term borrowings from DESC's parent or from Dominion Energy. This credit facility matures in June 2026, with the potential to be extended by the borrowers to June 2028. The credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.0 billion (or the sub-limit, whichever is less) of letters of credit.

In January 2021, DESC applied to FERC for a two-year renewal of its short-term borrowing authorization. On March 9, 2021, in Docket No. ES21-25-000, FERC granted DESC's request for a two-year renewal of its short-term borrowing authorization beginning on March 25, 2021. In January 2023, DESC applied to FERC for a two-year renewal of its short-term borrowing authorization. On March 15, 2023, in Docket No. ES23-26-000, FERC granted DESC's request for a two-year renewal of its short-term borrowing authorization beginning on March 25, 2023. DESC may issue short-term debt in amounts not to exceed $2.2 billion outstanding.

DESC is obligated with respect to an aggregate of $68 million of industrial revenue bonds which are secured by letters of credit. These letters of credit expire, subject to renewal, in the fourth quarter of 2023.

DESC has FERC approval to enter into an inter-company credit agreement with Dominion Energy under which DESC may have short-term borrowings outstanding up to $900 million. At December 31, 2022 and 2021, DESC had borrowings outstanding under this credit agreement totaling $769 million and $415 million, respectively, which are recorded in affiliated and related party payables in DESC's Consolidated Balance Sheets. For the years ended December 31, 2022, 2021 and 2020, DESC recorded interest charges of $19 million, less than $1 million and $7 million, respectively.

Fuel Company and GENCO participated in a SCANA utility money pool until January 2021, when that utility money pool was closed. Money pool borrowings and investments bore interest at short-term market rates. For the years ended December 31, 2021 and 2020, DESC recorded interest income from money pool transactions of less than $1 million and $2 million, respectively, and for the same periods DESC recorded interest expense from money pool transactions of less than $1 million and $2 million, respectively.

7. INCOME TAXES

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws involves uncertainty, since tax authorities may interpret the laws differently. DESC is routinely audited by federal and state tax authorities. Ultimate resolution of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

As indicated in Note 2, DESC's operations, including accounting for income taxes, are subject to regulatory accounting treatment. For regulated operations, many of the changes in deferred taxes represent amounts probable of collection from or refund to customers, and were recorded as either an increase to a regulatory asset or liability. See Note 3 for more information and current year developments.

Details of income tax expense for continuing operations including noncontrolling interests were as follows:

Year Ended December 31,		2022		2021		2020
(millions)						
Current:						
Federal	**$**	**(69)**	$	(42)	$	(139)
State		**—**		(43)		3
Total current benefit		**(69)**		(85)		(136)
Deferred:						
Federal						
Taxes before operating loss carryforwards, investment tax credits and tax reform		**132**		43		156
Tax utilization expense of operating loss carryforwards		**33**		34		33
State		**31**		17		16
Total deferred expense		**196**		94		205
Investment tax credit-amortization		**(1)**		(1)		(1)
Total income tax expense	**$**	**126**	$	8	$	68

Subsequent to the SCANA Combination, DESC's annual utilization of its net operating losses are restricted by the tax law. However, in certain circumstances, the utilization may be increased if SCANA recognizes built-in gains on certain sales of assets.

For continuing operations including noncontrolling interests, the statutory U.S. federal income tax rate reconciles to DESC's effective income tax rate as follows:

Year Ended December 31,	2022	2021	2020
U.S. statutory rate	**21 %**	21 %	21 %
Increases (reductions) resulting from:			
State taxes, net of federal benefit	**4.7**	5.7	3.9
AFUDC - equity	**—**	(0.4)	—
Amortization of federal investment tax credits	**(0.2)**	(0.6)	(0.4)
Reversal of excess deferred income taxes	**(4.7)**	(8.6)	(6.0)
Changes in unrecognized tax benefits	**—**	(15.6)	—
Prior period adjustments	**—**	1.3	—
Other	**(0.2)**	0.8	0.5
Effective tax rate	**20.6 %**	3.6 %	19.0 %

In December 2021, unrecognized tax benefits related to several state uncertain tax positions were effectively settled through negotiations with the taxing authority. Management believed it was reasonably possible these unrecognized tax benefits could decrease through settlement negotiations or payments during 2021. However no income tax benefits could be recognized unless or until the positions were effectively settled. Resolution of these uncertain tax positions decreased income tax expense by $34 million.

DESC's deferred income taxes consist of the following:

At December 31,		2022		2021
(millions)				
Deferred income taxes:				
Total deferred income tax assets	**$**	**1,066**	$	1,191
Total deferred income tax liabilities		**2,170**		2,048
Total net deferred income tax liabilities	**$**	**1,104**	$	857
Total deferred income taxes:				
Depreciation method and plant basis differences	**$**	**1,095**	$	1,073
Excess deferred income taxes		**(212)**		(221)
Unrecovered nuclear plant cost		**479**		508
DESC rate refund		**(89)**		(113)
Toshiba settlement		**(162)**		(189)
Nuclear decommissioning		**(44)**		(54)
Deferred state income taxes		**259**		212
Federal benefit of deferred state income taxes		**(54)**		(45)
Deferred fuel, purchased energy and gas costs		**107**		27
Pension benefits		**50**		35
Other postretirement benefits		**(32)**		(35)
Loss and credit carryforwards		**(352)**		(373)
Other		**59**		32
Total net deferred income tax liabilities	**$**	**1,104**	$	857

Deferred Investment Tax Credits-Regulated Operations	**14**	15
Total Deferred Taxes and Deferred Investment Tax Credits	**$ 1,118**	$ 872

At December 31, 2022, DESC had the following deductible loss and credit carryforwards:

(millions)	Deductible Amount	Deferred Tax Asset	Expiration Period
Federal losses	**$ 731**	**$ 153**	**2037**
Federal production and other credits	**—**	**29**	**2035-2042**
State losses	**2,779**	**139**	**2037-2042**
State investment and other credits	**—**	**31**	**2026-2032**
Total	**$ 3,510**	**$ 352**	

A reconciliation of changes in DESC's unrecognized tax benefits follows:

(millions)	2022	2021
Balance at January 1	**$ 61**	$ 132
Increases-prior period positions	**6**	6
Decreases-prior period positions	**(1)**	(52)
Increases-current period positions	**1**	1
Settlements with tax authorities	**—**	(26)
Balance at December 31	**$ 67**	$ 61

Certain unrecognized tax benefits, or portions thereof, if recognized, would affect the effective tax rate. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations. If recognized, all the unrecognized tax benefits would impact the effective tax rate.

The statute is closed for IRS examination of years prior to 2013. The IRS is currently examining DESC's federal returns from 2013 through 2017. DESC is no longer subject to state and local income tax examinations by tax authorities for years prior to 2019.

It is reasonably possible that these unrecognized tax benefits may decrease by $39 million within the next twelve months. If such changes were to occur, other than revisions of the accrual for interest on tax underpayments and overpayments, earnings could increase by less than $26 million. Otherwise, with regard to 2022 and prior years, DESC cannot estimate the range of reasonably possible changes to unrecognized tax benefits that may occur in 2023.

DESC is also obligated to report adjustments resulting from IRS settlements to state tax authorities. In addition, if DESC utilizes operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

8. DERIVATIVE FINANCIAL INSTRUMENTS

See Note 2 for DESC's accounting policies, objectives, and strategies for using derivative instruments. See Notes 2 and 9 for further information about fair value measurements and associated valuation methods for derivatives.

Cash collateral is used in the table below to offset derivative assets and liabilities. Certain of DESC's derivative instruments contain credit-related contingent provisions. These provisions require DESC to provide collateral upon the occurrence of specific events, primarily a credit rating downgrade. If the credit-related contingent features underlying the instruments that are in a liability position and not fully collateralized with cash were fully triggered as of December 31, 2022 and 2021, DESC would have been required to post $0 and $7 million, respectively, of additional collateral to its counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. DESC had no collateral posted related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash at December 31, 2022 and 2021. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of December 31, 2022 and 2021 was $0 and $7 million, respectively, which does not include the impact of any offsetting asset positions.

The table below presents derivative balances by type of financial instrument, if the gross amounts recognized in the Consolidated Balance Sheets were netted with derivative instruments and cash collateral received or paid. DESC's commodity derivative assets are not subject to a master netting agreement or similar arrangement.

	December 31, 2022				December 31, 2021			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Gross Assets Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Received**	**Net Amounts**	Gross Assets Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Received	Net Amounts
Interest rate contracts:								
Over-the-counter	**$ 1**	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ —	$ —
Total derivatives	**$ 1**	**$ —**	**$ —**	**$ 1**	$ —	$ —	$ —	$ —

	December 31, 2022				December 31, 2021			
		Gross Amounts Not Offset in the Consolidated Balance Sheet				Gross Amounts Not Offset in the Consolidated Balance Sheet		
(millions)	**Gross Liabilities Presented in the Consolidated Balance Sheet**	**Financial Instruments**	**Cash Collateral Paid**	**Net Amounts**	Gross Liabilities Presented in the Consolidated Balance Sheet	Financial Instruments	Cash Collateral Paid	Net Amounts
Interest rate contracts:								
Over-the-counter	**$ —**	**$ —**	**$ —**	**$ —**	$ 7	$ —	$ —	$ 7
Total derivatives	**$ —**	**$ —**	**$ —**	**$ —**	$ 7	$ —	$ —	$ 7

Volumes

The following table presents the volume of derivative activity at December 31, 2022. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions.

(millions)	Current	Noncurrent
Electricity (MWh):		
Fixed price	**2**	**24**
Interest rate(1)	**$ —**	**$ 35**

(1) Maturity is determined based on final settlement period.

Fair Value and Gains and Losses on Derivative Instruments

The following table presents the fair values of derivatives and where they are presented in the Consolidated Balance Sheets:

Fair Value - Derivatives not under Hedge

(millions)	Accounting
At December 31, 2022	
Current Assets	
Commodity	**$ 41**
Total current derivative assets (1)	**41**
Noncurrent Assets	
Commodity	**210**
Interest rate	**1**
Total noncurrent derivative assets (2)	**211**
Total derivative assets	**$ 252**
At December 31, 2021	
Current Assets	
Commodity	$ 18
Total current derivative assets (1)	18
Noncurrent Assets	
Commodity	130
Total noncurrent derivative assets (2)	130
Total derivative assets	$ 148
Current Liabilities	
Interest rate	$ 1
Total current derivative liabilities(3)	1
Noncurrent Liabilities	
Interest rate	6
Total noncurrent derivative liabilities(4)	6
Total derivative liabilities	$ 7

(1) Current derivative assets are presented in other current assets in DESC's Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred debits and other assets in DESC's Consolidated Balance Sheets.
(3) Current derivative liabilities are presented in other current liabilities in DESC's Consolidated Balance Sheets.
(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in DESC's Consolidated Balance Sheets.

The following tables present the gains and losses on derivatives, as well as where the associated activity is presented in its Consolidated Balance Sheets and Statements of Comprehensive Income:

Derivatives in Cash Flow Hedging Relationships

(millions)	Increase (Decrease) in Derivatives Subject to Regulatory Treatment(1)
Year Ended December 31, 2022	
Derivative type and location of gains (losses):	
Interest rate	**$ 1**
Total	**$ 1**
Year Ended December 31, 2021	
Derivative type and location of gains (losses):	
Interest rate	$ 4
Total	$ 4
Year Ended December 31, 2020	
Derivative type and location of gains (losses):	
Interest rate	$ 6
Total	$ 6

(1) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/ liabilities have no associated effect in the Consolidated Statements of Comprehensive Income.

Derivatives Not designated as Hedging Instruments

(millions)	Amount of Gain (Loss) Recognized in Income on Derivatives(1)		
Year Ended December 31,	**2022**	2021	2020
Derivative type and location of gains (losses):			
Commodity contracts:			
Purchased power	**$ 77**	8	—
Interest rate contracts:			
Interest charges	**(2)**	(2)	(1)
Total	**$ 75**	$ 6	$ (1)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in the Consolidated Statements of Comprehensive Income.

9. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

DESC's fair value measurements are made in accordance with the policies discussed in Note 2. See Note 8 for additional information about DESC's derivative and hedge accounting activities.

Level 3 Valuations

DESC enters into physical forwards contracts, which are considered Level 3 as they have one or more inputs that are not observable and are significant to the valuation. The discounted cash flow method is used to value Level 3 physical forwards contracts. The discounted cash flow model for forwards calculates mark-to-market valuations based on forward market prices, original transaction prices, volumes, risk-free rate of return, and credit spreads. For Level 3 fair value measurements, certain forward market prices are considered unobservable.

The following table presents DESC's quantitative information about Level 3 fair value measurements at December 31, 2022. The range and weighted average are presented in dollars for market price inputs.

	Fair Value (millions)		Valuation Techniques	Unobservable Input	Range	Weighted Average(1)
Assets						
Physical forwards:						
Electricity	$	251	Discounted cash flow	Market price (per MWh)(2)	27-110	51
Total assets	$	251				

(1) Averages weighted by volume.
(2) Represents market prices beyond defined terms for Levels 1 and 2.

Sensitivity of the fair value measurements to changes in the significant unobservable inputs is as follows:

Significant Unobservable Inputs	Position	Change to Input	Impact on Fair Value Measurement
Market price	Buy	Increase (decrease)	Gain (loss)
Market price	Sell	Increase (decrease)	Loss (gain)

Nonrecurring Fair Value Measurement

During the third quarter of 2020, DESC determined that certain of its nonutility property was impaired and recorded a $12 million charge ($9 million after tax) within impairments and other charges in its Consolidated Statements of Comprehensive Income (reflected in the Corporate and Other Segment) to adjust the property down to its estimated fair value of $6 million. The fair value determinations are considered Level 2 fair value measurements due to the use of real estate appraised values.

Recurring Fair Value Measurements

Fair value disclosures for assets held in DESC's pension plan are presented in Note 11.
The following table presents DESC's assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

	Level 1		Level 2		Level 3		Total	
(millions)								
At December 31, 2022								
Assets								
Commodity	$	—	$	—	$	251	$	251
Interest rate		—		1		—		1
Total assets	$	—	$	1	$	251	$	252
At December 31, 2021								
Assets								
Commodity	$	—	$	—	$	148	$	148
Total assets	$	—	$	—	$	148	$	148
Liabilities								
Interest rate	$	—	$	7	$	—	$	7
Total liabilities	$	—	$	7	$	—	$	7

The following table presents the net change in DESC's assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category. There were no net changes in assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the year ended December 31, 2020.

	2022		2021	
(millions)				
Balance at January 1,	$	148	$	—
Total realized and unrealized gains (losses):				
Included in earnings:				
Purchased power		77		8
Included in regulatory assets/liabilities		103		148
Settlements		(77)		(8)
Balance at December 31,	$	251	$	148

There are no unrealized gains and losses included in earnings in the Level 3 fair value category related to assets/liabilities still held at the reporting date for the years ended December 31, 2022 and 2021.

Fair Value of Financial Instruments

Substantially all of DESC's financial instruments are recorded at fair value, with the exception of the instruments described below, which are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. The carrying amount of financial instruments classified within current assets and current liabilities are representative of fair value because of the short-term nature of these instruments. For financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

At December 31,	2022				2021			
(millions)	Carrying Amount		Estimated Fair Value(1)		Carrying Amount		Estimated Fair Value(1)	
Long-term debt(2)	$	3,691	$	3,581	$	3,691	$	4,798

(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. All fair value measurements are classified as Level 2. The carrying amount of debt issuances with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.
(2) Carrying amount includes current portions included in securities due within one year and amounts which represent the unamortized debt issuance costs and discount or premium.

10. ASSET RETIREMENT OBLIGATIONS

A liability for the present value of an ARO is recognized when incurred if the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to DESC's regulated utility operations. As of December 31, 2022 and 2021, DESC has recorded AROs of $299 million and $287 million, respectively, for nuclear plant decommissioning. In addition, DESC has recorded AROs of $313 million and $312 million at December 31, 2022 and 2021, respectively, for other conditional obligations primarily related to other generation and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of precision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of AROs is as follows:

(millions)	2022		2021	
Beginning balance	$	583	$	582
Liabilities incurred		6		—
Liabilities settled		(1)		—
Accretion expense		25		24
Revisions in estimated cash flows(1)		—		(23)
Other		(1)		—

Ending balance	$ 612	$ 583

(1) The decrease in 2021 is due to the remeasurement of gas pipeline AROs.

11. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCANA sponsors a noncontributory defined benefit pension plan covering regular, full-time employees hired before January 1, 2014. DESC participates in SCANA's pension plan. SCANA's policy has been to fund the plan as permitted by applicable federal income tax regulations, as determined by an independent actuary.

The pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and all eligible employees hired subsequently. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee's average annual base earnings received during the last three years of employment. Benefits under the cash balance formula continued to accrue through December 31, 2020, after which no benefits accrue except for those participants under the cash balance formula who continue to earn interest credits. Benefits under the final average pay formula will continue to accrue through December 31, 2023, after which date no benefits will be accrued. Once the benefits under SCANA's pension plan no longer accrue, eligible participants will accrue benefits under a cash balance formula within the Dominion Energy Pension Plan, a qualified defined benefit pension plan sponsored by Dominion Energy.

In addition to pension benefits, SCANA provides certain unfunded postretirement health care and life insurance benefits to certain active and retired employees. DESC participates in these programs. Retirees hired before January 1, 2011 share in a portion of their medical care cost, while employees hired subsequently are responsible for the full cost of retiree medical benefits elected by them. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

The same benefit formula applies to all SCANA subsidiaries participating in the parent sponsored plans and, with regard to the pension plan, there are no legally separate asset pools. The postretirement benefit plans are accounted for as multiple employer plans.

Changes in Benefit Obligations
The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for pension benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
(millions)	**2022**	2021	**2022**	2021
Benefit obligation, January 1	**$ 702**	$ 742	**$ 171**	$ 184
Service cost	**8**	9	**1**	1
Actuarial (gain) loss	**21**	20	**6**	6
Benefits paid	**(105)**	(28)	**(44)**	(8)
Amounts funded to parent	**(46)**	(41)	**(13)**	(12)
Benefit obligation, December 31	**$ 580**	$ 702	**$ 121**	$ 171

The accumulated benefit obligation for pension benefits for DESC was $578 million and $697 million at December 31, 2022 and 2021, respectively. The accumulated pension benefit obligation differs from the projected pension benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2022	2021	**2022**	2021
Annual discount rate used to determine benefit obligation	**5.69 %**	3.06 %	**5.70 %**	3.11 %
Assumed annual rate of future salary increases for projected benefit obligation	**3.93 %**	3.71 %	**N/A**	N/A
Crediting interest rate for cash balance plans	**4.44 %**	1.81 %	**N/A**	N/A

DESC's pension benefit obligations include a gain of $105 million in 2022 resulting primarily from an increase in the discount rate and a gain of $29 million in 2021 resulting primarily from an increase in the discount rate and a completed experience study. Actuarial gains recognized in DESC's other postretirement benefit obligations include a $44 million gain in 2022 and a $8 million gain in 2021 resulting from an increase in the discount rate.

A 6.25% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2022. The rate was assumed to decrease gradually to 5.0% in 2026 and to remain at that level thereafter.

Funded Status

	Pension Benefits		Other Postretirement Benefits	
At December 31,	**2022**	2021	**2022**	2021
(millions)				
Fair value of plan assets	**$ 561**	$ 768	**$ —**	$ —
Benefit obligation	**580**	702	**121**	171
Funded status	**$ (19)**	$ 66	**$ (121)**	$ (171)

Amounts recognized on the consolidated balance sheets were as follows:

	Pension Benefits		Other Postretirement Benefits	
At December 31,	**2022**	2021	**2022**	2021
(millions)				
Noncurrent assets	**$ —**	$ 66	**$ —**	$ —
Current liability	**—**	—	**(11)**	(10)
Noncurrent liability	**(19)**	—	**(110)**	(161)

Amounts recognized in AOCI were as follows:

	Pension Benefits		Other Postretirement Benefits	
At December 31,	**2022**	2021	**2022**	2021
(millions)				
Net actuarial (gain) loss	**$ 3**	$ 1	**$ (1)**	$ —

Amounts recognized in regulatory assets were as follows:

	Pension Benefits		Other Postretirement Benefits	
At December 31,	**2022**	2021	**2022**	2021
(millions)				
Net actuarial (gain) loss	**$ 164**	$ 70	**$ (46)**	$ (5)

In connection with the joint ownership of Summer, costs related to pensions attributable to Santee Cooper as of both December 31, 2022 and 2021 totaled $21 million and $14 million and were recorded within deferred debits. Costs related to other postretirement benefits attributable to Santee Cooper as of December 31, 2022 and 2021 totaled $9 million and $12 million were recorded within deferred debits.

Changes in Fair Value of Plan Assets

(millions)	Pension Benefits 2022	2021
Beginning Balance	**$ 768**	$ 747
Actual return (loss) on plan assets	**(161)**	62
Benefits paid	**(46)**	(41)
Ending Balance	**$ 561**	$ 768

Investment Policies and Strategies

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

DESC's overall objective for investing its pension plan assets is to achieve appropriate long-term rates of return commensurate with prudent levels of risk. To minimize risk, funds are diversified among asset classes, securities, active and passive investment strategies and investment advisors. The strategic target asset allocations for DESC's pension fund is: 45% global equities, 53% fixed income and 2% cash. Global equities include investments in U.S. and non-U.S. companies, developed and emerging markets and small and large cap companies. The split between U.S. and non-U.S. companies is roughly 60% U.S./40% Non-U.S. Fixed income includes corporate debt instruments of companies from diversified industries and U.S. Treasuries. Equity and fixed income investments are in individual securities as well as mutual funds.

DESC also utilizes common/collective trust funds as an investment vehicle for its defined benefit plans. A common/collective trust fund is a pooled fund operated by a bank or trust company for investment of the assets of various organizations and individuals in a well-diversified portfolio. Common/collective trust funds are funds of grouped assets that follow various investment strategies.

For 2023, the expected long-term rate of return on assets will be 7.00%. DESC determines the expected long-term rates of return on plan assets for its pension plans by using a combination of:

- Expected inflation and risk-free interest rate assumptions;
- Historical return analysis to determine long term historic returns as well as historic risk premiums for various asset classes;
- Expected future risk premiums, asset classes' volatilities and correlations;
- Forward-looking return expectations derived from the yield on long-term bonds and the expected long-term returns of major capital market assumptions; and
- Investment allocation of plan assets.

Fair Value Measurements

Assets held by the pension plan are measured at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2022 and 2021, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

At December 31,	2022				2021			
(millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	**$ —**	**$ 2**	**$ —**	**$ 2**	$ —	$ 1	$ —	$ 1
Corporate debt instruments	**—**	**137**	**—**	**137**	—	332	—	332
Government and other debt instruments	**—**	**18**	**—**	**18**	—	67	—	67
Total recorded at fair value	**$ —**	**$ 157**	**$ —**	**$ 157**	$ —	$ 400	$ —	$ 400
Assets recorded at NAV(1)								
Common/collective trust funds				**417**				387
Total recorded at NAV				**$ 417**				$ 387
Total investments(2)				**$ 574**				$ 787

(1) These investments that are measured at fair value using the NAV per share (or its equivalent) as a practical expedient are not required to be categorized in the fair value hierarchy.

(2)Excludes net assets related to pending sales of securities of $1 million, net accrued income of $1 million, and includes net assets related to pending purchases of securities of $15 million at December 31, 2022. Excludes net assets related to pending sales of securities of $4 million, net accrued income of $2 million, and includes net assets related to pending purchases of securities of $25 million at December 31, 2021.

For purposes of calculating NAV, portfolio securities and other assets for which market quotes are readily available are valued at market value. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. U.S. Treasury securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt instruments and government and other debt instruments are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. In addition, corporate debt instruments include investments in open-end mutual funds registered with the SEC that invest in corporate debt instruments. Common collective trust assets are valued at NAV, which has been determined based on the unit values of the trust funds. Unit values are determined by the organization sponsoring such trust funds by dividing the trust funds' net assets at fair value by the units outstanding at each valuation date.

Expected Cash Flows

Total benefits expected to be paid from the pension plan or company assets for the other postretirement benefits plan (net of participant contributions), respectively, are as follows:
Expected Benefit Payments

(millions)	Pension Benefits	Other Postretirement Benefits
2023	**$ 45**	**$ 11**
2024	**47**	**11**
2025	**47**	**11**
2026	**46**	**11**
2027	**45**	**11**
2028-2032	**243**	**57**

Pension Plan Contributions

Under its funding policies, DESC evaluates plan funding requirements annually, usually in the fourth quarter after receiving updated plan information from its actuary. Based on the funded status of each plan and other factors, DESC determines the amount of contributions for the current year, if any, at that time. DESC made no contributions to the pension trust in 2022, 2021 or 2020. DESC does not expect to contribute to its qualified pension plan in 2023.

Net Periodic Benefit Cost

Net periodic benefit cost is recorded utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit (Credit) Cost

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	2022	2021	2020	2022	2021	2020
(millions)						
Service cost	**$ 8**	$ 9	$ 12	**$ 1**	$ 1	$ 3
Interest cost	**21**	20	24	**6**	6	8
Expected return on assets	**(49)**	(48)	(45)	**—**	—	—
Amortization of actuarial losses	**1**	6	6	**—**	—	—

	Pension 2022	Pension 2021	Pension 2020	OPEB 2022	OPEB 2021	OPEB 2020
Settlement loss	—	—	7	—	—	—
Net periodic benefit cost	$ (19)	$ (13)	$ 4	$ 7	$ 7	$ 11

In connection with regulatory orders, DESC recovers current pension costs through a rate rider that may be adjusted annually for retail electric operations or through cost of service rates for gas operations. For retail electric operations, current pension expense is recognized based on amounts collected through a rate rider, and differences between actual pension expense and amounts recognized pursuant to the rider are deferred as a regulatory asset (for under-collections) or regulatory liability (for over-collections) as applicable. In addition, DESC amortizes certain previously deferred pension costs. See Note 3.

Other changes in plan assets and benefit obligations recognized in other comprehensive income (net of tax) were as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2022**	2021	2020	**2022**	2021	2020
(millions)						
Current year actuarial (gain) loss	**$ 2**	$ (3)	$ 2	**$ (1)**	$ —	$ (2)
Total recognized in other comprehensive income	**$ 2**	$ (3)	$ 2	**$ (1)**	$ —	$ (2)

Other changes in plan assets and benefit obligations recognized in regulatory assets were as follows:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2022**	2021	2020	**2022**	2021	2020
(millions)						
Current year actuarial (gain) loss	**$ 95**	$ (39)	$ 1	**$ (41)**	$ (6)	$ (27)
Amortization of actuarial losses	**(1)**	(5)	(6)	**—**	—	(1)
Settlement loss	**—**	—	(6)	**—**	—	—
Total recognized in regulatory assets	**$ 94**	$ (44)	$ (11)	**$ (41)**	$ (6)	$ (28)

Significant assumptions used in determining net periodic benefit cost:

	Pension Benefits			Other Postretirement Benefits		
Year Ended December 31,	**2022**	2021	2020	**2022**	2021	2020
Discount rate	**3.06 %**	2.73 %	3.47 %	**3.11 %**	2.80 %	2.80 %
Expected return on plan assets	**7.00 %**	7.00 %	7.00 %	**n/a**	n/a	n/a
Rate of compensation increase	**3.71 %**	4.52 %	3.00 %	**n/a**	n/a	n/a
Crediting interest rate for cash balance plans	**1.81 %**	1.93 %	2.67 %	**n/a**	n/a	n/a
Health care cost trend rate				**6.25 %**	6.25 %	6.25 %
Ultimate health care cost trend rate				**5.00 %**	5.00 %	5.00 %
Year achieved				**2026-2027**	2025-2026	2025-2026

Participation in Dominion Energy Defined Benefit Plans

As discussed above, effective January 2021, DESC employees who had been receiving a cash balance formula became covered by the Dominion Energy Pension Plan. In addition, DESC employees hired in 2021 prior to July 2021 are covered by the Dominion Energy Pension Plan. As a participating employer, DESC is subject to Dominion Energy's funding policy, which is to contribute annually an amount that is in accordance with ERISA. DESC made contributions of less than $1 million to the Dominion Energy Pension Plan during 2022 and DESC made no contributions to the Dominion Energy Pension Plan during 2021. DESC's net periodic pension cost related to this plan was $1 million and $3 million in 2022 and 2021, respectively. Net periodic benefit (credit) cost is reflected in other operations and maintenance expense in DESC's Consolidated Statements of Income. The funded status of various Dominion Energy subsidiary groups and employee compensation are the basis for determining the share of total pension costs for participating Dominion Energy subsidiaries. During 2022 and 2021, DESC's pension and other postretirement benefits obligation includes $4 million and $3 million, respectively, for amounts due to Dominion Energy related to this plan.

Dominion Energy holds investments in trusts to fund employee benefit payments for the pension plan in which DESC's employees participate. Any investment-related declines in these trusts will result in future increases in the net periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that DESC will provide to Dominion Energy for its share of employee benefit plan contributions.

401(k) Retirement Savings Plan

Effective January 2021, DESC participates in a defined contribution savings plan sponsored by Dominion Energy. Previously, DESC had participated in a defined contribution plan sponsored by SCANA, which was merged into the Dominion Energy plan in December 2020. DESC recognized employer matching contributions of $13 million, $11 million, and $14 million in 2022, 2021, and 2020, respectively.

12. COMMITMENTS AND CONTINGENCIES

As a result of issues generated in the ordinary course of business, DESC is involved in legal proceedings before various courts and is periodically subject to governmental examinations (including by regulatory authorities), inquiries and investigations. Certain legal proceedings and governmental examinations involve demands for unspecified amounts of damages, are in an initial procedural phase, involve uncertainty as to the outcome of pending appeals or motions, or involve significant factual issues that need to be resolved, such that
it is not possible for DESC to estimate a range of possible loss. For such matters that DESC cannot estimate, a statement to this effect is made in the description of the matter. Other matters may have progressed sufficiently through the litigation or investigative processes such that DESC is able to estimate a range of possible loss. For legal proceedings and governmental examinations that DESC is able to reasonably estimate a range of possible losses, an estimated range of possible loss is provided, in excess of the accrued liability (if any) for such matters. DESC maintains various insurance programs, including general liability insurance coverage which provides coverage for personal injury or wrongful death cases. Any accrued liability is recorded on a gross basis with a receivable also recorded for any probable insurance recoveries. Estimated ranges of loss are inclusive of legal fees and net of any anticipated insurance recoveries. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent DESC's maximum possible loss exposure. The circumstances of such legal proceedings and governmental examinations will change from time to time and actual results may vary significantly from the current estimate. For current proceedings not specifically reported below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on DESC's financial position, liquidity or results of operations.

Environmental Matters

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

From a regulatory perspective, DESC continually monitors and evaluates its current and projected emission levels and strives to comply with all state and federal regulations regarding those emissions. DESC participates in the SO_2 and NO_X emission allowance programs with respect to coal plant emissions and also has constructed additional pollution control equipment at its coal-fired electric generating plants. These actions are expected to address many of the rules and regulations discussed herein.

Air

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

ACE Rule

In July 2019, the EPA published the final rule informally referred to as the ACE Rule, as a replacement for the Clean Power Plan. The ACE Rule regulated GHG emissions from existing coal-fired power plants pursuant to Section 111(d) of the CAA and required states to develop plans by July 2022 establishing unit-specific performance standards for existing coal-fired power plants. In January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE Rule and remanded it to the EPA. This decision would take effect upon issuance of the court's mandate. In March 2021, the court issued a partial mandate vacating and remanding all parts of the ACE Rule except for the portion of the ACE Rule that repealed the Clean Power Plan. In October 2021, the U.S. Supreme Court agreed to hear a challenge of the U.S. Court of Appeals for the D.C. Circuit's decision on the ACE Rule. In June 2022, the U.S. Supreme Court reversed the D.C. Circuit's decision on the ACE Rule and remanded the case back to the D.C. Circuit. Until the case is resolved by the D.C. Circuit and/or the EPA issues new rulemaking, DESC cannot predict an impact to its operations, financial condition and/or cash flows.

Carbon Regulations

In August 2016, the EPA issued a draft rule proposing to reaffirm that a source's obligation to obtain a PSD or Title V permit for GHGs is triggered only if such permitting requirements are first triggered by non-GHG, or conventional, pollutants that are regulated by the New Source Review program, and exceed a significant emissions rate of 75,000 tons per year of CO2 equivalent emissions. Until the EPA ultimately takes final action on this rulemaking, DESC cannot predict the impact to its results of operations, financial condition and/or cash flows.

In December 2018, the EPA proposed revised Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources. The proposed rule would amend the previous determination that the best system of emission reduction for newly constructed coal-fired steam generating units is no longer partial carbon capture and storage. Instead, the proposed revised best system of emission reduction for this source category is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with best operating practices. The proposed revision to the performance standards for coal-fired steam generating units remains pending. Until the EPA ultimately takes final action on this rulemaking, DESC cannot predict the impact to its results of operations, financial condition and/or cash flows.

Water

The CWA, as amended, is a comprehensive program requiring a broad range of regulatory tools including a permit program to authorize and regulate discharges to surface waters with strong enforcement mechanisms. DESC must comply with applicable aspects of the CWA programs at its operating facilities.

Regulation 316(b)

In October 2014, the final regulations under Section 316(b) of the CWA that govern existing facilities and new units at existing facilities that employ a cooling water intake structure and that have flow levels exceeding a minimum threshold became effective. The rule establishes a national standard for impingement based on seven compliance options, but forgoes the creation of a single technology standard for entrainment. Instead, the EPA has delegated entrainment technology decisions to state regulators. State regulators are to make case-by-case entrainment technology determinations after an examination of five mandatory facility-specific factors, including a social cost-benefit test, and six optional facility-specific factors. The rule governs all electric generating stations with water withdrawals above two MGD, with a heightened entrainment analysis for those facilities over 125 MGD. DESC has four facilities that are subject to the final regulations. DESC is also working with the EPA and state regulatory agencies to assess the applicability of Section 316(b) to five hydroelectric facilities. DESC anticipates that it may have to install impingement control technologies at certain of these stations that have once-through cooling systems. DESC is currently evaluating the need or potential for entrainment controls under the final rule as these decisions will be made on a case-by-case basis after a thorough review of detailed biological, technological, and cost benefit studies. DESC is conducting studies and implementing plans as required by the rule to determine appropriate intake structure modifications at certain facilities to ensure compliance with this rule. While the impacts of this rule could be material to DESC's results of operations, financial condition and/or cash flows, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts for DESC.

Effluent Limitations Guidelines

In September 2015, the EPA released a final rule to revise the ELG Rule. The final rule established updated standards for wastewater discharges that apply primarily at coal and oil steam generating stations. Affected facilities are required to convert from wet to dry or closed cycle coal ash management, improve existing wastewater treatment systems and/or install new wastewater treatment technologies in order to meet the new discharge limits. In April 2017, the EPA granted two separate petitions for reconsideration of the final ELG Rule and stayed future compliance dates in the rule. Also in April 2017, the U.S. Court of Appeals for the Fifth Circuit granted the EPA's request for a stay of the pending consolidated litigation challenging the rule while the EPA addresses the petitions for reconsideration. In September 2017, the EPA signed a rule to postpone the earliest compliance dates for certain waste streams regulations in the final ELG Rule from November 2018 to November 2020; however, the latest date for compliance for these regulations was December 2023. In October 2020, the EPA released the final rule that extends the latest dates for compliance. Individual facilities' compliance dates will vary based on circumstances and the determination by state regulators and may range from 2021 to 2028. While the impacts of this rule could be material to DESC's results of operations, financial condition and/or cash flows, as DESC expects that wastewater treatment technology retrofits and modifications at the Wateree generating stations will be required, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts for DESC.

Capacity Use Area

In November 2019, a new CUA was established in the counties surrounding the Cope Generating Station (Western Capacity Use Area) under the South Carolina Groundwater Use and Reporting Regulation. Under the regulation any groundwater well in a CUA that withdraws above three million gallons per month must be permitted. The Cope Generating Station is located within this new Western Capacity Use Area. Cope has been using four deep groundwater wells for cooling water and other house loads since 1996. Prior to designation of the new Western Capacity Use Area, the wells at Cope Station were only required to be registered not permitted. As a result of this designation, Cope will need to restore the surface water equipment to operable status to reduce reliance on groundwater wells. This includes completion of 316(b) requirements, (including SCDHEC BACT determination and modification of the station national pollutant discharge elimination system permit) and extensive inspection, repair and/or replacement of the associated surface water withdrawal equipment which has been idle since 1996. While the impacts of this rule change are potentially material to DESC's results of operations, financial condition and/or cash flows, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts for DESC.

Waste Management and Remediation

The operations of DESC are subject to a variety of state and federal laws and regulations governing the management and disposal of solid and hazardous waste, and release of hazardous substances associated with current and/or historical operations. The CERCLA, as amended, and similar state laws, may impose joint, several and strict liability for cleanup on potentially responsible parties who owned, operated or arranged for disposal at facilities affected by a release of hazardous substances. In addition, many states have created programs to incentivize voluntary remediation of sites where historical releases of hazardous substances are identified and property owners or responsible parties decide to initiate cleanups.

From time to time, DESC may be identified as a potentially responsible party in connection with the alleged release of hazardous substances or wastes at a site. Under applicable federal and state laws, DESC could be responsible for costs associated with the investigation or remediation of impacted sites, or subject to contribution claims by other responsible parties for their costs incurred at such sites. DESC also may identify, evaluate and remediate other potentially impacted sites under voluntary state programs. Remediation costs may be subject to reimbursement under DESC's insurance policies, rate recovery mechanisms, or both. Except as described below, DESC does not believe these matters will have a material effect on results of operations, financial condition and/or cash flows.

DESC has four decommissioned manufactured gas plant sites in South Carolina that are in various states of investigation, remediation and monitoring under work plans approved by, or under review by, the SCDHEC or the EPA. DESC anticipates that activities at these sites will continue through 2025 with a remaining estimated cost of $21 million. DESC expects to recover costs arising from the remediation work at all four sites through rate recovery mechanisms and as of December 31, 2022, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $38 million and are included in regulatory assets.

Ash Pond and Landfill Closure Costs

In April 2015, the EPA enacted a final rule regulating CCR landfills, existing ash ponds that still receive and manage CCRs, and inactive ash ponds that do not receive, but still store, CCRs. DESC currently has inactive and existing CCR ponds and CCR landfills subject to the final rule at two different facilities. This rule created a legal obligation for DESC to retrofit or close all of its inactive and existing ash ponds over a certain period of time, as well as perform required monitoring, corrective action, and post-closure care activities as necessary.

In December 2016, legislation was enacted that creates a framework for EPA- approved state CCR permit programs. In August 2017, the EPA issued interim guidance outlining the framework for state CCR program approval. The EPA has enforcement authority until state programs are approved. The EPA and states with approved programs both will have authority to enforce CCR requirements under their respective rules and programs. In September 2017, the EPA agreed to reconsider portions of the CCR rule in response to two petitions for reconsideration. In March 2018, the EPA proposed certain changes to the CCR rule related to issues remanded as part of the pending litigation and other issues the EPA is reconsidering. Several of the proposed changes would allow states with approved CCR permit programs additional flexibility in implementing their programs. In July 2018, the EPA promulgated the first phase of changes to the CCR rule. In August 2018, the U.S. Court of Appeals for the D.C. Circuit issued its decision in the pending challenges of the CCR rule, vacating and remanding to the EPA three provisions of the rule. Until this matter is resolved and all phases of the CCR rule are promulgated, DESC is unable to precisely estimate potential incremental impacts or costs related to existing coal ash sites in connection with future implementation of the final CCR rule. While such amounts may be material to DESC's results of operations, financial condition and/or cash flows, the existing regulatory framework in South Carolina provides rate recovery mechanisms that could substantially mitigate any such impacts.

Claims and Litigation

The following describes certain legal proceedings involving DESC relating primarily to events occurring before closing of the SCANA Combination. No reference to, or disclosure of, any proceeding, item or matter described below shall be construed as an admission or indication that such proceeding, item or matter is material. For certain of these matters, and unless otherwise noted therein, DESC is unable to estimate a reasonable range of possible loss and the related financial statement impacts, but for any such matter there could be a material impact to its results of operations, financial condition and/or cash flows. For the matters for which DESC is able to reasonably estimate a probable loss, the Consolidated Balance Sheets at December 31, 2022 and 2021 include reserves of $94 million and $211 million, respectively, and insurance receivables of $68 million and $85 million, respectively, included within other receivables. These balances at December 31, 2022 and 2021 include $68 million and $85 million, respectively, of offsetting reserves and insurance receivables related to personal injury or wrongful death cases which are currently pending. For the year ended December 31, 2022, charges included in DESC's Consolidated Statements of Comprehensive Income were inconsequential. DESC's Consolidated Statements of Comprehensive Income for the years ended December 31, 2021 and 2020 include charges of $70 million ($53 million after-tax) and $97 million ($73 million after-tax), respectively, within impairment of assets and other charges, reflected in the Corporate and Other segment.

SCANA Shareholder Litigation

In February 2018, a purported class action was filed against Dominion Energy and certain former directors of SCANA and DESC in the State Court of Common Pleas in Richland County, South Carolina (the Metzler Lawsuit). The plaintiff alleges, among other things, that defendants violated their fiduciary duties to shareholders by executing a merger agreement that would unfairly deprive plaintiffs of the true value of their SCANA stock, and that Dominion Energy aided and abetted these actions. Among other remedies, the plaintiff seeks to enjoin and/or rescind the merger. In February 2018, Dominion Energy removed the case to the U.S. District Court for the District of South Carolina and filed a Motion to Dismiss in March 2018. In September 2019, the U.S. District Court for the District of South Carolina granted the plaintiffs' motion to consolidate the Metzler Lawsuit with another lawsuit regarding the SCANA Merger Agreement to which DESC is not a party. In October 2019, the plaintiffs filed an amended complaint against certain former directors and executive officers of SCANA and DESC, which stated substantially similar allegations to those in the initial lawsuits as well as an inseparable fraud claim. In November 2019, the defendants filed a motion to dismiss. In April 2020, the U.S. District Court for the District of South Carolina denied the motion to dismiss. In May 2020, SCANA filed a motion to intervene, which was denied in August 2020. In September 2020, SCANA filed a notice of appeal with the U.S. Court of Appeals for the Fourth Circuit. In June 2021, the parties reached an agreement in principle to settle this case, along with a related case to which DESC was not a party, subject to court approval, with no financial impact to DESC. In June 2022, this case was dismissed in connection with court approval of the related case to which DESC was not a party.

Employment Class Actions and Indemnification

In August 2017, a case was filed in the U.S. District Court for the District of South Carolina on behalf of persons who were formerly employed at the NND Project. In July 2018, the court certified this case as a class action. In February 2019, certain of these plaintiffs filed an additional case, which case has been dismissed and the plaintiffs have joined the case filed August 2017. The plaintiffs allege, among other things, that SCANA, DESC, Fluor Corporation and Fluor Enterprises, Inc. violated the Worker Adjustment and Retraining Notification Act in connection with the decision to stop construction at the NND Project. The plaintiffs allege that the defendants failed to provide adequate advance written notice of their terminations of employment and are seeking damages, which could be as much as $100 million for 100% of the NND Project. In January 2021, the U.S. District Court for the District of South Carolina granted summary judgment in favor of SCANA, DESC, Fluor Corporation and Fluor Enterprises, Inc. In February 2021, the plaintiffs filed a notice of appeal with the U.S. Court of Appeals for the Fourth Circuit. In November 2021, the U.S. Court of Appeals for the Fourth Circuit affirmed the lower court ruling. In March 2022, the deadline to file an appeal to the Supreme Court of the United States expired.

In September 2018, a case was filed in the State Court of Common Pleas in Fairfield County, South Carolina by Fluor Enterprises, Inc. and Fluor Daniel Maintenance Services, Inc. against DESC and Santee Cooper. The plaintiffs make claims for indemnification, breach of contract and promissory estoppel arising from, among other things, the defendants' alleged failure and refusal to defend and indemnify the Fluor defendants in the aforementioned case. As a result of the ruling in favor of the defendants in the aforementioned case, DESC was able to resolve Fluor's claims for an inconsequential amount.

Governmental Proceedings and Investigations

In June 2018, DESC received a notice of proposed assessment of approximately $410 million, excluding interest, from the SCDOR following its audit of DESC's sales and use tax returns for the periods September 1, 2008 through December 31, 2017. The proposed assessment, which includes 100% of the NND Project, is based on the SCDOR's position that DESC's sales and use tax exemption for the NND Project does not apply because the facility will not become operational. In December 2020, the parties reached an agreement in principle in the amount of $165 million to resolve this matter. In June 2021, the parties executed a settlement agreement which allows DESC to fund the settlement amount through a combination of cash, shares of Dominion Energy common stock or real estate with an initial payment of at least $43 million in shares of Dominion Energy common stock. In August 2021, Dominion Energy issued 0.6 million shares of its common stock to satisfy DESC's obligation for the initial payment under the settlement agreement. In May 2022, Dominion Energy issued an additional 0.9 million shares of its common stock to partially satisfy DESC's remaining obligation under the settlement agreement. In June 2022, DESC requested approval from the South Carolina Commission to transfer certain real estate with a total settlement value of $51 million to satisfy its remaining obligation under the settlement agreement. In July 2022, the South Carolina Commission voted to approve the request and issued its final order in August 2022. In September 2022, DESC transferred certain non-utility property with a fair value of $28 million to the SCDOR under the settlement agreement, resulting in a gain of $19 million ($14 million after-tax) recorded in other income (expense), net in DESC's Consolidated Statements of Comprehensive Income for the year ended December 31, 2022. In December 2022, DESC transferred additional utility property with a fair value of $3 million to the SCDOR, resulting in an inconsequential gain. In October 2022, DESC filed for approval to transfer the remaining real estate with FERC which was received in November 2022. The transfers of such utility properties are expected to be completed by early 2024 and to result in a gain of approximately $20 million upon completion.

Matters Fully Resolved Prior to 2022

Ratepayer Class Actions

In May 2018, a consolidated complaint against DESC, SCANA and the State of South Carolina was filed in the State Court of Common Pleas in Hampton County, South Carolina (the DESC Ratepayer Case). The plaintiffs alleged, among other things, that DESC was negligent and unjustly enriched, breached alleged fiduciary and contractual duties and committed fraud and misrepresentation in failing to properly manage the NND Project, and that DESC committed unfair trade practices and violated state anti-trust laws. In December 2018, the State Court of Common Pleas in Hampton County entered an order granting preliminary approval of a class action settlement. The court entered an order granting final approval of the settlement in June 2019, which became effective in July 2019. The settlement agreement, contingent upon the closing of the SCANA Combination, provided that SCANA and DESC establish an escrow account and proceeds from the escrow account would be distributed to the plaintiffs, after payment of certain taxes, attorneys' fees and other expenses and administrative costs. The escrow account would include (1) up to $2.0 billion, net of a credit of up to $2.0 billion in future electric bill relief, which would inure to the benefit of the escrow account in favor of class members over a period of time established by the South Carolina Commission in its order related to matters before the South Carolina Commission related to the NND Project, (2) a cash payment of $115 million and (3) the transfer of certain DESC-owned real estate or sales proceeds from the sale of such properties, which counsel for the plaintiffs estimated to have an aggregate value between $60 million and $85 million. At the closing of the SCANA Combination, SCANA and DESC funded the cash payment portion of the escrow account. In July 2019, DESC transferred $117 million representing the cash payment, plus accrued interest, to the plaintiffs. Through August 2020, property, plant and equipment with a net recorded value of $22 million had been transferred to the plaintiffs in coordination with the court-appointed real estate trustee to satisfy the settlement agreement. In September 2020, the court entered an order approving a final resolution of the transfer of real estate or sales proceeds with a cash contribution of $38.5 million by DESC and the conveyance of property, plant and equipment with a net recorded value of $3 million, which was completed by DESC in October 2020. In December 2021, the court approved a motion for and DESC completed the repurchase of $8 million of property, plant and equipment previously transferred to the plaintiffs.

In September 2017, a purported class action was filed by Santee Cooper ratepayers against Santee Cooper, DESC, Palmetto Electric Cooperative, Inc. and Central Electric Power Cooperative, Inc. in the State Court of Common Pleas in Hampton County, South Carolina (the Santee Cooper Ratepayer Case). The allegations were substantially similar to those in the DESC Ratepayer Case. In March 2020, the parties executed a settlement agreement relating to this matter as well as the Luquire Case and the Glibowski Case described below. The settlement agreement provided that Dominion Energy and Santee Cooper establish a fund for the benefit of class members in the amount of $520 million, of which Dominion Energy's portion was $320 million of shares of Dominion Energy common stock. In July 2020, the court issued a final approval of the settlement agreement. In September 2020, Dominion Energy issued $322 million of shares of Dominion Energy common stock to satisfy its obligation under the settlement agreement, including interest charges.
In July 2019, a similar purported class action was filed by certain Santee Cooper ratepayers against DESC, SCANA, Dominion Energy and former directors and officers of SCANA in the State Court of Common Pleas in Orangeburg, South Carolina (the Luquire Case). In August 2019, DESC, SCANA and Dominion Energy were voluntarily dismissed from the case. The claims were similar to the Santee Cooper Ratepayer Case. In March 2020, the parties executed a settlement agreement as described above relating to this matter as well as the Santee Cooper Ratepayer Case and the Glibowski Case. This case was dismissed as part of the Santee Cooper Ratepayer Case settlement described above.

RICO Class Action

In January 2018, a purported class action was filed, and subsequently amended, against SCANA, DESC and certain former executive officers in the U.S. District Court for the District of South Carolina (the Glibowski Case). The plaintiff alleged, among other things, that SCANA, DESC and the individual defendants participated in an unlawful racketeering enterprise in violation of RICO and conspired to violate RICO by fraudulently inflating utility bills to generate unlawful proceeds. In March 2020, the parties executed a settlement agreement as described above relating to this matter as well as the Santee Cooper Ratepayer Case and the Luquire Case. This case was dismissed as part of the Santee Cooper Ratepayer Case settlement described above.

FILOT Litigation and Related Matters

In November 2017, Fairfield County filed a complaint and a motion for temporary injunction against DESC in the State Court of Common Pleas in Fairfield County, South Carolina, making allegations of breach of contract, fraud, negligent misrepresentation, breach of fiduciary duty, breach of implied duty of good faith and fair dealing and unfair trade practices related to DESC's termination of the FILOT agreement between DESC and Fairfield County related to the NND Project. The plaintiff sought a temporary and permanent injunction to prevent DESC from terminating the FILOT agreement. The plaintiff withdrew the motion for temporary injunction in December 2017. In July 2021, the parties executed a settlement agreement requiring DESC to pay $99 million, which could be satisfied in either cash or shares of Dominion Energy common stock. Also in July 2021, the State Court of Common Pleas in Fairfield County, South Carolina approved the settlement. In July 2021, Dominion Energy issued 1.4 million shares of Dominion Energy common stock to satisfy DESC's obligation under the settlement agreement.

Governmental Proceedings and Investigations

In September and October 2017, SCANA was served with subpoenas issued by the U.S. Attorney's Office for the District of South Carolina and the Staff of the SEC's Division of Enforcement seeking documents related to the NND Project. In February 2020, the SEC filed a complaint against SCANA, two of its former executive officers and DESC in the U.S. District Court for the District of South Carolina alleging that the defendants violated federal securities laws by making false and misleading statements about the NND Project. In April 2020, SCANA and DESC reached an agreement in principle with the Staff of the SEC's Division of Enforcement to settle, without admitting or denying the allegations in the complaint. In December 2020, the U.S. District Court for the District of South Carolina issued an order approving the settlement which required SCANA to pay a civil monetary penalty totaling $25 million, and SCANA and DESC to pay disgorgement and prejudgment interest totaling $112.5 million, which disgorgement and prejudgment interest amount were deemed satisfied by the settlements in the SCANA Securities Class Action and the DESC Ratepayer Case. SCANA paid the civil penalty in December 2020. The SEC civil action against two former executive officers of SCANA remains pending and is currently subject to a stay granted by the court in June 2020 at the request of the U.S. Attorney's Office for the District of South Carolina.

In addition, the South Carolina Law Enforcement Division is conducting a criminal investigation into the handling of the NND Project by SCANA and DESC. Dominion Energy is cooperating fully with the investigations by the U.S. Attorney's Office and the South Carolina Law Enforcement Division, including responding to additional subpoenas and document requests. Dominion Energy has also entered into a cooperation agreement with the U.S. Attorney's Office and the South Carolina Attorney General's Office. The cooperation agreement provides that in consideration of its full cooperation with these investigations to the satisfaction of both agencies, neither such agency will criminally prosecute or bring any civil action against Dominion Energy or any of its current, previous, or future direct or indirect subsidiaries related to the NND Project. A former executive officer of SCANA entered a plea agreement with the U.S. Attorney's Office and the South Carolina Attorney General's Office in June 2020 and entered a guilty plea with the U.S. District Court for the District of South Carolina in July 2020. Another former executive officer of SCANA entered a plea agreement with the U.S. Attorney's Office and the South Carolina Attorney General's Office in November 2020 and entered guilty pleas in the U.S. District Court for the District of South Carolina and in South Carolina state court in February 2021. As a result of the pleas, Dominion Energy has terminated indemnity for these former executive officers related to these two cases.

Abandoned NND Project

DESC, for itself and as agent for Santee Cooper, entered into an engineering, construction and procurement contract with Westinghouse and WECTEC in 2008 for the design and construction of the NND Project, of which DESC's ownership share is 55%. Various difficulties were encountered in connection with the project. The ability of Westinghouse and WECTEC to adhere to established budgets and construction schedules was affected by many variables, including unanticipated difficulties encountered in connection with project engineering and the construction of project components, constrained financial resources of the contractors, regulatory, legal, training and construction processes associated with securing approvals, permits and licenses and necessary amendments to them within projected time frames, the availability of labor and materials at estimated costs and the efficiency of project labor. There were also contractor and supplier performance issues, difficulties in timely meeting critical regulatory requirements, contract disputes, and changes in key contractors or subcontractors. These matters preceded the filing for bankruptcy protection by Westinghouse and WECTEC in March 2017, and were the subject of comprehensive analyses performed by SCANA and Santee Cooper.

Based on the results of SCANA's analysis, and in light of Santee Cooper's decision to suspend construction on the NND Project, in July 2017, SCANA determined to stop the construction of the units and to pursue recovery of costs incurred in connection with the construction under the abandonment provisions of the Base Load Review Act or through other means. This decision by SCANA became the focus of numerous legislative, regulatory and legal proceedings. Some of these proceedings are described above.

In September 2017, DESC, for itself and as agent for Santee Cooper, filed with the U.S. Bankruptcy Court for the Southern District of New York Proofs of Claim for unliquidated damages against each of Westinghouse and WECTEC. These Proofs of Claim were based upon the anticipatory repudiation and material breach by Westinghouse and WECTEC of the contract, and assert against Westinghouse and WECTEC any and all claims that are based thereon or that may be related thereto.

Westinghouse's reorganization plan was confirmed by the U.S. Bankruptcy Court for the Southern District of New York and became effective in August 2018. In connection with the effectiveness of the reorganization plan, the contract associated with the NND Project was deemed rejected. DESC contested approximately $285 million of filed liens in Fairfield County, South Carolina. Most of these asserted liens were claims that relate to work performed by Westinghouse subcontractors before the Westinghouse bankruptcy, although some of them were claims arising from work performed after the Westinghouse bankruptcy.

DESC and Santee Cooper were responsible for amounts owed to Westinghouse for valid work performed by Westinghouse subcontractors on the NND Project after the Westinghouse bankruptcy filing until termination of the interim assessment agreement. In December 2019, DESC and Santee Cooper entered into a confidential settlement agreement with W Wind Down Co LLC resolving claims relating to the interim assessment agreement.

Further, some Westinghouse subcontractors that made claims against Westinghouse in the bankruptcy proceeding also filed claims against DESC and Santee Cooper in South Carolina state court for damages. Many of these claimants asserted construction liens against the NND Project site. In December 2021, settlements were reached to resolve all remaining claims made by Westinghouse subcontractors. All amounts for which Dominion Energy was ultimately responsible were funded utilizing, and did not exceed, the portion of the Toshiba Settlement allocated for such balances within the SCANA Merger Approval Order recorded in regulatory liabilities on DESC's Consolidated Balance Sheets.

Nuclear Insurance

Under Price-Anderson, DESC (for itself and on behalf of Santee-Cooper) maintains agreements of indemnity with the U.S. Nuclear Regulatory Commission that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Summer. Price-Anderson provides funds up to $13.7 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $450 million by American Nuclear Insurers with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is liable for up to $138 million per reactor owned for each nuclear incident occurring at any reactor in the U.S., provided that not more than $20 million of the liability per reactor would be assessed per year. DESC's maximum assessment, based on its two-thirds ownership of Summer, would be $92 million per incident, but not more than $14 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

DESC currently maintains insurance policies (for itself and on behalf of Santee Cooper) with NEIL. The policies provide coverage to Summer for property damage and outage costs up to $1.06 billion resulting from an event of nuclear origin and up to $1 million resulting from an event of a non-nuclear origin. The NEIL policies in aggregate, are subject to a maximum loss of $1.06 billion for any single loss occurrence. The NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, DESC's portion of the retrospective premium assessment would not exceed $11 million. DESC currently maintains an excess property insurance policy (for itself and on behalf of Santee Cooper) with EMANI. The policy provides coverage to Summer for property damage and outage costs up to $1 million resulting from an event of a non-nuclear origin. The EMANI policy permits retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premium, DESC's portion of the retrospective premium assessment would not exceed an inconsequential amount.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from an incident at Summer exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that DESC's rates would not recover the cost of any purchased replacement power, DESC will retain the risk of loss as a self-insurer. DESC has no reason to anticipate a serious nuclear or other incident. However, if such an incident were to occur, it likely would have a material impact on DESC's results of operations, cash flows and financial position.

Spent Nuclear Fuel

The Nuclear Waste Policy Act of 1982 required that the United States government accept and permanently dispose of high-level radioactive waste and spent nuclear fuel by January 31, 1998, and it imposed on utilities the primary responsibility for storage of their spent nuclear fuel until the repository is available. DESC entered into a Standard Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste with the DOE in 1983. By mutual agreement of the parties, damage award payments and settlement payments are made until the DOE has accepted the same amount of spent fuel from the facility as if it has fully performed its contractual obligations. In 2022, DESC received payment of $1 million for resolution of its share of claims incurred at Summer for the period of January 1, 2021 through December 31, 2021. In 2021, DESC received payment of $1 million for resolution of its share of claims incurred at Summer for the period of January 1, 2020 through December 31, 2020. In 2020, DESC received payment of $4 million for resolution of its share of claims incurred at Summer for the period of January 1, 2019 through December 31, 2019. As of December 31, 2022, the federal government has not accepted any spent fuel from Summer, and it remains unclear when the repository may become available. DESC has constructed an independent spent fuel storage installation to accommodate the spent nuclear fuel output for the life of Summer. DESC may evaluate other technology as it becomes available.

Long-Term Purchase Agreements

At December 31, 2022, DESC had the following long-term commitments that are noncancelable or cancelable only under certain conditions, and that a third party that will provide the contracted goods or services has used to secure financing.

(millions)	2023		2024		2025		2026		2027		Thereafter		Total	
Purchased electric capacity(1)	$	87	$	86	$	87	$	91	$	92	$	762	$	1,205

(1) Includes affiliated amounts with certain solar facilities of $219 million.

Commitments represent estimated amounts payable for energy under power purchase contracts with qualifying facilities which expire at various dates through 2046. Energy payments are generally based on fixed dollar amounts per month and totaled $75 million in 2022, $73 million in 2021 and $64 million in 2020.

13. LEASES

At December 31, 2022 and 2021, DESC had the following lease assets and liabilities recorded in the Consolidated Balance Sheets:

At December 31,	2022		2021	
(millions)				
Lease assets:				
Operating lease assets(1)	$	21	$	19
Finance lease assets(2)		9		13
Total lease assets	$	30	$	32
Lease liabilities:				
Operating lease - current(3)	$	3	$	2
Operating lease - noncurrent(4)		18		17
Finance lease - current(5)		4		5
Finance lease - noncurrent		6		10
Total lease liabilities	$	31	$	34

Total lease liabilities	$ 31	$ 34

(1)Included in other deferred debits and other assets in the Consolidated Balance Sheets.
(2)Included in utility plant, net, in the Consolidated Balance Sheets, net of $20 million and $20 million of accumulated amortization at December 31, 2022 and December 31, 2021, respectively.
(3)Included in other current liabilities in the Consolidated Balance Sheets.
(4)Included in other deferred credits and other liabilities in the Consolidated Balance Sheets.
(5)Included in securities due within one year in the Consolidated Balance Sheets.

At December 31, 2022 and 2021, DESC had the following lease assets and liabilities recorded in the Consolidated Balance Sheets within the FERC accounts noted:

(millions)		Electric	Gas	Common	Nonutility	Total
December 31, 2022						
Operating Leases						
Account 101.1	Property Under Capital Lease	$10	$—	$—	$—	$10
Account 118	Other Utility Plant	—	—	11	—	11
Account 108	Accumulated Provision for Depreciation of Electric Plant	—	—	—	—	—
Account 119	Accumulated Provision for Depreciation and Amortization of Other Electric Plant	—	—	—	—	—
Account 227	Obligations Under Capital Lease - Noncurrent	(7)	—	(11)	—	(18)
Account 243	Obligations Under Capital Lease - Current	(3)	—	—	—	(3)
Finance Leases						
Account 101.1	Property Under Capital Lease	8	—	—	—	8
Account 118	Other Utility Plant	—	1	1	—	2
Account 121	Nonutility Property	—	—	—	1	1
Account 108	Accumulated Provision for Depreciation of Electric Plant	—	—	—	—	—
Account 119	Accumulated Provision for Depreciation and Amortization of Other Electric Plant	—	—	—	—	—
Account 122	Accumulated Provision for Depreciation and Amortization of Nonutility Property	—	—	—	—	—
Account 227	Obligations Under Capital Lease - Noncurrent	(5)	—	(1)	—	(6)
Account 243	Obligations Under Capital Lease - Current	(3)	—	—	(1)	(4)

(millions)		Electric	Gas	Common	Nonutility	Total
December 31, 2021						
Operating Leases						
Account 101.1	Property Under Capital Lease	$6	$-	$-	$-	$6
Account 118	Other Utility Plant	—	—	13	—	13
Account 227	Obligations Under Capital Lease - Noncurrent	(5)	—	(12)	—	(17)
Account 243	Obligations Under Capital Lease - Current	(1)	—	(1)	—	(2)
Finance Leases						
Account 101.1	Property Under Capital Lease	10	—	—	—	10
Account 118	Other Utility Plant	—	1	1	—	2
Account 121	Nonutility Property	—	—	—	2	2
Account 227	Obligations Under Capital Lease - Noncurrent	(7)	(1)	(1)	(1)	(10)
Account 243	Obligations Under Capital Lease - Current	(3)	—	—	(1)	(4)

For the years ended December 31, 2022, 2021 and 2020, total lease cost consisted of the following:

Year Ended December 31,	**2022**	2021	2020
(millions)			
Finance lease cost:			
Amortization	**$ 4**	$ 6	$ 8
Interest	**1**	1	1
Operating lease cost	**4**	4	4
Short-term lease cost	**2**	2	2
Total lease cost	**$ 11**	$ 13	$ 15

For the years ended December 31, 2022, 2021 and 2020, cash paid for amounts included in the measurement of lease liabilities consisted of the following amounts, included in the Consolidated Statements of Cash Flows:

Year Ended December 31,	**2022**	2021	2020
(millions)			
Operating cash flows from finance leases	**$ 0**	$ 1	$ 1
Operating cash flows from operating leases	**4**	4	4
Financing cash flows from finance leases	**4**	6	8

At December 31, 2022 and 2021, the weighted average remaining lease term and weighted average discount rate for finance and operating leases were as follows:

At December 31,	**2022**	2021
Weighted average remaining lease term - finance leases	**3 years**	4 years
Weighted average remaining lease term - operating leases	**17 years**	20 years
Weighted average discount rate - finance leases	**2.91 %**	2.91 %
Weighted average discount rate - operating leases	**3.94 %**	3.97 %

Lease liabilities have the following scheduled maturities:

(millions)	Operating	Finance
2023	$ 4	$ 4
2024	2	3
2025	2	2
2026	2	1
2027	1	—
After 2027	20	—
Total undiscounted lease payments	31	10
Present value adjustment	(10)	—
Present value of lease liabilities	$ 21	$ 10

14. OPERATING SEGMENTS

The Corporate and Other Segment primarily includes specific items attributable to DESC's operating segment that are not included in profit measures evaluated by executive management in assessing the segment's performance or in allocating resources.

In 2022, DESC reported after-tax expenses of $3 million for specific items in the Corporate and Other segment, all of which was attributable to its operating segment.

In 2021, DESC reported after-tax net expenses of $212 million for specific items in the Corporate and Other segment, of which $208 million was attributable to its operating segment.
The net expense for specific items attributable to DESC's operating segment in 2021 primarily related to $266 million ($199 million after-tax) of charges associated with the settlement of the South Carolina electric base rate case and a $70 million ($53 million after-tax) charge associated with litigation.

In 2020, DESC reported after-tax net expenses of $104 million for specific items in the Corporate and Other segment, all of which were attributable to its operating segment.

The net expense for specific items attributable to DESC's operating segment in 2020 primarily related to $99 million ($74 million after-tax) of charges associated with litigation.

The following table presents segment information pertaining to DESC's operations:

Year Ended December 31,	**Dominion Energy South Carolina**	**Corporate and Other**	**Consolidated Total**
(millions)			
2022			
External revenue	$ 3,783	$ —	$ 3,783
Depreciation and amortization	486	—	486
Interest charges, net of AFUDC	213	—	213
Income tax expense (benefit)	126	(1)	125
Comprehensive income (loss) available (attributable) to common shareholder	485	(3)	482
Capital expenditures	675	—	675
Total assets (billions)	15.1	—	15.1
2021			
External revenue	$ 3,146	$ —	$ 3,146
Depreciation and amortization	466	—	466
Interest charges, net of AFUDC	206	(23)	183
Income tax expense (benefit)	124	(116)	8
Comprehensive income (loss) available (attributable) to common shareholder	421	(212)	209
Capital expenditures	736	—	736
Total assets (billions)	14.3	—	14.3
2020			
External revenue	$ 2,739	$ —	$ 2,739
Depreciation and amortization	454	—	454
Interest charges, net of AFUDC	220	6	226
Income tax expense (benefit)	69	(36)	33
Comprehensive income (loss) available (attributable) to common shareholder	410	(113)	297
Capital expenditures	719	—	719
Total assets (billions)	13.9	—	13.9

15. UTILITY PLANT AND NONUTILITY PROPERTY

Major classes of utility plant and other property and their respective balances at December 31, 2022 and 2021 were as follows:

At December 31,	2022	2021
(millions)		
Gross utility plant:		
Generation	$ 5,327	$ 5,290
Transmission	2,145	2,037
Distribution	5,472	5,191
Storage	76	76
General and other	617	601
Intangible	270	241
Construction work in progress	515	454
Nuclear fuel	550	603
Total gross utility plant	$ 14,972	$ 14,493
Gross nonutility property	$ 21	$ 44

Jointly Owned Utility Plant

DESC jointly owns and is the operator of Summer. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership. DESC's share of the direct expenses of Summer is included in the corresponding operating expenses on its income statement. The units associated with the NND Project, net of impairment charges, have been reclassified from construction work in progress to a regulatory asset as a result of the decision to stop their construction. See additional discussion at Note 3.

At December 31,		2022			2021	
		Summer Unit 1			Summer Unit 1	
Percent owned		**66.7%**			66.7%	
Plant in service	**$**	**1.6**	**billion**	$	1.6	billion
Accumulated depreciation	**$**	**751**	**million**	$	725	million
Construction work in progress	**$**	**87**	**million**	$	76	million

Included within other receivables on the balance sheet were amounts due to DESC from Santee Cooper for its share of direct expenses. These amounts totaled $21 million at December 31, 2022 and $32 million at December 31, 2021.

16. AFFILIATED AND RELATED PARTY TRANSACTIONS

DESS, on behalf of itself and its parent company, provided the following services to DESC through December 2020, which were rendered at direct or allocated cost: information systems, telecommunications, customer support, marketing and sales, human resources, corporate compliance, purchasing, financial, risk management, public affairs, legal, investor relations, gas supply and capacity management, strategic planning, general administrative, and retirement benefits. In addition, DESS processed and paid invoices for DESC and was reimbursed. Effective January 2021, DES provides to DESC the services previously provided by DESS. Costs for these services include amounts capitalized. Amounts expensed are primarily recorded in other operations and maintenance – affiliated suppliers and other expense, net in the Consolidated Statements of Comprehensive Income.

DESC transacts with affiliates for certain quantities of electricity in the ordinary course of business. DESC also enters into certain commodity derivative contracts with affiliates. DESC uses these contracts, which are principally comprised of forward commodity purchases, to manage commodity price risks associated with purchases of electricity. See Note 8 for more information.

Year Ended December 31,	2022	2021	2020
(millions)			
Direct and allocated costs from DES and DESS(1)	**210**	230	291
Operating Revenues – Electric from sales to affiliate	**4**	4	4
Operating Revenues – Gas from sales to affiliate	**1**	1	1
Operating Expenses – Other taxes from affiliate	**8**	7	9
Purchases of electricity from solar affiliates	**14**	14	12
Demand and transportation charges from DECG - Fuel used in electric generation	**—**	—	16
Demand and transportation charges from DECG - Gas purchased for resale	**—**	—	36
Purchases of electric generation from affiliate	**153**	160	170

(1)Includes capitalized expenditures of $38 million, $30 million and $81 million for the years ended December 31, 2022, 2021 and 2020, respectively.

At December 31,	2022	2021
(millions)		
Payable to DES	**22**	29
Payable to SCANA	**7**	—
Payable to Public Service Company of North Carolina, Incorporated	**12**	—
Receivable from Public Service Company of North Carolina, Incorporated	**—**	60
Payable to solar affiliates	**—**	1
Receivable from nuclear affiliates	**—**	1
Payable to DEI	**1**	1
Payable to GENCO	**18**	8
Derivative assets with affiliates(1)	**51**	28

(1)Includes amounts recorded in other current assets of $8 million and $4 million as of December 31, 2022 and 2021, respectively, and amounts recorded in other deferred debits and other assets of $43 million and $24 million as of December 31, 2022 and 2021, respectively.

Certain disclosures regarding tax related affiliate balances are included in Note 2. Borrowings from an affiliate are described in Note 6. Certain disclosures regarding DESC's participation in SCANA's noncontributory defined benefit pension plan and unfunded postretirement health care and life insurance programs are included in Note 11.

17. OTHER INCOME (EXPENSE), NET

Components of other income (expense), net are as follows:

Year Ended December 31,		2022		2021		2020
(millions)						
Revenues from contracts with customers	**$**	**—**	$	—	$	1
Other income		**10**		11		13
Gain on sales of assets (1)		**42**		—		—
Other expense		**2**		(18)		(38)
Allowance for equity funds used during construction		**—**		4		—
Other expense, net	**$**	**54**	$	(3)	$	(24)

18. SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $188 million and $171 million in 2022 and 2021, respectively (net of capitalized interest of $7 million and $3 million in 2022 and 2021, respectively.

Income taxes paid: $24 million and $19 million in 2022 and 2021, respectively. Income taxes received: $156 million and $0 million in 2022 and 2021, respectively.

Noncash Investing and Financing Activities:
Accrued construction expenditures: $122 million and $105 million at December 31, 2022 and 2021, respectively.
Capital lease expenditures: There were no expenditures related to financing leases for the years ended December 31, 2022 or 2021.

See Note 5 for noncash financing activities related to capital contributions associated with the settlement of litigation.
See Note 12 for noncash investing activities related to the property, plant and equipment conveyed to satisfy litigation.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-For-Sale Securities (b)	Minimum Pension Liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	Balance of Account 219 at Beginning of Preceding Year				[(a)](1,652,649)			[(g)](1,652,649)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(b)]94,635			94,635		
3	Preceding Quarter/Year to Date Changes in Fair Value				[(c)]975,412			975,412		
4	Total (lines 2 and 3)				1,070,047			1,070,047	208,137,641	209,207,688
5	Balance of Account 219 at End of Preceding Quarter/Year				(582,602)			(582,602)		
6	Balance of Account 219 at Beginning of Current Year				(582,602)			(582,602)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				[(d)]12,755			12,755		
8	Current Quarter/Year to Date Changes in Fair Value				[(e)](947,333)			(947,333)		
9	Total (lines 7 and 8)				(934,578)			(934,578)	482,587,046	481,652,468
10	Balance of Account 219 at End of Current Quarter/Year				[(f)](1,517,180)			(1,517,180)		

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossBalance

Lines 1-5 present information for the period 1/1/21 - 12/31/21.
Lines 6-10 present information for the period 1/1/22 - 12/31/22.

(b) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Reflects reclassification adjustments of amounts recognized in AOCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit costs in 2021.

(c) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossChangesInFairValue

Amount reflects adjustment to AOCI, and reclassification to expense, for changes in fair value of employee benefit plan obligations. Amount reflects amounts recognized in AOCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service costs arising during 2021 (as applicable).

(d) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossReclassificationsToNetIncomeLoss

Reflects reclassification adjustments of amounts recognized in AOCI (net losses and prior service costs, as applicable) pursuant to accounting requirements for deferred employee benefit plan costs. These adjustments result from the amortization of those amounts as components of net periodic benefit costs in 2022

(e) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossChangesInFairValue

Amount reflects adjustment to AOCI, and reclassification to expense, for changes in fair value of employee benefit plan obligations. Also reflects amounts recognized in AOCI pursuant to accounting requirements for deferred employee benefit plan costs that are attributable to net gains or losses and prior service costs arising during 2022 (as applicable)

(f) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossBalance

Other Comprehensive Income related to deferred employee benefit plan costs

(g) Concept: AccumulatedOtherComprehensiveIncomeLoss

Lines 1-5 present information for the period 1/1/21 - 12/31/21.
Lines 6-10 present information for the period 1/1/22 - 12/31/22.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company For the Current Year/Quarter Ended (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)
1	UTILITY PLANT							
2	In Service							
3	Plant in Service (Classified)	13,158,382,891	11,284,544,010	1,521,566,739				352,272,142
4	Property Under Capital Leases	30,053,706	17,335,957	597,180				12,120,569
5	Plant Purchased or Sold							
6	Completed Construction not Classified	711,876,279	499,426,534	161,927,355				50,522,390
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	13,900,312,876	11,801,306,501	1,684,091,274				414,915,101
9	Leased to Others							
10	Held for Future Use	9,179,850	9,179,850					
11	Construction Work in Progress	514,217,273	436,894,984	65,141,437				12,180,852
12	Acquisition Adjustments	31,597,076	31,360,826	236,250				
13	Total Utility Plant (8 thru 12)	14,455,307,075	12,278,742,161	1,749,468,961				427,095,953
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	5,620,270,875	4,867,326,514	559,278,916				193,665,445
15	Net Utility Plant (13 less 14)	8,835,036,200	7,411,415,647	1,190,190,045				233,430,508
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	5,395,023,625	4,776,254,480	544,227,842				74,541,303
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights							
20	Amortization of Underground Storage Land and Land Rights							
21	Amortization of Other Utility Plant	213,271,917	79,247,984	14,899,791				119,124,142
22	Total in Service (18 thru 21)	5,608,295,542	4,855,502,464	559,127,633				193,665,445
23	Leased to Others							
24	Depreciation							
25	Amortization and Depletion							
26	Total Leased to Others (24 & 25)							

27	Held for Future Use							
28	Depreciation							
29	Amortization							
30	Total Held for Future Use (28 & 29)							
31	Abandonment of Leases (Natural Gas)							
32	Amortization of Plant Acquisition Adjustment	11,975,333	11,824,050	151,283				
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,620,270,875	4,867,326,514	559,278,916				193,665,445

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)	Changes during Year Amortization (d)	Changes during Year Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)					
2	Fabrication	799,801	6,675,649		[b]799,801	6,675,649
3	Nuclear Materials		40,805,957			40,805,957
4	Allowance for Funds Used during Construction		612,640			612,640
5	(Other Overhead Construction Costs, provide details in footnote)	52,445	[a]417,416			469,861
6	SUBTOTAL (Total 2 thru 5)	852,246	48,511,662		799,801	48,564,107
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	142,677,977	18,990,067		[c]41,227,797	120,440,247
9	In Reactor (120.3)	164,301,564	805,837			165,107,401
10	SUBTOTAL (Total 8 & 9)	306,979,541	19,795,904		41,227,797	285,547,648
11	Spent Nuclear Fuel (120.4)	295,504,260			[d]79,454,828	216,049,432
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	387,545,863		(38,568,240)	[e]79,454,828	346,659,275
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	215,790,184	68,307,566	38,568,240	42,027,598	203,501,912
15	Estimated Net Salvage Value of Nuclear Materials in Line 9					
16	Estimated Net Salvage Value of Nuclear Materials in Line 11					
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing					
18	Nuclear Materials held for Sale (157)					
19	Uranium					
20	Plutonium					
21	Other (Provide details in footnote)					
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)					

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationAdditions

Additions for Other Overhead Construction Costs includes Fuel labor-related expenses of $361,887 and Software License expenses of $55,529.

(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Transfer fuel balances from Batch 29 In-Process to Batch 29 - In reactor.

(c) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions

Transfer fuel invoices/balances from Nuclear Fuel-Stock to Batch 30 - In Process.

(d) Concept: SpentNuclearFuelOtherReductions

Nuclear Fuel Transfers - Offset Spent Fuel costs against Amortized Fuel cost, per FERC Instructions for spent nuclear fuel batches on the books beyond cooling period.

(e) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesOtherReductions

Nuclear Fuel Transfers - Offset Spent Fuel costs against Amortized Fuel cost, per FERC Instructions for spent nuclear fuel batches on the books beyond cooling period.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of the prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization	7,287,665					7,287,665
3	(302) Franchise and Consents	13,156,558					13,156,558
4	(303) Miscellaneous Intangible Plant	78,245,358	10,397,611	38,234		(3,160,663)	85,444,072
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	98,689,581	10,397,611	38,234		(3,160,663)	105,888,295
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	13,457,716	21,103	115			13,478,704
9	(311) Structures and Improvements	280,995,280	(7,574,224)	1,274,215			272,146,841
10	(312) Boiler Plant Equipment	1,190,676,094	43,768,069	9,167,223		(216,102)	1,225,060,838
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	513,587,979	18,233,347	3,299,756			528,521,570
13	(315) Accessory Electric Equipment	94,185,247	5,338,167	270,260			99,253,154
14	(316) Misc. Power Plant Equipment	44,305,981	7,270,281	2,570,651			[a]49,005,611
15	(317) Asset Retirement Costs for Steam Production	4,525,638	6,023,398	6,023,398			4,525,638
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,141,733,935	73,080,141	22,605,618		(216,102)	2,191,992,356
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	880,612					880,612
19	(321) Structures and Improvements	393,932,638	(4,365,223)	362,722		2,889,439	[b]392,094,132
20	(322) Reactor Plant Equipment	561,036,243	3,187,137	1,424,238			562,799,142
21	(323) Turbogenerator Units	110,011,090	1,372,465	609,136			110,774,419
22	(324) Accessory Electric Equipment	118,863,453	1,056,402	387,569			119,532,286
23	(325) Misc. Power Plant Equipment	209,180,533	8,740,836	862,407		271,223	[c]217,330,185

24	(326) Asset Retirement Costs for Nuclear Production	62,564,231					62,564,231
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,456,468,800	9,991,617	3,646,072		3,160,662	1,465,975,007
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	29,515,571	44,635			(1,981)	29,558,225
28	(331) Structures and Improvements	51,781,815	625,152	57,538			52,349,429
29	(332) Reservoirs, Dams, and Waterways	449,018,708	6,810,603	196,727			455,632,584
30	(333) Water Wheels, Turbines, and Generators	90,104,452	5,916,798	58,032			95,963,218
31	(334) Accessory Electric Equipment	35,227,340	865,377	12,301			36,080,416
32	(335) Misc. Power Plant Equipment	13,301,086	318,949	43,793			13,576,242
33	(336) Roads, Railroads, and Bridges	1,817,517					1,817,517
34	(337) Asset Retirement Costs for Hydraulic Production						
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	670,766,489	14,581,514	368,391		(1,981)	684,977,631
36	D. Other Production Plant						
37	(340) Land and Land Rights	2,918,325		890			2,917,435
38	(341) Structures and Improvements	47,944,961	1,782,285	1,533,639		216,102	48,409,709
39	(342) Fuel Holders, Products, and Accessories	13,576,701	(22,877)	957,012			12,596,812
40	(343) Prime Movers	656,284,694	19,222,987	19,128,818			656,378,863
41	(344) Generators	202,216,898	(616,870)	9,008,565			192,591,463
42	(345) Accessory Electric Equipment	69,336,650	1,190,376	2,934,120			67,592,906
43	(346) Misc. Power Plant Equipment	4,062,735	395,546	222,291			4,235,990
44	(347) Asset Retirement Costs for Other Production	(5,810,719)					(5,810,719)
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	990,530,245	21,951,447	33,785,335		216,102	978,912,459
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	5,259,499,469	119,604,719	60,405,416		3,158,681	5,321,857,453
47	3. Transmission Plant						
48	(350) Land and Land Rights	120,264,073	1,032,887	172,517			[a]121,124,443
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	6,647,605	591,997			(45,793)	7,193,809
50	(353) Station Equipment	676,955,556	13,015,549	2,070,292		45,793	687,946,606
51	(354) Towers and Fixtures	3,960,446					3,960,446
52	(355) Poles and Fixtures	759,883,936	88,356,266	1,367,596			846,872,606
53	(356) Overhead Conductors and Devices	388,371,416	8,561,216	313,950			396,618,682
54	(357) Underground Conduit	19,549,115					19,549,115
55	(358) Underground Conductors and Devices	57,699,638					57,699,638
56	(359) Roads and Trails	73,767					73,767

57	(359.1) Asset Retirement Costs for Transmission Plant						
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	2,033,405,552	111,557,915	3,924,355			[g] 2,141,039,112
59	4. Distribution Plant						
60	(360) Land and Land Rights	65,978,838	2,298,224			772,826	69,049,888
61	(361) Structures and Improvements	3,019,650		2,349			3,017,301
62	(362) Station Equipment	455,412,238	28,629,813	1,363,332			482,678,719
63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	526,711,604	19,098,588	3,066,388			542,743,804
65	(365) Overhead Conductors and Devices	583,982,455	26,921,387	2,098,344			608,805,498
66	(366) Underground Conduit	178,328,662	7,384,930	64,868			185,648,724
67	(367) Underground Conductors and Devices	534,006,474	21,842,743	1,269,347			554,579,870
68	(368) Line Transformers	551,282,891	25,613,385	413,939			576,482,337
69	(369) Services	326,555,052	4,832,986	4,387,283			327,000,755
70	(370) Meters	176,542,130	26,946,601	25,257,114		1,787,675	180,019,292
71	(371) Installations on Customer Premises						
72	(372) Leased Property on Customer Premises						
73	(373) Street Lighting and Signal Systems	407,625,397	32,301,803	1,828,625		(3,319,731)	434,778,844
74	(374) Asset Retirement Costs for Distribution Plant	106,484		69,125		3,319,731	3,357,090
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,809,551,875	195,870,460	39,820,714		2,560,501	3,968,162,122
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT						
77	(380) Land and Land Rights						
78	(381) Structures and Improvements						
79	(382) Computer Hardware						
80	(383) Computer Software						
81	(384) Communication Equipment						
82	(385) Miscellaneous Regional Transmission and Market Operation Plant						
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper						
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)						
85	6. General Plant						
86	(389) Land and Land Rights	13,678,856	11,056,271			(184,852)	24,550,275
87	(390) Structures and Improvements	112,751,857	4,455,857	38,051			117,169,663
88	(391) Office Furniture and Equipment	15,820,237	449,316	308,339		(1,787,675)	14,173,539
89	(392) Transportation Equipment	23,780,822	4,354,096	1,401,811		7,449	26,740,556
90	(393) Stores Equipment	80,474					80,474
91	(394) Tools, Shop and Garage Equipment	4,461,330	772,479	39,187			5,194,622

92	(395) Laboratory Equipment	6,592,522	178,779	137,097			6,634,204
93	(396) Power Operated Equipment	53,642,759	10,895,765	4,200,708			60,337,816
94	(397) Communication Equipment	6,278,973	224,496	14,994			6,488,475
95	(398) Miscellaneous Equipment	6,796,771	421,905	255,872		(3,972,909)	2,989,895
96	SUBTOTAL (Enter Total of lines 86 thru 95)	243,884,601	32,808,964	6,396,059		(5,937,987)	264,359,519
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant						
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	243,884,601	32,808,964	6,396,059		(5,937,987)	264,359,519
100	TOTAL (Accounts 101 and 106)	11,445,031,078	470,239,669	110,584,778		(3,379,468)	11,801,306,501
101	(102) Electric Plant Purchased (See Instr. 8)						
102	(Less) (102) Electric Plant Sold (See Instr. 8)						
103	(103) Experimental Plant Unclassified						
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	11,445,031,078	470,239,669	110,584,778		(3,379,468)	11,801,306,501

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MiscellaneousPowerPlantEquipmentSteamProduction

As a result of the adoption of new accounting guidance for leases (Accounting Standards Codification 842) in 2020, the ending balances for the plant accounts identified below contain operating leases as follows:

Functional Class	Plant Account		Operating Leases Balance at December 31, 2022
Steam Production	316 -	Misc Power Plant Equipment	$5,213,076
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,553,851

(b) Concept: StructuresAndImprovementNuclearProduction

As a result of the adoption of new accounting guidance for leases (Accounting Standards Codification 842) in 2020, the ending balances for the plant accounts identified below contain operating leases as follows:

Functional Class	Plant Account		Operating Leases Balance at December 31, 2022
Steam Production	316 -	Misc Power Plant Equipment	$5,213,076
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,553,851

(c) Concept: MiscellaneousPowerPlantEquipmentNuclearProduction

As a result of the adoption of new accounting guidance for leases (Accounting Standards Codification 842) in 2020, the ending balances for the plant accounts identified below contain operating leases as follows:

Functional Class	Plant Account		Operating Leases Balance at December 31, 2022
Steam Production	316 -	Misc Power Plant Equipment	$5,213,076
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,553,851

(d) Concept: LandAndLandRightsTransmissionPlant

As a result of the adoption of new accounting guidance for leases (Accounting Standards Codification 842) in 2020, the ending balances for the plant accounts identified below contain operating leases as follows:

Functional Class	Plant Account		Operating Leases Balance at December 31, 2022
Steam Production	316 -	Misc Power Plant Equipment	$5,213,076
Nuclear Production	321 -	Structures and Improvements	$4,861
Transmission	350 -	Land and Land Rights	$4,553,851

(e) Concept: TransmissionPlant

For the formula rate approved in the FERC proceeding listed on page 106, Total Transmission Plant will exclude $4,553,851 of operating leases in Plant Account 350 – Land and Land Rights .

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (a)	* (Designation of Associated Company) (b)	Description of Property Leased (c)	Commission Authorization (d)	Expiration Date of Lease (e)	Balance at End of Year (f)
1	[(a)] See Footnote					
47	TOTAL					

FOOTNOTE DATA

(a) Concept: LesseeName

The Company charges a rental fee to Segra for communication tower site ground leases.

Dominion Energy Services, Inc. utilizes certain assets, including both office space and equipment, that are owned by Dominion Energy South Carolina (DESC) and classified as electric, gas and common utility plant on the Company's books. DESC charges Dominion Energy Services, Inc. a rental fee for such asset usage.

See Transactions with Associated Companies Schedule on page 429 for additional details.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Clements Ferry Sub Site Easement	07/01/2020	[(a)] 07/01/2027	1,037,100
3	Cainhoy-Clements Ferry 115kv Underground Easement	07/01/2020	[(b)] 07/01/2027	4,767,750
4	Clements Ferry-Jack Primus 115kv Underground 50' R/W	07/01/2020	[(c)] 07/01/2027	3,375,000
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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41				
42				
43				

44				
45				
46				
47	TOTAL			9,179,850

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Estimated expected date to be used in utility service is approximately 2027.
(b) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Estimated expected date to be used in utility service is approximately 2027.
(c) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate
Estimated expected date to be used in utility service is approximately 2027.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Steam Production	
2	URQUHART Wastewater System	7,781,219
3	WATEREE 1 TIL-1277 and Turbine Bucket Rep	2,580,357
4	WATEREE 1 Baghouse Bag Replacement	1,329,720
5	WATEREE 2 Baghouse Bags Fall 2020	1,241,538
6	Minor Steam Production	12,068,421
7	Nuclear Production	
8	VCS SLR Application	10,315,325
9	VCS Unit 1 License Renewal Project	10,216,303
10	S/R "Bravo" Chiller Replacement	8,417,918
11	Open Phase Detection System	7,978,738
12	SW Chemical Treatment Equipment	5,662,015
13	Simplex Equipment Replacement	5,132,281
14	DG Exciter Replacement - Bravo	3,924,683
15	"C" Chiller Replacement	3,908,141
16	Alpha DG Exciter Replacement	3,694,900
17	VCS Transformer Replacement	3,319,143
18	Replace RMWST Heat Tracing	2,866,689
19	ABB DCS Cabinets	2,225,706
20	NSMART Security Computer Replacement	1,644,277
21	Condensate Flow Control Valve Replc	1,625,454
22	Alpha SW 20" Cavitation Elimination	1,535,717
23	Inverters 5903-5904 Replacement	1,214,007
24	S/R PORV Controls	1,119,204
25	Feedwater Isolation Valve Actuators	1,023,022
26	Minor Nuclear Production	15,629,546
27	Hydro Production	
28	Saluda Headgate Replacement	6,899,177

29	PARR SHOALS #3 Turbine Runner		1,629,898
30	PARR Hydro Gen Rewinds		1,500,271
31	Neal Shoals 3-4 Head Gates & LLSG's		1,264,065
32	Minor Hydro Production		5,230,447
33	Other Production		
34	Parr CT Replacement		36,718,433
35	Bushy Park CT Replacement		22,719,012
36	COLUMBIA ENERGY CENTER CT1 AGP Upgrade & 2.6+ Upgrade		21,621,604
37	COLUMBIA ENERGY CENTER CT1 Dual Fuel Conversion		2,338,416
38	Minor Other Production		4,934,544
39	Overhead Transmission Lines		
40	Yemassee-Burton 230 (115) kV		49,545,501
41	Sal Hyd Harbison 115 Reterminate to LM		9,081,138
42	Queensboro - Johns Island Tie		7,627,603
43	Church Creek - Queensboro: 230(115):Const		7,505,500
44	Wateree-Hopkins 230kV Line #2: Rebu		6,181,751
45	Church Creek - Queensboro Stono Rebld		5,713,030
46	Eastover - Square D 115 kV: Rebuild		5,195,627
47	Queensboro - Ft. Johnson 115kV		4,380,296
48	Burton-St Helena 115 kV: Rebuild		4,061,855
49	Church Creek Ritter 230kV Replace P		3,593,191
50	May River 115kV Tap		1,527,965
51	Minor Elec Overhead Transmission Lines		9,497,311
52	Minor Elec Underground Transmission Lines		226,909
53	Transmission Substation		
54	Denny Terrace - Repl Sw House		2,630,869
55	Burton: Term Updg & Install Relays		2,142,022
56	Williams St: Add 115-23kV Transf		2,132,302
57	Okatie 230/115kV: Construct		1,750,864
58	Transm Subs: Repl Breakers Phase B		1,506,319
59	Faber Place Sub: Replace 1 & 2 Swit		1,365,465
60	Faber Place Sub Replace Breakers		1,134,150
61	Minor Transmission Substation		8,068,490
62	Distribution Substation		
63	May River 115-23kV Sub: Construct		3,125,543

64	Dist Subs: Replace Breakers Phase B		2,723,284
65	Distribution Sub: Replace Breakers		1,587,922
66	Cope Distribution 115-23kV Construc		1,577,740
67	Whiskey Road 115-12kV Sub: Construc		1,073,543
68	Saxe Gotha Sub:Add 115-23kV 37.3MVA		1,014,976
69	Minor Distribution Substation		8,017,464
70	Customer Substation		
71	Longwood Sub: Add 37.3 MVA Bank		2,058,560
72	Savannah River Site 13-1,15-1,15-2 rplc motor mechs		1,376,718
73	Minor Customer Substation		2,420,635
74	Overhead Distribution Line		
75	Burton to Yemassee 115kv Rebuild		2,411,503
76	Minor Overhead Distribution Line		14,039,654
77	U/G Distribution Lines		
78	Park/Network Tie		1,184,298
79	Minor U/G Distribution Lines		11,427,953
80	Land and Structures		
81	Primary Control Room Upgrades		6,076,793
82	DESC Johnston Crew Quarters		2,609,845
83	Backup Control Room Upgrade		2,500,418
84	Savage Road New Building		1,218,632
85	Minor Land and Structures		1,840,344
86	Transportation & POE		
87	Minor Transportation & POE		4,883,845
88	Office Furniture and Equipment		
89	Minor Office Furniture and Equipment		1,140,472
90	Communication Equipment		
91	Minor Communication Equipment		939,166
92	Tools & Test Equipment		
93	Minor Tools & Test Equipment		182,188
94	Intangible Plant		
95	Oracle NMS 2.5 Upgrade		1,062,999
96	Minor Intangible Plant		4,222,140
43	Total		436,894,984

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 12, column (c), and that reported for electric plant in service, page 204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased To Others (e)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	4,642,423,053	4,642,423,053		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	266,646,462	266,646,462		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,812,354	5,812,354		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	1,123,247	[a]1,123,247		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	273,582,063	273,582,063		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(105,043,332)	[b](105,043,332)		
13	Cost of Removal	(53,204,877)	(53,204,877)		
14	Salvage (Credit)	1,848,846	1,848,846		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(156,399,363)	(156,399,363)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	16,648,727	[c]16,648,727		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,776,254,480	4,776,254,480		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,119,629,166	1,119,629,166		
21	Nuclear Production	705,369,761	705,369,761		
22	Hydraulic Production-Conventional	303,621,771	303,621,771		
23	Hydraulic Production-Pumped Storage	83,672,131	83,672,131		
24	Other Production	644,095,363	644,095,363		

25	Transmission	553,289,236	553,289,236		
26	Distribution	1,278,046,467	1,278,046,467		
27	Regional Transmission and Market Operation				
28	General	88,530,585	88,530,585		
29	TOTAL (Enter Total of lines 20 thru 28)	4,776,254,480	4,776,254,480		

FOOTNOTE DATA

(a) Concept: OtherAccounts

Depreciation of Asset Retirement Costs recorded as a regulatory asset.

(b) Concept: BookCostOfRetiredPlant

Retirements per Page 207, Line 100 Column (d)	$	110,584,778
Less: Intangible Plant per Page 205, Line 5 column (d)		(38,234)
Less: Capital and Operating Lease Asset Reductions Recorded in Accordance with USoA General Instruction No. 20, Shown as Plant Retirements		(5,503,212)
Total	$	105,043,332

(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

ARC retirements reclassified to Regulatory Assets	6,032,020
Loss on meters retired due to AMI project	6,172,004
Loss on Disposal on Assets	3,867,584
Book Cost of Land Retired	1,005
Gain on Disposal on Vehicles	(186,847)
Transfers and Adjustments	762,961
Total	$16,648,727

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-TOTAL by company and give a TOTAL in columns (e), (f), (g) and (h). (a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate. (b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.
4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Canady's Refined Coal, LLC - Unspecified Investments in Subsidiary Companies			0	58,122		[a]0	
2	Louisa Refined Coal, LLC - Unspecified Investments in Subsidiary Companies			13,124	(62,866)		[b]5,573	
3	Brandon Shores Coaltech, LLC - Unspecified Investments in Subsidiary Companies			0	(44,770)		[c]0	
4	Brunner Island Refined Coal, LLC - Unspecified Investments in Subsidiary Companies			0	50,451		[d]0	
5	Cope Refined Coal, LLC - Unspecified Investments in Subsidiary Companies			0				[e]3,126
42	Total Cost of Account 123.1 $		Total	13,124	[f]937		5,573	3,126

FERC FORM No. 1 (ED. 12-89)

FOOTNOTE DATA

(a) Concept: InvestmentInSubsidiaryCompanies

The balance of this investment at the beginning of the year was actually a credit of $114,398 which was reclassified on the Company's books to Account No. 234 at 12/31/21. Therefore no beginning balance in Account No. 123.1 is shown in column (d). The $58,122 activity in column (e) represents net income during the year. This $58,122 of activity lowered the credit balance to $56,276 which is reflected in Account No. 234 and not Account No. 123.1 on the Company's ledger.

(b) Concept: InvestmentInSubsidiaryCompanies

Additional investments made during the year of $55,315.

(c) Concept: InvestmentInSubsidiaryCompanies

Additional investments made during the year of $99,819.

The balance of this investment at the beginning of the year was actually a credit of $204,142 which was reclassified on the Company's books to Account No. 234 at 12/31/21. Therefore no beginning balance in Account No. 123.1 is shown in column (d). The $44,770 activity in column (e) represents net losses incurred during the year. This $44,770 of activity plus the current year additional investments increased the credit balance to $149,093 which is reflected in Account No. 234 and not Account No. 123.1 on the Company's ledger.

(d) Concept: InvestmentInSubsidiaryCompanies

The balance of this investment at the beginning of the year was actually a credit of $35,434 which was reclassified on the Company's books to Account No. 234 at 12/31/21. Therefore no beginning balance in Account No. 123.1 is shown in column (d). The $50,451 activity in column (e) represents net income incurred during the year. This $50,451 of activity this year plus the current year investment cash refunded to the Company cleared the balance to $0 on the Company's ledger .

(e) Concept: InvestmentGainLossOnDisplosal

In 2012, DESC sold its 10% interest in Cope Refined Coal, LLC and is being paid for such interest over future periods. This amount reflects such payment received in 2022 and has been recorded in Account 421 - Miscellaneous Nonoperating Income.

(f) Concept: EquityInEarningsOfSubsidiaryCompanies

Per the USoA instructions, the Company is using Account 418.1 - Equity in Earnings of Subsidiary Companies to account for its equity method losses related to corporate joint ventures carried in Account 123.1 - Investment in Subsidiary Companies. Since these equity method losses are funded by the Company, there are no undistributed retained earnings related to these investments.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	42,992,386	63,773,029	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	120,986,273	130,629,270	Electric
8	Transmission Plant (Estimated)	8,562,336	9,857,696	Electric
9	Distribution Plant (Estimated)	38,872,362	60,634,025	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	555,441	[a]1,762,486	Fleet
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	168,976,412	202,883,477	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	989,327		Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies	212,958,125	266,656,506	

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FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Fleet materials, supplies inventory, and fuel.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	Year One No. (d)	Year One Amt. (e)	Year Two No. (f)	Year Two Amt. (g)	Year Three No. (h)	Year Three Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)
1	Balance-Beginning of Year	621,143.80	624,403	66,892.00		66,892.00		45,625.00		1,186,250.00		1,986,802.80	624,403
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	[(a)]6,794.20								[(b)]45,625.00		52,419.20	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509												
19	Other:												
20	Allowances Used												
20.1	Allowances Used	1,961.80	1,484									1,961.80	1,484
21	Cost of Sales/Transfers:												
22													

23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	625,976.20	622,919	66,892.00		66,892.00		45,625.00		1,231,875.00		2,037,260.20	622,919
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year	659.50		659.50		659.50		659.50		32,315.50		34,953.50	
37	Add: Withheld by EPA									1,319.00		1,319.00	
38	Deduct: Returned by EPA												
39	Cost of Sales	659.50								659.50		(c)1,319.00	
40	Balance-End of Year	0.00		659.50		659.50		659.50		32,975.00		34,953.50	
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesIssuedLessWithheldAllowancesNumber
EPA allocated new unit set aside emission allowances related to the CSAPR SO2 Group 2 Program.
(b) Concept: AllowancesIssuedLessWithheldAllowancesNumber
EPA allocated vintage 2052 emission allowances related to the SO2 Acid Rain Program.
(c) Concept: AllowancesWithheldCostOfSalesNumber
Total sales of auction allowance reserves set aside by the EPA.

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Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on Line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.
6. Report on Line 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquired and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of and identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		Year One		Year Two		Year Three		Future Years		Totals	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)	No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)
1	Balance-Beginning of Year	45,219.20		7,370.00		7,370.00						59,959.20	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	[(a)]1,646.80										1,646.80	
5	Returned by EPA												
6													
7													
8													
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	3,097.50										3,097.50	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												
21	Cost of Sales/Transfers:												

22													
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	43,768.50		7,370.00		7,370.00						58,508.50	
30													
31	Sales:												
32	Net Sales Proceeds(Assoc. Co.)												
33	Net Sales Proceeds (Other)												
34	Gains												
35	Losses												
	Allowances Withheld (Acct 158.2)												
36	Balance-Beginning of Year												
37	Add: Withheld by EPA												
38	Deduct: Returned by EPA												
39	Cost of Sales												
40	Balance-End of Year												
41													
42	Sales												
43	Net Sales Proceeds (Assoc. Co.)												
44	Net Sales Proceeds (Other)												
45	Gains												
46	Losses												

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AllowancesIssuedLessWithheldAllowancesNumber
EPA allocated new unit set aside emission allowances related to the CSAPR NOx Annual Program.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognized During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						

20	TOTAL					

FERC FORM No. 1 (ED. 12-88)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of COmmission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognized During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Unrecovered Plant:					
22	[(a)] Unrecovered Nuclear Project Costs	2,768,106,000		407	138,405,300	2,226,018,575
23	[(b)] Unrecovered Plant related to the retirement of Canadys Unit No. 1.	19,761,879		407	1,607,593	3,685,950
24	[(c)] Unrecovered Plant related to the retirement of Canadys Unit No. 2 and Unit No. 3.	158,111,974	6,314,805	407	12,270,624	46,653,806
25	[(d)] Unrecovered Plant associated with early retirement of coal equipment at Urquhart Unit No. 3.	557,755		407	111,551	409,020
26	[(e)] Unrecovered Plant associated with early retirement of coal equipment at McMeekin Station.	1,427,729		407	285,546	1,047,001
27	[(f)] Unrecovered Plant associated with AMR Meters	17,813,716	6,172,006	407	2,053,414	14,696,418
28	[(g)] Unrecovered Plant associated with Gas Encoder Receiver Transmitters	3,288,643	836,082	407	406,778	2,706,217
29	[(h)] Unrecovered Plant related to the retirement of the Bushy Park Turbines	1,263,488	1,263,488	407	114,312	1,149,176
49	TOTAL	2,970,331,184	14,586,381		155,255,118	2,296,366,163

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

FERC Authorization received October 25, 2019 in Docket No. AC19-188-000. Amortization period February 2019 through January 2039 per SCPSC Docket No. 2017-370-E, Order No. 2018-804.

(b) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received December 20, 2012. (Docket No. 2012-218-E, Order 2012-951). Amortization over approximately 14 years beginning January 2013.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(c) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received September 2013 (Docket No. 2013-276-E, Order 2013-649). Per this SCPSC Order, annual amortization was established at the level of depreciation expense ($12.3 million per year) that was being recorded for the units before their retirement. In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Order No. 2021-570 issued on August 16, 2021 in Docket No. 2020-125-E) the SCPSC affirmed the $12.3 million annual amortization.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(d) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Oder No. 2021-570 issued August 16, 2021 in Docket No. 2020-125-E) the SCPSC approved an annual amortization of $111,551 (5 years) beginning in September 2021.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(e) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Oder No. 2021-570 issued August 16, 2021 in Docket No. 2020-125-E) the SCPSC approved an annual amortization of $285,546 (5 years) beginning in September 2021.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(f) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received September 6, 2019 (Docket No. 2019-241-EG, Order 2019-622). The SCPSC Order set the amortization expense at the level of depreciation currently approved in DESC's rates until DESC's next general retail electric rate case. In the Comprehensive Settlement Agreement approved by the SCPSC in DESC's 2020 Retail Electric Base Rate Case (Order No. 2021-570 issued on August 16, 2021 in Docket No. 2020-125-E) the SCPSC approved an amortization period through December 31, 2028.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(g) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received September 6, 2019 (Docket No. 2019-241-EG, Order 2019-622) and October 14, 2020 (Docket No. 2020-6-G, Order 2020-701). Amortization per the depreciation study approved in Order 2020-701 establishes an amortization period through December 31, 2028.

FERC Authorization received October 21, 2021 in Docket No. AC22-2-000.

(h) Concept: DescriptionOfUnrecoveredPlantAndRegulatoryStudyCosts

SCPSC authorization received July 2022 (Docket Nos. 2022-107-E and 2021-93-E, Order No. 2022-517). Per this SCPSC Order, DESC reclassified the net carrying value related to it's two simple cycle combustion turbines located at Bushy Park to unrecovered plant regulatory asset account upon its retirement. Annual amortization was established at the level of depreciation expense ($457,248 per year) that was being recorded for the units at their retirement date of September 2022.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	20220401001 TSR Initial Study	5,240	408.1/561.6/926	9,000	253
3	20220401001 TSR System Impact Study	954	408.1/561.6/926	6,000	253
4	20220401001 TSR Facilities Study	3,182	408.1/561.6/926		
20	Total	9,376		15,000	
21	**Generation Studies**				
22	Transitional Cluster Phase 1 Study	81,700	408.1/561.7/926		
23	20181030001 System Impact Study			135,000	253
24	20220324001 System Impact Study			125,000	253
25	20220128001 System Impact Study			10,000	253
26	20220118001 System Impact Study			20,000	253
27	20211118001 System Impact Study			28,400	253
28	20211116001 System Impact Study	43,557	561.7		
29	20211118005 System Impact Study			110,400	253
30	20211104002 System Impact Study			53,000	253
31	20211117001 System Impact Study			95,000	253
32	20220225001 System Impact Study	2,114	408.1/561.7/926	12,000	253
33	20171018009 Feasibility Study	2,402	408.1/561.7/926		
34	20220504001 System Impact Study			20,000	253
35	20220601002 System Impact Study			20,000	253
36	20200921003 System Impact Study			29,000	253
37	20200921002 System Impact Study			29,000	253
38	20211206001 System Impact Study			85,000	253
39	20220202001 System Impact Study			10,000	253
40	20200728001 System Impact Study			40,000	253

41	20191204002 System Impact Study				29,000	253
42	20220112001 System Impact Study				205,000	253
43	20211221001 System Impact Study				205,000	253
44	20200824001 System Impact Study				145,000	253
45	20220228001 System Impact Study				10,000	253
46	20220601001 System Impact Study				27,500	253
47	20190110001 System Impact Study				40,000	253
48	20181030002 System Impact Study				135,000	253
49	20220614002 Informational Study				10,000	253
50	20211104001 System Impact Study				145,000	253
51	20220323001 System Impact Study				12,000	253
52	20220421001 System Impact Study				187,500	253
53	20220316001 System Impact Study				215,000	253
54	20191204003 System Impact Study				29,000	253
55	20210310001 System Impact Study				3,145,000	253
56	20200921004 System Impact Study				29,000	253
57	20211118002 System Impact Study				102,800	253
58	20211116002 System Impact Study	41,835	561.7			
59	20210503001 System Impact Study				145,000	253
60	20190729002 System Impact Study				145,000	253
61	20210311001 System Impact Study				145,000	253
62	20211005001 System Impact Study	2,233	408.1/561.7/926			
63	20220509002 System Impact Study	2,267	408.1/561.7/926		3,300	253
64	20211118003 System Impact Study				109,900	253
65	20211118004 System Impact Study				110,900	253
66	20171018011 Feasibility Study	3,048	408.1/561.7/926			
39	Total	179,156			[a]6,152,700	
40	Grand Total	188,532			6,167,700	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: StudyCostsReimbursements

Column (d) represents deposits received to perform study.

An analysis is performed of actual billable costs and if necessary an additional billing is rendered to the study purchaser. Any reimbursements received are transferred from account 253 - Other Deferred Credits and credited to expense as the actual charges are incurred. If reimbursements exceed billable costs, the Company refunds the excess reimbursement, with interest if applicable, to the study purchaser.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Accumulated Deferred Income Taxes	30,180,577	1,493,927	282	2,056,089	29,618,415
2	[a] Gas Water Heater Rebate Program (12/2018-11/2027)	6,751,184	7,922,632	912	7,553,322	7,120,494
3	[b] MGP Environmental Remediation	31,328,924	14,023,753	735	6,913,145	38,439,532
4	[c] Decommissioning Asset Ret. Obligation		89,190,898	128/131	52,857,369	36,333,529
5	[d] Deferred ARO Accretion & Depreciation Costs	318,297,957	33,366,155	108/119	17,727,968	333,936,144
6	[e] Interest Rate Derivatives	290,025,614	7,845,825	244/427	19,951,546	277,919,893
7	Deferred Employee Benefit Plan Costs-Gas (ASC 715)	9,708,434	14,570,163	[ae] see footnote	6,365,922	17,912,675
8	Deferred Employee Benefit Plan Costs-Elec (ASC 715)	54,576,467	80,747,797	[af] see footnote	35,312,912	100,011,352
9	[f] Deferred VCS Coolant Reconfig Costs (7/2010-7/2042)	3,771,071		530	183,816	3,587,255
10	[g] Deferred Capacity Charges (9/2021-8/2024)	1,897,343		555	711,504	1,185,839
11	[h] Electric Demand Side Management	67,963,267	42,845,956	254/908	49,047,098	61,762,125
12	[i] Gas Demand Side Management		505,885	232/921	16,408	489,477
13	[j] Def Pollution Cntrl Costs-Williams (7/2010-2/2045)	6,530,309		555	282,658	6,247,651
14	[k] Economic Development Grants (1/2012-5/2032)	7,902,421		921	973,411	6,929,010
15	[l] Major Maintenance Accrual and Interest	11,900,973	227,338	[ag] see footnote	6,106,655	6,021,656
16	[m] Deferred Pension Cost-Gas (11/2013-1/2027)	5,219,073	85,792	926	1,115,299	4,189,566
17	[n] Deferred Pension Cost-Electric (1/2013-12/2042)	44,762,424	165,653	926	2,153,487	42,774,590
18	[o] Deferred Pollution Control Costs - Wateree (1/2013-9/2040)	19,846,256		407.3	1,061,940	18,784,316
19	[p] Research and Development Grant (1/2013-12/2047)	2,600,000		930.2	100,000	2,500,000
20	[q] Amount Undercollected-Gas Cost Adjustment	6,479,347	189,262,766	[ah] see footnote	157,859,546	37,882,567
21	[r] Amount Undercollected-Elec Fuel Adjustment Clause	115,620,396	507,439,534	[ai] see footnote	170,415,248	452,644,682

22	[s] Gas WNA Cap - Winter 2019/2020 and Winter 2020/2021 (11/2020-10/2022)	768,869		480/481	768,869	
23	[t] Fukushima Compliance Costs (9/2021-8/2031)	4,350,000		524	450,000	3,900,000
24	[u] Cyber Compliance Costs (9/2021-12/2031)	8,422,861		407.3/524	848,619	7,574,242
25	[v] CIPv5 Compliance Costs (9/2021-6/2032)	24,510,784		407.3/566	2,346,450	22,164,334
26	[w] Gas Pipeline Integrity Costs	9,680,296	4,134,791	887	3,241,744	10,573,343
27	[x] Net Operating Loss Excess Deferred Tax Assets	127,428,794		190/410.2	30,391,414	97,037,380
28	[y] Deferred Transmission Operating Costs (9/2021-10/2063)	79,238,907		407.3	1,900,692	77,338,215
29	[z] Deferred Storm Damage Costs	42,288,557	9,697,426	571/593	4,389,969	47,596,014
30	[aa] Undercollected Distributed Energy Resources and Net Metering Costs	6,928,378	34,581,396	[a] see footnote	32,197,362	9,312,412
31	[ab] Deferred AMI Operating Costs (9/2021-5/2078)	4,802,004		407.3	85,157	4,716,847
32	Deferred Costs Pursuant to SC Act 62	1,155,712	1,116,481			2,272,193
33	[ac] 2020 Electric Rate Case Incremental Exp (9/2021-7/2037)	2,796,792	2,055	928	180,048	2,618,799
34	2023 Gas Rate Case Incremental Exp		31,344	920	2,047	29,297
35	Electric Cost Benefit Analysis		170,000			170,000
36	Canady's Ash Pond Closure Costs	3,631,786	919,012	143/232	2,164,318	2,386,480
37	Wholesale Fuel Undercollection	4,244,450	12,813,025	447	80,565	16,976,910
38	[ad] Amt. Overcollected - Vegetation Mgmt Accrual		10,767,748	254	5,668,775	5,098,973
44	TOTAL	1,355,610,227	1,063,927,352		623,481,372	1,796,056,207

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 89-245-G
SCPSC Docket No. 2008-155-G

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2005-113-G

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2003-84-E

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2003-84-E

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Activity associated with this item includes the deferral of losses or gains on certain interest rate derivatives and the amortization of settlement amounts over the life of the related debt issuances.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2008-230-E
SCPSC Docket No. 2020-125-E

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Amortization of deferred balance is a function of customer usage per a Rate Rider mechanism approved by the SCPSC in Docket Nos. 2016-40-E, 2018-42-E, 2019-57-E, 2020-41-E, 2021-34-E, and 2022-52-E.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2021-361-G

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-497-E
SCPSC Docket No. 2011-264-E
SCPSC Docket No. 2012-246-E

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2017-210-E
SCPSC Docket No. 2019-159-E
SCPSC Docket No. 2020-125-E

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-35-G
SCPSC Docket No. 2013-6-G

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2009-489-E
SCPSC Docket No. 2012-218-E

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2008-393-E

SCPSC Docket No. 2012-218-E

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2011-513-E

SCPSC Docket No. 2012-218-E

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2022-5-G

Per SCPSC Docket No. 2005-5-G, commodity and demand components of purchased gas cost are recovered separately. Balances for these components as of December 31, 2022 are as follows:

Commodity	$	58,173,038
Demand		(20,290,471)
Total	$	37,882,567

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2022-2-E

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2020-6-G

SCPSC Docket No. 2021-6-G

(t) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2012-277-E

SCPSC Docket No. 2020-125-E

(u) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2015-372-E

SCPSC Docket No. 2020-125-E

(v) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2014-416-E

SCPSC Docket No. 2020-125-E

(w) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2018-6-G

In the docket referenced above, the SCPSC authorized amortization in a levelized annual amount of $3,182,300 beginning in November 2018.

(x) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2017-381-A

(y) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2017-370-E

SCPSC Docket No. 2020-125-E

(z) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2012-218-E

SCPSC Docket No. 2020-125-E

Pursuant to the comprehensive settlement agreement approved by the SCPSC in DESC's retail electric base rate case (Docket No. 2020-125-E), annual amortization of $4,389,969 began September 2021. The SCPSC's order also authorized additional incremental storm cost deferrals to this account. Therefore, the actual period over which the balance will be amortized will change as additional qualifying deferrals are incurred and recognized.

(aa) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2018-2-E

SCPSC Docket No. 2019-2-E

SCPSC Docket No. 2020-2-E

SCPSC Docket No. 2021-2-E

SCPSC Docket No. 2022-2-E

(ab) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2019-241-EG

SCPSC Docket No. 2020-125-E

(ac) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

SCPSC Docket No. 2020-125-E

(ad) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets
Pursuant to the Comprehensive Settlement Agreement approved by the SCPSC in DESC'S Retail Electric Base Rate Case (Docket No. 2020-125-E), the SCPSC approved a Vegetation Management accrual under which DESC is allowed to recover $27,679,292 annually. Amounts under/(over) collected are deferred as a regulatory asset or regulatory liability, as applicable.
(ae) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
107 / 143 / 182.2 / 183 / 186 / 253 / 926
(af) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
107 / 143 / 182.2 / 183 / 186 / 253 / 926
(ag) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
513 / 553 / 555
(ah) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
173 / 431 / 480 / 481
(ai) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
173 / 254 / 449
(aj) Concept: OtherRegulatoryAssetsWrittenOffAccountCharged
232 / 407.3 / 440 / 442

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Credits Account Charged (d)	CREDITS Credits Amount (e)	Balance at End of Year (f)
1	Noncurrent Receivable - Post Retirement Benefits	26,588,134	122,850,900	143/253	119,292,734	30,146,300
2	Progress Payments/Plant Equipment	583,461	1,064,679	107/154	357,098	1,291,042
3	Directors' Endowment	66,003				66,003
4	Long Term PowerPlant Service Agreement (2007-2028)	403,338		107/553	65,406	337,932
5	Lease Buyout Costs (2009-2057)	4,108,865	5,468,783	588/880	4,108,865	5,468,783
6	Workers' Comp Reserve	800,540	62,779	925	153,722	709,597
7	Hydro Relicense	14,657,508	551,096	242	49,957	15,158,647
8	Other	(156,156)	21,996,159	131/242	22,026,969	(186,966)
47	Miscellaneous Work in Progress	17,058,253				21,269,540
48	Deferred Regulatroy Comm. Expenses (See pages 350 - 351)					
49	TOTAL	64,109,946				74,260,878

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	Net Operating Loss and Income Tax Credit Carryover	334,157,234	303,428,698
3	Toshiba Settlement	223,969,165	
4	Asset Retirement Obligation		
5	Remeasurement of Accumulated Deferred Income Taxes	112,508,971	109,323,696
6	Other Post Employment Benefits	38,396,984	34,449,295
7	Other	[(a)]378,139,439	[(b)]338,193,323
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,087,171,793	785,395,012
9	Gas		
10	Asset Retirement Obligation		
11	Other Post Employment Benefits	3,413,513	2,974,881
12	Environmental Remediation		
13	Incentive Compensation	419,426	552,302
14	Remeasurement of Accumulated Deferred Income Taxes		
15	Other	[(c)]21,058,593	[(d)]27,529,223
16	TOTAL Gas (Enter Total of lines 10 thru 15)	24,891,532	31,056,406
17.1	Other (Specify) Non Operating	[(e)]78,663,711	[(f)]250,011,155
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,190,727,036	1,066,462,573

Notes

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

Rate Refund due to Customers	$	133,980,246
Reg Liab EDIT Abandonment		104,543,451
Nuclear Decommissioning trust		56,646,628
Nuclear Unrecovered Plant		22,429,798
Fuel Impairment		22,318,102
Reg Asset - Decom ARO		7,010,885
Unamortized Investment Tax Credits		4,812,195
Short Term Incentive Plan		4,520,438
Reacquired Debt		3,699,218
Executive Deferred Compensation Plan		3,043,164
Early Retirement Programs		2,647,447
Payroll		2,377,863
Reserve for bad debts		2,211,536
Reserve for Injuries and Damages		1,944,726
Directors Fee		1,732,952
Nuclear Refueling Costs		1,286,060
Reg Liab - Customer Refund		1,124,323
All Other		1,810,407
Total	$	378,139,439

(b) Concept: AccumulatedDeferredIncomeTaxes

Rate Refund due to Customers	$	105,810,704
Regulatory Liability EDIT Abandonment		98,423,834
Nuclear Decommissioning trust		59,799,363
Nuclear Unrecovered Plant		15,962,362
Fuel Impairment		19,115,584
Unamortized Investment Tax Credits		4,403,857
Short Term Incentive Plan		6,031,905
Reacquired Debt		8,366,946
Executive Deferred Compensation Plan		6,113,262
Early Retirement Programs		2,647,447
Reserve for bad debts		85,094
Directors Fee		3,481,241
Nuclear Refueling Costs		3,507,528
Regulatory Liability - Customer Refund		1,124,323
All Other		3,319,873
Total	$	338,193,323

(c) Concept: AccumulatedDeferredIncomeTaxes

Reg Liab EDIT tax reform	$	18,590,505
Payroll		441,514
Unamortized Investment Tax Credits		336,256
Executive Deferred Compensation Plan		270,539
Early Retirement Programs		235,359
Rate Refund		203,686
Directors Fees		154,060
Reserve for Injuries and Damages		147,510
All Other		679,164
Total	$	21,058,593

(d) Concept: AccumulatedDeferredIncomeTaxes

Reg Liab EDIT tax reform	$	17,785,254
Environmental Cleanup		7,201,723
Payroll		300,546
Unamortized Investment Tax Credits		313,570
Executive Deferred Compensation Plan		504,133
Early Retirement Programs		235,359
Directors Fees		287,082
Reserve for Injuries and Damages		17,424
All Other		884,132
Total	$	27,529,223

(e) Concept: AccumulatedDeferredIncomeTaxes

Columbia Energy Center	$	33,150,186
Contingent Claims Reserve		30,461,249
Income Tax Credit Carryover		6,120,677
Charitable		4,116,750
Accrued Interest		3,258,062
Severance		522,232
Other Post Employee Benefits		294,737
Early Retirement Programs		20,322
Directors Endowment		13,302
All Other		706,194
Total	$	78,663,711

(f) Concept: AccumulatedDeferredIncomeTaxes

Toshiba Settlement	$	191,951,890
Columbia Energy Center		33,369,118
Contingent Claims Reserve		4,983,858
Income Tax Credit Carryover		12,524,002
Accrued Interest		4,559,335
Severance		426,807
Other Post Employee Benefits		294,737
Early Retirement Programs		20,322
Directors Endowment		32,305
All Other		1,848,781
Total	$	250,011,155

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Bal. Sheet (Total amount outstanding without reduction for amounts held by respondent) Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1	Common Stock (Account 201)									
2	[a] Common Stock	50,000,000			40,296,147	576,405,122				
6	Total	50,000,000			40,296,147	576,405,122				
7	Preferred Stock (Account 204)									
8	[b] Preferred Stock	20,000,000			[c] 1,000	100,000				
12	Total	20,000,000			1,000	100,000				
1	Capital Stock (Accounts 201 and 204) - Data Conversion									
2										
3										
4										
5	Total									

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: CapitalStockDescription
No par value
(b) Concept: CapitalStockDescription
No par value
(c) Concept: PreferredStockSharesOutstanding
These shares are held by SCANA Corporation and do not pay a dividend.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-03-24	Year/Period of Report End of: 2022/ Q4

Other Paid-in Capital

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with the balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

a. Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
b. Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
c. Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
d. Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	**Donations Received from Stockholders (Account 208)**	
2	Beginning Balance Amount	3,433,675,901
3.1	Equity advance from SCANA to DESC - Litigation Settlements (2022)	[a]72,872,333
4	Ending Balance Amount	3,506,548,234
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	0
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	0
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	0
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	0
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	9,751,822
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
16	Ending Balance Amount	9,751,822
17	**Historical Data - Other Paid in Capital**	
18	Beginning Balance Amount	3,443,427,723
19.1	Increases (Decreases) in Other Paid-In Capital	
19.2	Equity advance from SCANA to DESC - Litigation Settlements (2022)	72,872,333
20	Ending Balance Amount	
40	Total	3,516,300,056

FOOTNOTE DATA

(a) Concept: IncreasesDecreasesFromSalesOfDonationsReceivedFromStockholders

Amount represents the noncash contribution of Dominion Energy, Inc. stock, through the Company's parent (SCANA), to DESC during 2022 related to the settlement of litigation. The accounting entry was as follows:

Debit Account 186 - Miscellaneous Deferred Debits	$	72,872,333
Credit Account 208 - Donations Received from Shareholders	$	(72,872,333)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock Expense, no par value	4,335,379
22	TOTAL	4,335,379

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds, and in column (b) include the related account number.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received, and in column (b) include the related account number.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued, and in column (b) include the related account number.
5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a)principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (m). Explain in a footnote any difference between the total of column (m) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Related Account Number (b)	Principal Amount of Debt Issued (c)	Total Expense, Premium or Discount (d)	Total Expense (e)	Total Premium (f)	Total Discount (g)	Nominal Date of Issue (h)	Date of Maturity (i)	AMORTIZATION PERIOD Date From (j)	AMORTIZATION PERIOD Date To (k)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (l)	Interest for Year Amount (m)
1	Bonds (Account 221)												
2	First Mortgage Bonds:		[a]0										
3	6.625% Series, due 2032	221	300,000,000		2,928,187		2,397,000	01/31/2002	02/01/2032	01/31/2002	02/01/2032	300,000,000	19,875,000
4	4.50% Series, due 2064	221	375,000,000		3,900,440		4,803,750	[e]06/01/2014	06/01/2064	[f]06/01/2014	06/01/2064	52,051,000	2,342,295
5	5.25% Series, due 2035	221	100,000,000		1,032,840		1,821,000	03/08/2005	03/01/2035	03/08/2005	03/01/2035	100,000,000	5,250,000
6	5.30% Series, due 2033	221	300,000,000		2,678,847		579,000	05/21/2003	05/15/2033	05/21/2003	05/15/2033	300,000,000	15,900,000
7	5.80% Series, due 2033	221	200,000,000		1,785,478		646,000	01/23/2003	01/15/2033	01/23/2003	01/15/2033	200,000,000	11,600,000
8	6.25% Series, due 2036	221	125,000,000		1,240,777		421,250	06/27/2006	07/01/2036	06/27/2006	07/01/2036	125,000,000	7,812,500
9	6.05% Series, due 2038	221	250,000,000		2,611,037		242,500	01/14/2008	01/15/2038	01/14/2008	01/15/2038	250,000,000	15,212,725
10	6.05% Series, due 2038	221	110,000,000		962,500		5,365,800	06/24/2008	01/15/2038	06/24/2008	01/15/2038	110,000,000	6,473,500
11	4.35% Series, due 2042	221	250,000,000		2,559,708		207,500	01/30/2012	02/01/2042	01/30/2012	02/01/2042	59,424,000	2,584,944
12	4.35% Series, due 2042	221	250,000,000		2,559,709	(21,570,000)		07/13/2012	02/01/2042	07/13/2012	02/01/2042	59,424,000	2,584,944
13	6.05% Series, due 2038	221	175,000,000		1,916,924		728,000	03/17/2009	01/15/2038	03/17/2009	01/15/2038	175,000,000	10,681,275
14	5.50% Series, due 2039	221	150,000,000		1,517,157		1,179,000	12/09/2009	12/15/2039	12/09/2009	12/15/2039	150,000,000	8,250,000
15	5.45% Series, due 2041	221	250,000,000		2,187,500		917,500	01/27/2011	02/01/2041	01/27/2011	02/01/2041	250,000,000	13,625,000
16	5.45% Series, due 2041	221	100,000,000		1,361,577	(2,799,000)		05/24/2011	02/01/2041	05/24/2011	02/01/2041	100,000,000	5,450,000
17	4.60% Series, due 2043	221	400,000,000		4,234,911		2,000,000	06/14/2013	06/15/2043	06/14/2013	06/15/2043	400,000,000	18,400,000
18	5.10% Series, due 2065	221	500,000,000		5,325,812		4,035,000	05/22/2015	06/01/2065	05/22/2015	06/01/2065	500,000,000	25,500,000
19	4.10% Series, due 2046	221	425,000,000		3,718,750		875,500	06/13/2016	06/15/2046	06/13/2016	06/15/2046	49,894,000	2,045,654
20	4.25% Series, due 2028	221	400,000,000		2,600,000		1,000,000	08/17/2018	08/15/2028	08/17/2018	08/15/2028	53,251,000	2,263,168

21	2.3% Series, due 2031 SCPSC Order No. 2016-564 issued on August 18, 2016	221	400,000,000		3,097,830		248,000	11/29/2021	12/01/2031	11/29/2021	12/01/2031	400,000,000	9,200,000
22	Pollution Control Facilities Revenue Bonds:												
23	4% Industrial Revenue, due 2028	221	[b]39,480,000		426,014	(2,694,115)		01/15/2013	02/01/2028	01/15/2013	02/01/2028	39,480,000	1,579,200
24	3.625% Industrial Revenue, due 2033	221	[c]14,735,000		158,164		258,157	01/15/2013	02/01/2033	01/15/2013	02/01/2033	14,735,000	534,144
25	Variable Industrial Revenue, due 2038	221	[d]35,000,000		500,836			12/10/2008	12/01/2038	12/10/2008	12/01/2038	34,555,000	988,853
26	Amortization of Interest Rate Derivative Contracts:												
27	6.625% $300 Million due 2/1/2032	221								01/31/2002	02/01/2032		(47,641)
28	5.80% $200 Million due 1/15/2033	221								01/23/2003	01/15/2033		(7,339)
29	6.25% $125 Million due 7/1/2036	221								06/27/2006	07/01/2036		(273,654)
30	5.30% $300 Million due 5/21/2033	221								05/21/2003	05/15/2033		440,160
31	5.25% $100 Million due 3/1/2035	221								03/08/2005	03/01/2035		57,225
32	6.05% $250 Million due 1/15/2038	221								01/14/2008	01/15/2038		378,031
33	6.05% $110 Million due 1/15/2038	221								06/24/2008	01/15/2038		(13,534)
34	6.05% $175 Million due 1/15/2038	221								03/17/2009	01/15/2038		720,848
35	5.50% $150 Million due 12/15/2039	221								12/09/2009	12/15/2039		(530,495)
36	5.45% $250 Million due 2/1/2041	221								01/27/2011	02/01/2041		417,081
37	5.45% $100 Million due 2/1/2041	221								05/24/2011	02/01/2041		523,441
38	4.35% $250 Million due 2/01/2042	221								01/30/2012	02/01/2042		(72,200)
39	4.60% $75 Million due 6/14/2043	221								06/14/2013	06/15/2043		583,765
40	4.60% $75 Million due 6/14/2043	221								06/14/2013	06/15/2043		588,317
41	4.60% $90 Million due 6/14/2043	221								06/14/2013	06/15/2043		(352,393)
42	4.60% $80 Million due 6/14/2043	221								06/14/2013	06/15/2043		(315,063)
43	4.60% $80 Million due 6/14/2043	221								06/14/2013	06/15/2043		(307,961)
44	$35 Million SIFMA due 11/30/2038	221								12/01/2013	11/30/2038		61,355
45	4.50% $300 Million due 6/01/2064 and $75 Million due 6/1/2064	221								06/01/2014	06/01/2064		22,123
46	5.10% $500 Million due 6/01/2065	221								06/01/2015	06/01/2065		456,274
47	4.10% $425 Million due 6/15/2046	221								06/13/2016	06/15/2046		233,944
48	Subtotal		5,149,215,000		49,304,998	(27,063,115)	27,724,957					3,722,814,000	190,715,486
49	Reacquired Bonds (Account 222)												
50													
51													
52													
53	Subtotal												

54	Advances from Associated Companies (Account 223)												
55													
56													
57													
58	Subtotal												
59	Other Long Term Debt (Account 224)												
60	[(g)] Contract on Natural Gas Distribution System Fort Jackson Note due 2069	224	1,001,700									977,655	34,348
61	[(h)] Contract on Natural Gas Distribution System Acquired from Charleston AFB	224	424,844									132,348	6,616
62	Commitment Fees	224											210,722
63													[(j)] 0
64	[(i)] See Footnote												0
64	Subtotal		1,426,544									1,110,003	251,686
33	TOTAL		5,150,641,544									3,723,924,003	190,967,172

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: BondsPrincipalAmountIssued

With respect to unamortized amounts (premium, discount or expense) of debt redeemed, the Company follows the provisions set forth in General Instruction No. 17 of the Uniform System of Accounts. The Company records any unamortized amounts related to the redeemed debt to account 189 "Unamortized Loss on Reacquired Debt" or account 257 "Unamortized Gain on Reacquired Debt" as appropriate and amortizes this amount over the life of the new issue if refunded or over the remaining life of the original debt if not refunded.

In 2021 pursuant to the terms of the Comprehensive Settlement Agreement in DESC's 2020 Retail Electric Base Rate Case Proceeding (SCPSC 2020-125-E), DESC determined that $239.5 million of losses on reacquired debt previously carried in Account 189 - Unamortized Loss on Reacquired Debt were no longer probable of recovery. Accordingly, in 2021 DESC wrote-off this amount to Account 426.5 - Other Deductions in accordance with General Instruction 17(J) of the Uniform System of Accounts. DESC also determined that $2.1 million of gains on reacquired debt previously carried in Account 257 - Unamortized Gain on Reacquired Debt were no longer probable of return. Accordingly, in 2021 DESC wrote-off this amount to Account 421 - Miscellaneous Non-Operating Income in accordance with General Instruction 17(J) of the Uniform System of Accounts.

(b) Concept: BondsPrincipalAmountIssued

DESC issued $39,480,000 First Mortgage Bonds, Pledge Series, on January 15, 2013 at an interest rate of 4.000% with a maturity of February 1, 2028 to U. S. Bank National Association, as Trustee under the Bond Trust Indenture dated as of January 1, 2013, for the South Carolina Jobs-Economic Development Authority Industrial Revenue Bonds (South Carolina Electric & Gas Company Project) Series 2013.

(c) Concept: BondsPrincipalAmountIssued

DESC issued $14,735,000 First Mortgage Bonds, Pledge Series, on January 15, 2013 at an interest rate of 3.625% with a maturity of February 1, 2033 to U. S. Bank National Association, as Bond Trustee to the South Carolina Jobs-Economic Development Authority Industrial Revenue Bonds (South Carolina Electric & Gas Company Project) Series 2013.

(d) Concept: BondsPrincipalAmountIssued

DESC issued $35,000,000 First Mortgage Bonds, Pledge Series on December 10, 2008 at a floating rate with a maturity of December 1, 2038 to The Bank of New York Mellon Trust Company, N.A., as Bond Trustee to the South Carolina Jobs-Economic Development Authority Industrial Revenue Bonds (South Carolina Electric & Gas Company Project) Series 2008. Currently, there are $34,555,000 outstanding.

(e) Concept: NominalDateOfIssue

Debt was issued in two tranches, a tranche of $300,000,000 was issued June 1, 2014, and an additional tranche of $75,000,000 was issued on June 13, 2016

(f) Concept: AmortizationPeriodStartDate

Debt was issued in two tranches, a tranche of $300,000,000 was issued June 1, 2014, and an additional tranche of $75,000,000 was issued on June 13, 2016.

(g) Concept: ClassAndSeriesOfObligationCouponRateDescription

In 2018, the Company was awarded the contract for the privatization of the natural gas distribution system at Fort Jackson for a stated contract amount of $1,364,700. The Company submitted a revised purchase price proposal of $1,001,700 which was approved in February 2021 by the Department of defense through its contracting agent. On November 19, 2019, ownership of the system transferred to the Company, and the Company recorded assets totaling $1,001,700 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off

this long-term debt through applied billing credits over a period of 50 years. As of December 31, 2022, the outstanding amount related to this obligation was $977,655.

(h) Concept: ClassAndSeriesOfObligationCouponRateDescription

In 2007, the Company was awarded the contract for the privatization of the natural gas distribution system at the Charleston Air Force Base. On September 1, 2007, ownership of the system transferred to the Company and the Company recorded assets totaling $424,844 in Gas Utility Plant and an offsetting credit in Other Long-Term Debt. The Company will pay off this long-term debt through applied billing credits over a period of 20 years. As of December 31, 2022, the outstanding amount related to this obligation was $132,348.

(i) Concept: ClassAndSeriesOfObligationCouponRateDescription

The Company has authorization from the South Carolina Public Service Commission to issue up to $2.0 billion of First Mortgage Bonds (State Commission Order No. 2016-564). As of December 31, 2022, the Company had issued $840 million under such authorization.

(j) Concept: InterestExpenseOtherLongTermDebt

The interest expense of $12,052,249 included in account 430 - Interest on Debt to Associated Companies is related to short-term debt and therefore is not included in this schedule.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	482,587,046
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Tax Interest Capitalized	
6	Deferred Fuel	
9	Deductions Recorded on Books Not Deducted for Return	
10	Book Depreciation and Amortization	371,265,054
11	NND Regulatory Asset Amortization	138,405,300
12	Other	[a]155,198,228
14	Income Recorded on Books Not Included in Return	
15	Penalties	
16	Deferred Fuel	381,159,966
19	Deductions on Return Not Charged Against Book Income	
20	Tax Unrecovered Nuclear Project Costs	
21	Tax Depreciation and Amortization	505,550,529
22	Contingency Claims	100,839,906
23	Net Operating Loss	171,494,390
24	Reg Rate Refund	113,720,349
25	NND Regulatory Liability - Toshiba	128,376,704
26	Other	[b]55,194,318
27	Federal Tax Net Income	(308,880,534)
28	Show Computation of Tax:	
29	Tax @ 21%	(64,864,912)
30	Credits	(6,120,847)
31	Other	2,821,888

32	Other (Return to Provision)	(1,392,539)
33	Current Federal Income Tax Expense Recorded	(69,556,410)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

Total Net Book Income Tax (Including Investment Tax Credit)	$125,505,906
State taxes	4,043,338
Unrecovered Plant	8,924,788
Nuclear Outage Deferral	15,514,169
Meals and Lobbing	800,000
Restricted Stock	376,323
AFUDC	33,704
Total	$155,198,228

(b) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

Retirement Plan	$18,871,009
Storm Damage	4,108,567
Rate Case Expense	16,837,011
Vegetation Management	5,246,226
Payroll	5,650,056
Environmental Cleanup	4,481,446
All other	$3
Total	$55,194,318

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

TAXES ACCRUED, PREPAID AND CHARGES DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (g) and (h). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (g) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.
5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (d).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (i) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (l) through (o) how the taxes were distributed. Report in column (o) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 409.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (o) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

					BALANCE AT BEGINNING OF YEAR					BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED			
Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)	Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	Taxes Accrued (Account 236) (j)	Prepaid Taxes (Included in Account 165) (k)	Electric (Account 408.1, 409.1) (l)	Extraordinary Items (Account 409.3) (m)	Adjustment to Ret. Earnings (Account 439) (n)	Other (o)
1		[(a)] Other Taxes and Fees													
2	Other	Other Taxes			0	0				0	0				
3	**Subtotal Other Tax**				0	0				0	0				
4	County Property Tax	Property Tax			205,503,477		217,299,755	203,076,110	[(b)](963,856)	218,763,266		191,806,143			25,493,612
5	Municipal Property Tax	Property Tax			10,815,972		12,582,790	11,811,558		11,587,204		11,152,535			1,430,255
6	**Subtotal Property Tax**				216,319,449		229,882,545	214,887,668	(963,856)	230,350,470	0	202,958,678			26,923,867
7	Federal Income Taxes	Income Tax			0	0	(69,556,410)	(141,658,142)	[(c)](72,101,732)		0	(44,048,195)			(25,508,215)
8	State Income Taxes	Income Tax			35,997,478	0	68,716	9,230,957	[(d)]13,782,953	40,618,190	0	3,437,365			(3,368,649)
9	**Subtotal Income Tax**				35,997,478		(69,487,694)	(132,427,185)	(58,318,779)	40,618,190		(40,610,830)			(28,876,864)
10	Excise	Excise Tax			0	0	68	68		0	0	68			
11	**Subtotal Excise Tax**				0	0	68	68		0	0	68			
12	Franchise	Franchise Tax			0	0	14,382,953	600,000	[(e)](13,782,953)			12,385,600			1,997,353
13	**Subtotal Franchise Tax**				0	0	14,382,953	600,000	(13,782,953)			12,385,600			1,997,353
14	Electric Generation	Miscellaneous Other Tax			625,000	0	6,981,725	6,981,619	[(f)](106)	625,000		6,981,725			
15	**Subtotal Miscellaneous Other Tax**				625,000	0	6,981,725	6,981,619	(106)	625,000		6,981,725			
16	Other	Other Use Tax			1,054,349	0		11,258,059	[(g)]10,191,951	(11,759)					
17	**Subtotal Other Use Tax**				1,054,349	0		11,258,059	10,191,951	(11,759)					
18	FUTA	Payroll Tax			1,364	0	109,210	109,029		1,545		94,585			14,625
19	FICA	Payroll Tax			(120)	0	19,216,141	19,230,734		(14,713)		16,962,820			2,253,321

20	SUTA	Payroll Tax			2,976	0	117,304	113,706		6,574		101,598			15,706
21	Other Payroll	Payroll Tax			1,327,531	0	(1,349,117)	156,928	[(b)]995,765	817,251		(1,190,656)			(158,461)
22	**Subtotal Payroll Tax**				1,331,751		18,093,538	19,610,397	995,765	810,657		15,968,347			2,125,191
40	TOTAL				255,328,027		199,853,135	120,910,626	(61,877,978)	272,392,558	0	197,683,588			2,169,547

FOOTNOTE DATA

(a) Concept: TypeOfTax

Settlement activity of approximately $45 million in 2021 related to the SCDOR matter was recorded to FERC 242. In 2022, the Company made a decision to reclassify that activity to be consistent with the 2022 settlement activity, which is recorded to FERC 241. This reclassification did not impact customer rates.

(b) Concept: TaxAdjustments

Reclassified amount to accounts:

242 - Miscellaneous Current and Accrued Liabilities $ (963,856)

(c) Concept: TaxAdjustments

Reclassified amount to accounts:

146 Accounts Receivable Associated Company $ (72,101,732)

(d) Concept: TaxAdjustments

Reclassified amount to accounts:

Franchise Tax $13,782,953

(e) Concept: TaxAdjustments

Reclassified amount to accounts:

State Income Taxes $(13,782,953)

(f) Concept: TaxAdjustments

Reclassified amount to accounts:

242 - Miscellaneous Current and Accrued Liabilities $ (106)

(g) Concept: TaxAdjustments

Reclassified amount to accounts:

242 - Miscellaneous Current and Accrued Liabilities $10,191,951

(h) Concept: TaxAdjustments

Reclassified amount to accounts:

242 - Miscellaneous Current and Accrued Liabilities $995,765

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION (j)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)				
1	Electric Utility									
2	3%									
3	4%	94,941			411.4	7,451	[a](255)	87,235	58.4 Years	
4	7%									
5	10%	10,904,650			411.4	988,583	[b]10,137	9,926,204	58.4 Years	
6	8%	3,451,437			411.4	254,342		3,197,095	58.4 Years	
7	20%	24,131			411.4	2,346		21,785	58.4 Years	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	14,475,159				1,252,722	9,882	13,232,319		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
11	4%	4,441			411.4	475	[c]404	4,370	58.0 Years	
12	10%	318,347			411.4	7,999	[d](10,286)	300,062	58.0 Years	
13	8%	685,913			411.4	35,631	[e](1)	650,281	58.0 Years	
14	20%	2,762			411.4	145	[f]1	2,618	58.0 Years	
15	Gas Utility									
16	Total Gas	1,011,463				44,250	(9,882)	957,331		
47	OTHER TOTAL									
48	GRAND TOTAL	15,486,622				1,296,972		14,189,650		

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FOOTNOTE DATA

(a) Concept: AccumulatedDeferredInvestmentTaxCreditsAdjustments
It's a reclassification between the electric and gas utility (Please see the total on line 8 and 16)
(b) Concept: AccumulatedDeferredInvestmentTaxCreditsAdjustments
It's a reclassification between the electric and gas utility (Please see the total on line 8 and 16)
(c) Concept: AccumulatedDeferredInvestmentTaxCreditsAdjustments
It's a reclassification between the electric and gas utility (Please see the total on line 8 and 16)
(d) Concept: AccumulatedDeferredInvestmentTaxCreditsAdjustments
It's a reclassification between the electric and gas utility (Please see the total on line 8 and 16)
(e) Concept: AccumulatedDeferredInvestmentTaxCreditsAdjustments
It's a reclassification between the electric and gas utility (Please see the total on line 8 and 16)
(f) Concept: AccumulatedDeferredInvestmentTaxCreditsAdjustments
It's a reclassification between the electric and gas utility (Please see the total on line 8 and 16)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Gas Environmental Remediation	19,337,486	131/182.3	19,337,486	20,060,000	20,060,000
2	Other Environmental Remediation	600,000			850,486	1,450,486
3	Long-Term Disability	127,646				127,646
4	Accrued Liability - Director's Endowment Program	(177,362)			177,362	
5	Santee River Basin Accord	733,998	131	58,070		675,928
6	Municipal Nonstandard Service Fund Matching Obligation	4,632,949	186	1,652,846		2,980,103
7	SRS Substation	1,323,900	456	96,284		1,227,616
8	Interconnection Study Deposits	2,045,169	243/456	2,189,105	6,153,801	6,009,865
9	CIAC Obligations	15,780,042	107	1,403,641	1,349,879	15,726,280
10	Noncontrolling Interest - SCFC	5,709,895				5,709,895
11	FIN 48 Penalty	3,502,106				3,502,106
12	Other	2,149,438	421/440	383,459	1,463,559	3,229,538
47	TOTAL	55,765,267		25,120,891	30,055,087	60,699,463

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	10,577,600		295,385							10,282,215
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	10,577,600		295,385							10,282,215
9	Gas										
10	Defense Facilities										
11	Pollution Control Facilities										
12	Other										
12.1	Other (provide details in footnote):										
15	TOTAL Gas (Enter Total of lines 10 thru 14)										
16	Other										
16.1	Other										
16.2	Other										
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	10,577,600		295,385							10,282,215
18	Classification of TOTAL										
19	Federal Income Tax	9,194,900		256,765							8,938,135
20	State Income Tax	1,382,700		38,620							1,344,080
21	Local Income Tax										

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Use footnotes as required.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)	CHANGES DURING YEAR: Amounts Debited to Account 410.2 (e)	CHANGES DURING YEAR: Amounts Credited to Account 411.2 (f)	ADJUSTMENTS: Debits: Account Credited (g)	ADJUSTMENTS: Debits: Amount (h)	ADJUSTMENTS: Credits: Account Debited (i)	ADJUSTMENTS: Credits: Amount (j)	Balance at End of Year (k)
1	Account 282										
2	Electric	1,088,556,436	41,442,569	9,747,216					182.3/254		1,120,251,789
3	Gas	121,660,853	3,024,929						182.3/254	(180,258)	124,505,524
4	Other (Specify)	6,108,583			145,665	745,150	190/282	(271,033)			5,780,131
5	Total (Total of lines 2 thru 4)	1,216,325,872	44,467,498	9,747,216	145,665	745,150		(271,033)		(180,258)	1,250,537,444
6											
7											
8											
9	TOTAL Account 282 (Total of Lines 5 thru 8)	1,216,325,872	44,467,498	9,747,216	145,665	745,150		(271,033)		(180,258)	1,250,537,444
10	Classification of TOTAL										
11	Federal Income Tax	1,000,413,458	31,518,020	7,943,950	145,665	51,505		(216,717)		(106,817)	1,024,191,588
12	State Income Tax	215,912,414	12,949,478	1,803,266		693,645		(54,316)		(73,441)	226,345,856
13	Local Income Tax										

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.
3. Provide in the space below explanations for Page 276. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

			CHANGES DURING YEAR				ADJUSTMENTS				
							Debits		Credits		
Line No.	Account (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)	Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)
1	Account 283										
2	Electric										
3	Unrecovered Nuclear Proj Costs	603,362,555	47,726,760	81,784,660							569,304,655
4	Regulatory Asset - ARO										
5	Employee Benefit Plan Costs										
6	Unrecovered Plant Canadys	18,378,656	201,586	4,991,653							13,588,589
7	Prepayments	12,207,393	56,525	2,283							12,261,635
8	[a] All Other	162,570,964	144,107,343	13,136,718			190/282/283	12,105,768			281,435,821
9	TOTAL Electric (Total of lines 3 thru 8)	796,519,568	192,092,214	99,915,314				12,105,768			876,590,700
10	Gas										
11	Employee Benefit Plan Costs										
12	Regulatory Asset - ARO										
13	Deferred Gas Costs	1,616,597	8,164,837	329,734							9,451,700
14	Pension Plan Income	3,628,799	1,007,132	314,800							4,321,131
15	Prepayments	2,359,689	3,419	84,673							2,278,435
16	[b] All Other	16,165,227	5,070,429	12,284,084					190/282/283	7,208,535	16,160,107
17	TOTAL Gas (Total of lines 11 thru 16)	23,770,312	14,245,817	13,013,291						7,208,535	32,211,373
18	TOTAL Other	[c]313,325			142,762	5,747					450,340
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	820,603,205	206,338,031	112,928,605	142,762	5,747		12,105,768		7,208,535	909,252,413
20	Classification of TOTAL										
21	Federal Income Tax	656,176,007	171,406,825	92,599,209	115,398	5,747	190/282/283	13,782,518	190/282/283	5,736,157	727,046,913
22	State Income Tax	164,427,198	34,931,206	20,329,396	27,364		190/282/283	(1,676,750)	190/282/283	1,472,378	182,205,500
23	Local Income Tax										

NOTES

FOOTNOTE DATA

(a) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Pension plan income	$ 40,818,636	$ 18,271,890	$ 737,903	$ —	$ 58,352,623
Deferred fuel costs	29,906,271	90,936,754	3,672,446	—	117,170,579
Demand Side Management Costs	18,838,858	87,757	2,173,034	—	16,753,581
Cyber Security Costs	8,222,685	242	5,983	—	8,216,944
Fukushima Compliance	1,122,750	1,575	39,000	—	1,085,325
Deferred VCS Costs	986,746	1,930	47,792	—	940,884
Regulatory Asset Deferred Capacity	939,646	19,622	485,880	—	473,388
Grants	673,650	1,050	26,000	—	648,700
Insurance, Injuries and Damages	—	—	—	(217,159)	217,159
Payroll	—	—	—	(300,546)	300,546
Decommissioning	—	—	—	(7,151,372)	7,151,372
Reg Liab - Vegetation Management	—	1,364,310	62,299	—	1,302,011
Reg Liab State EDIT Property	5,951,481	455,806	—	413,320	5,993,967
Reg Asset - DER Costs	1,123,340	630,764	25,473	—	1,728,631
Reg Asset - Major Maintenance	2,632,706	1,122	27,793	—	2,606,035
Reg Asset - Pollution Control	6,916,429	14,118	349,595	—	6,580,952
Reg Asset - Storm Damage	11,225,454	1,096,611	745,983	—	11,576,082
Reg Liab EDIT NOL	31,793,484	22,808,756	—	30,391,414	24,210,826
All Other	1,418,828	8,415,036	4,737,537	(11,029,889)	16,126,216
Total	$ 162,570,964	$ 144,107,343	$ 13,136,718	$ 12,105,768	$ 281,435,821

(b) Concept: DescriptionOfAccumulatedDeferredIncomeTaxOther

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Reacquired debt	$ 10,246,768	$ 771,261	$ 31,147	—	$ 10,986,882
Employee Costs	—	3,757	—		3,757
Gas Water Heater	—	1,755,308	70,887	—	1,684,421
Environmental Cleanup Reserve	3,055,686	1,643,906	11,901,316	7,201,724	—
Gas Pipeline Integrity	2,061,450	368,674	14,889	—	2,415,235
Gas WNA Cap	426,683	9,883	244,734	—	191,832
Reg Liab State EDIT Property	308,189	(5,110)	—	6,811	309,890
Reg Asset - Gas ERTS	66,451	522,750	21,111	—	568,090
Total	$ 16,165,227	$ 5,070,429	$ 12,284,084	7,208,535	$ 16,160,107

(c) Concept: AccumulatedDeferredIncomeTaxesOther

	Balance at Beg. of Year	Amt. Debited Acct. 410.1	Amt. Credited Acct.411.1	Adjust.	Balance at End of Year
Pension plan income	$ 313,325	142,292	$ 5,747	—	$ 449,870
Employee Benefits	—	470	—	—	470
Total	$ 313,325	$ 142,762	$ 5,747	—	$ 450,340

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Accumulated Deferred Income Tax Credits	5,148,451	409.1	435,777	4,753	4,717,427
2	[a] Nuclear Refueling Accrual		524/528	1,476,558	16,356,622	14,880,064
3	NOX Emission Allowance Proceeds	1,042				1,042
4	[b] Interest Rate Derivatives (3/2009-6/2043)	69,155,346	427	7,576,181	6,565,357	68,144,522
5	[c] Solar PPAs MTM Gains	148,135,913	175	935,435,630	1,038,378,529	251,078,812
6	[d] Demand Side Management Carrying Costs	814,642	182.3	783,562	261,134	292,214
7	SO2 Emission Allowance Proceeds	1,183				1,183
8	[e] Overcollected Electric Pension Expense	1,742,064	926	3,333,458	2,815,300	1,223,906
9	[f] Monetization-Toshiba Settlement (2/2019-1/2039)	897,672,003	[t] see footnote	128,376,704		769,295,299
10	[g] Excess Deferred Tax Liabilities - Electric	867,018,468	[u] see footnote	35,042,867		831,975,601
11	[h] Excess Deferred Tax Liabilities - Gas	77,419,135	410	6,245,812		71,173,323
12	[i] Amortization Excess Deferred Tax Liabilities - Gas (11/2021-10/2022)	30,262	481	30,709	447	
13	[j] Customer Refunds Merger Approval Order - Electric	537,808,000	[v] see footnote	113,717,000		424,091,000
14	[k] Customer Refunds Merger Approval Order - Gas (11/2021-10/2022)	3,349	[w] see footnote	3,349		
15	[l] WEC Reimbursement Proceeds	4,557,263	182.3	4,585,758	28,495	
16	[m] Deferred Gain on Sale of Turbine Generator and Associated Equipment (9/2021-8/2023)	812,500	407.4	487,500		325,000
17	[n] Revenue Subject to Refund - Tax Reform Electric Residual Balance (9/2021-9/2024)	1,311,014	407.4	485,901		825,113
18	[o] Amortized Excess Deferred Tax Liabilities from GENCO (9/2021-6/2026)	6,011,244	555	1,352,364		4,658,880
19	Renewable Energy Credits	3,268,602	174	1,417,900	719,618	2,570,320
20	[p] Decommissioning Asset Ret. Obligation	22,888,469	182.3	22,888,469		
21	[q] Hardeeville Retirement		108	65,570	1,144,145	1,078,575

22	[r] Environmental Remediation Costs	133,956	573/592	1,202,030	1,420,000	351,926
23	Amt. Overcollected - Vegetation Mgmt Accrual	27,743	182.3	2,324,723	2,296,980	
24	[s] Unprotected Plant EDIT Decrement Rider	89,898,991	190/409.1	25,921,587		63,977,404
41	TOTAL	2,733,859,640		1,293,189,409	1,069,991,380	2,510,661,611

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2012-218-E

SCPSC Docket No. 2020-172-E

SCPSC Docket No. 2020-125-E

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Activity is associated with the amortization of settlement amounts over the life of the related debt issuances.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Represents the mark to market gains associated with embedded derivatives of Solar PPAs that contain minimum production guarantees and not probable of physical settlement.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2013-50-E
SCPSC Docket No. 2013-208-E
SCPSC Docket No. 2014-44-E
SCPSC Docket No. 2015-45-E
SCPSC Docket No. 2016-40-E
SCPSC Docket No. 2017-35-E
SCPSC Docket No. 2018-42-E
SCPSC Docket No. 2019-57-E
SCPSC Docket No. 2020-41-E

SCPSC Docket No. 2021-34-E

SCPSC Docket No. 2022-52-E

SCPSC Docket No. 2023-42-E

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2012-218-E
SCPSC Docket No. 2022-74-E

In the dockets referenced above, the SCPSC authorized the recovery of current pension expense related to retail electric operations through a rate rider mechanism. Any differences between actual pension expense and amounts recovered through the rider are deferred as a regulatory asset (under-recovered) or regulatory liability (over-recovered) as appropriate.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Represents net proceeds received under or arising from the monetization of the Settlement Agreement dated as of July 27, 2017 with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E, the SCPSC ordered $1.032 billion to be credited to customers over twenty years beginning in February 2019.

In March 2022 in SCPSC Docket No. 2022-2-E, DESC applied approximately $61.3 million of this regulatory liability as a reduction to its retail electric undercollected base fuel cost balance.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The FERC jurisdictional transmission portion of these amounts was included in a compliance filing for Order No. 864 in FERC Docket No. ER20-1836. This matter is pending.

SCPSC Docket No. 2017-381-A

Amounts related to plant-related temporary differences are being amortized using the average rate assumption method (ARAM). Under ARAM, the excess deferred tax liabilities will reverse at the weighted average rate at which the deferred taxes were built over the remaining book life of the property to which those deferred taxes relate. These reversal periods average fifty years.

For non-plant related excess deferred tax liabilities, the balances will reverse over 5 years, or in the case of Nuclear Project-related excess deferred tax liabilities, twenty years.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Amounts related to plant-related temporary differences are being amortized using the average rate assumption method (ARAM). Under ARAM, the excess deferred tax liabilities will reverse at the weighted average rate at which the deferred taxes were built over the remaining book life of the property to which those deferred taxes relate. These reversal periods average fifty years.

For non-plant related excess deferred tax liabilities, the balances will reverse over 5 years.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2021-6-G

Pursuant to SCPSC Docket No. 2019-6-G, this amount was amortized through October 2020. Pursuant to SCPSC Docket No. 2021-6-G, amortization of the remaining balance commenced in November 2021 and concluded in 2022.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2017-370-E

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2017-370-E

SCPSC Docket No. 2021-6-G

By Order No. 2018-804, issued in Docket No. 2017-370-E, the SCPSC ordered the refund of $2.45 million of previous collections from gas customers. The refund was to be provided over three years (2019-2021) in annual tranches in the first quarter of each year. The third and final was provided in the first quarter of 2021. Since the refund was a volumetric calculation, a residual balance remained to be refunded. In SCPSC Docket No. 2021-6-G, the SCPSC authorized amortization over approximately one year beginning in November 2021 and was completed in 2022.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

DESC received an initial payment of $2,930,425 in April 2019 and a subsequent payment of $1,472,581 in July 2019 representing its 55% share of proceeds received from W Wind Down Company LLC (Company established to administer Westinghouse Electric Company LLC's bankruptcy obligations) per the terms of the Interim Assessment Agreement and with the approval of the Bankruptcy Court. This amount, plus accrued carrying cost of $182,752, has been recorded as a regulatory liability.

In March 2022 in SCPSC Docket No. 2022-2-E, DESC applied these proceeds as a reduction to its retail electric undercollected base fuel cost balance.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2020-125-E

Deferred gain related to sale of an electric power generator, a 13.8/115kV generator step-up transformer and associated equipment to Kapstone Charleston Kraft, LLC. The FERC authorized the clearing of the gain from Account 102 - Electric Plant Purchased or Sold to Account 254 - Other Regulatory Liabilities via a letter order dated July 2, 2019 issued in Docket No. AC19-145-000.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2020-125-E

By Order No. 2018-804 issued in Docket No. 2017-370-E, the SCPSC ordered the refund of amounts collected from customers and reserved for refund related to the change in the corporate federal tax rate. The Company provided the refund in accordance with the order in February 2019. However, since the refund was a volumetric calculation, a residual balance is being refunded pursuant to the SCPSC Docket above.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2020-125-E

By order dated April 28, 2020, the FERC authorized modifications to South Carolina Generating Company, Inc.'s (GENCO) formula rate to provide for the pass through of GENCO's amortized Excess Deferred Tax Liabilities to DESC.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2003-84-E

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

By Order No. 2022-517, dated July 21, 2022, the Public Service Commission of South Carolina granted Dominion Energy South Carolina, Inc.'s petition in SCPSC Docket No. 2022-107-E to reclassify its net credit balance

carrying value related to the retirement of its Hardeeville simple cycle combustion turbine to a regulatory liability account.

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

SCPSC Docket No. 2012-218-E

(s) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The FERC jurisdictional transmission portion of these amounts was included in a compliance filing for Order No. 864 in FERC Docket No. ER20-1836. This matter is pending.

SCPSC Docket No. 2020-125-E

In connection with the comprehensive settlement agreement approved by the SCPSC (Docket No. 2020-125-E) in DESC's retail electric base rate case, unprotected plant-related excess deferred tax liabilities will be returned to retail customers through a volumetric decrement rate rider which began in September 2021. Amortization will be matched with the rider decrements, with certain portions of the amortization affecting the OATT formula rate.

(t) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

131 / 182.3 / 440 / 442 / 444 / 445

(u) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

190 / 254 / 282 / 283

(v) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

440 / 442 / 444 / 445

(w) Concept: OtherRegulatoryLiabilitiesDescriptionOfCreditedAccountNumberForDebitAdjustment

142 / 480 / 481

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Electric Operating Revenues

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.
6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See page 108, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)	MEGAWATT HOURS SOLD Year to Date Quarterly/Annual (d)	MEGAWATT HOURS SOLD Amount Previous year (no Quarterly) (e)	AVG.NO. CUSTOMERS PER MONTH Current Year (no Quarterly) (f)	AVG.NO. CUSTOMERS PER MONTH Previous Year (no Quarterly) (g)
1	Sales of Electricity						
2	(440) Residential Sales	1,374,324,866	1,210,152,980	8,485,891	8,232,408	[l] 669,251	659,585
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	968,218,949	833,900,373	7,186,928	7,069,472	[m] 102,179	100,827
5	Large (or Ind.) (See Instr. 4)	532,789,860	423,936,519	5,568,616	5,538,657	[n] 764	770
6	(444) Public Street and Highway Lighting	18,309,110	15,681,719	74,957	75,196	[o] 1,050	1,038
7	(445) Other Sales to Public Authorities	56,831,542	47,868,783	504,003	495,509	[p] 3,751	3,745
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	[a] 2,950,474,327	[f] 2,531,540,374	[i] [j] 21,820,395	[k] 21,411,242	776,995	765,965
11	(447) Sales for Resale	[b] 87,419,199	54,775,495	1,159,293	1,043,100	6	4
12	TOTAL Sales of Electricity	3,037,893,526	2,586,315,869	22,979,688	22,454,342	777,001	765,969
13	(Less) (449.1) Provision for Rate Refunds						
14	TOTAL Revenues Before Prov. for Refunds	3,037,893,526	2,586,315,869	22,979,688	22,454,342	777,001	765,969
15	Other Operating Revenues						
16	(450) Forfeited Discounts	7,854,221	6,741,972				
17	(451) Miscellaneous Service Revenues	[c] 4,829,245	[g] 5,551,297				
18	(453) Sales of Water and Water Power	585,775	396,086				
19	(454) Rent from Electric Property	29,919,061	21,641,279				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[d] 8,782,882	[h] 3,531,802				

22	(456.1) Revenues from Transmission of Electricity of Others	[e]14,686,506	13,404,672				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	66,657,690	51,267,108				
27	TOTAL Electric Operating Revenues	3,104,551,216	2,637,582,977				

Line12, column (b) includes $ 127,284,821 of unbilled revenues.
Line12, column (d) includes 1,093,657 MWH relating to unbilled revenues

FOOTNOTE DATA

(a) Concept: SalesToUltimateConsumers

Includes the following amounts under/(over)-collected pursuant to the respondent's fuel adjustment clause:

Residential	$	153,728,402
Commercial		135,785,130
Industrial		102,889,567
Street Lighting		1,113,199
Other Public Authorities		9,442,941
	$	402,959,239

Includes Unmetered Sales Revenue as follows:

Residential	$18,869,170
Commercial/Industrial	29,427,948
Street Lighting	14,392,623
Other Public Authorities	100,499
	$62,790,240

In accordance with the SCPSC's Merger Approval Order, in January 2019 the Company established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which will be credited to customers over approximately 11 years beginning in February 2019.

(b) Concept: SalesForResale

This amount does not include $4,757 in revenue from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023. This revenue is reflective of 2,541 MWH.

(c) Concept: MiscellaneousServiceRevenues

Includes $722,758 of reconnect and lighting disconnect charges.

Includes $2,960,794 of transmission maintenance fee revenue.

Includes $1,108,305 of returned check fees.

(d) Concept: OtherElectricRevenue

Includes $5,661,939 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $2,261,036 of Timber Sales.

Includes $256,012 in Recreational Facilities Charge

(e) Concept: RevenuesFromTransmissionOfElectricityOfOthers

This amount does not include $732 for revenue from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023. This revenue is reflective of 763 MWH.

(f) Concept: SalesToUltimateConsumers

Includes the following amounts under/(over)-collected pursuant to the respondent's fuel adjustment clause:

Residential	$	68,305,224
Commercial		55,887,958
Industrial		42,663,131
Street Lighting		591,275
Other Public Authorities		3,923,921
	$	171,371,509

Includes Unmetered Sales Revenue as follows:

Residential	$18,559,537
Commercial/Industrial	28,956,956
Street Lighting	14,005,178
Other Public Authorities	95,342
	$61,617,013

In accordance with the SCPSC's Merger Approval Order, in January 2019 the Company established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which will be credited to customers over approximately 11 years beginning in February 2019.

(g) Concept: MiscellaneousServiceRevenues

Includes $1,754,252 of reconnect and lighting disconnect charges.

Includes $2,866,723 of transmission maintenance fee revenue.

Includes $810,261 of returned check fees.

Includes $120,061 of Investigative Charges.

(h) Concept: OtherElectricRevenue

Includes $1,406,941 associated with municipal Franchise Fees pursuant to SCPSC Docket No. 2008-2-E.

Includes $259,304 of Telecommunication Tower Rent Revenue.

Includes $1,114,140 of Timber Sales

(i) Concept: MegawattHoursSoldSalesToUltimateConsumers

Sales to Ultimate Customers includes 8 megawatt hours of Energy Furnished Without Charge. This was done to be in line with the Taxonomy provided by FERC to ensure the total here agrees with page 300-301, Line 10 Column D.

(j) Concept: MegawattHoursSoldSalesToUltimateConsumers

Includes Unmetered MWH Sales as follows:

Residential	75,188
Commercial/Industrial	141,502
Street Lighting	61,046
Other Public Authorities	699
	278,435

(k) Concept: MegawattHoursSoldSalesToUltimateConsumers

Includes Unmetered MWH Sales as follows:

Residential	75,966
Commercial/Industrial	143,564
Street Lighting	68,114
Other Public Authorities	699
	288,343

(l) Concept: AverageNumberOfCustomersPerMonthResidentialSales

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(m) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercial

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(n) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrial

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(o) Concept: AverageNumberOfCustomersPerMonthPublicStreetAndHighwayLighting

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(p) Concept: AverageNumberOfCustomersPerMonthOtherSalesToPublicAuthorities

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales by Rate					
2	1	308,001	44,093,290		15,050	0.1432
3	2	29,779	5,600,742		1,700	0.1881
4	5	971	143,856		14,712	0.1482
5	6	453,733	65,110,147		14,586	0.1435
6	7	772	89,637		64,333.000	0.1161
7	8	7,518,446	1,123,407,282		12,810	0.1494
8	E1N	4,762	874,437		9,105	0.1836
9	E2N	42	20,199		553	0.4809
10	E5N	48	7,807		12,000	0.1626
11	E6N	6,663	1,260,184		8,246	0.1891
12	E8N	79,155	15,913,479		7,418	0.2010
13	M1N		(12)			0.0000
14	M2N		0			0.0000
15	M5N		0			0.0000
16	M6N		(39)			0.0000
17	M8N	(2)	(231)			0.1155
18	5SC	7,215	1,115,233		93	0.1546
19	Special (A)	76,306	21,780,155		354	0.2854
20	Current Year Customer Refund Amount		[a]60,866,000			
21	Toshiba Guarantee Amortization		[b]34,042,700			
41	TOTAL Billed Residential Sales	7,921,788	1,301,187,645			
42	TOTAL Unbilled Rev. (See Instr. 6)	564,103	73,137,221			
43	TOTAL	8,485,891	1,374,324,866	[c]669,251	[d]8,830	0.1620

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: ResidentialSalesBilled

Reflects customer refund regulatory liability amortization.

(b) Concept: ResidentialSalesBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2022.

(c) Concept: AverageNumberOfCustomersPerMonthResidentialSales

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerResidentialSales

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Commercial Sales by Rate					
2	3	1,313	167,201		87,533	0.1273
3	9	2,669,141	408,609,235		31,871	0.1531
4	10	3,743	1,133,385		1,399	0.3028
5	11	13,255	1,658,126		40,167	0.1251
6	12	146,018	18,913,737		40,538	0.1295
7	14	18,829	2,910,248		10,766	0.1546
8	16	74,290	11,283,982		16,961	0.1519
9	20	1,755,302	199,300,460		889,661	0.1135
10	21	116,284	14,645,315		260,726	0.1259
11	22	422,760	54,986,445		270,134	0.1301
12	23	223,570	18,992,465		55,892,500	0.0850
13	24	1,593,896	148,095,678		9,778,503	0.0929
14	28	1,784	253,055		89,200	0.1418
15	E9N	10,085	(1,017,948)		72,554	(0.1009)
16	Special (A)	136,658	33,754,565		5,211	0.2470
17	Current Year Customer Refund Amortization		[a]33,964,000			
18	Toshiba Guarantee Amortization		[b]20,569,000			
41	TOTAL Billed Small or Commercial	6,818,806	928,263,378			
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	368,122	39,955,571			
43	TOTAL Small or Commercial	7,186,928	968,218,949	[c]102,179	[d]56,576	0.1347

FERC FORM NO. 1 (ED. 12-95)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: SmallOrCommercialSalesElectricOperatingRevenueBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2022.

(c) Concept: AverageNumberOfCustomersPerMonthSmallOrCommercial

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerSmallOrCommercialSales

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Industrial Sales by Rate					
2	9	138,192	21,750,090		254,029	0.1574
3	16	211	29,674		105,500	0.1406
4	20	80,483	10,147,946		1,518,547	0.1261
5	23	3,538,722	310,844,751		27,646,266	0.0878
6	24	69,150	7,487,531		6,915,000	0.1083
7	27	673,954	56,068,875		96,279,143	0.0832
8	60	1,061,514	97,174,715		212,302,800	0.0915
9	E9N	1,729	540,206		247,000	0.3124
10	Special (A)	4,661	860,672		13,629	0.1847
11	Current Yr. Customer Refund Amortization		[a]16,750,000			
12	Toshiba Guarantee Amortization		[b]11,135,400			
41	TOTAL Billed Large (or Ind.) Sales	5,434,754	522,195,056			
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	133,862	10,594,804			
43	TOTAL Large (or Ind.)	5,568,616	532,789,860	[c]764	[d]5,071,599	0.0957

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: LargeOrIndustrialSalesElectricOperatingRevenueBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2022.

(c) Concept: AverageNumberOfCustomersPerMonthLargeOrIndustrial

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerLargeOrIndustrialSales

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2						
3						
4						
5						
6						
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29						
30						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed Commercial and Industrial Sales					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL					

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Public Street and Highway Lighting Sales by Rate					
2	3	1,465	203,507		14,226	0.1389
3	9	1,590	392,089		3,375	0.2466
4	13	4,645	641,652		10,703	0.1381
5	Special (A)	67,257	17,001,462		52,097	0.2528
6	Current Year Customer Refund Amortization		[a]57,000			
7	Toshiba Guarantee Amortization		[b]13,400			
41	TOTAL Billed Public Street and Highway Lighting	67,527	16,532,080			
42	TOTAL Unbilled Rev. (See Instr. 6)	7,430	1,777,030			
43	TOTAL	74,957	18,309,110	[c]1,050	[d]32,604	0.2443

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PublicStreetAndHighwayLightingBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: PublicStreetAndHighwayLightingBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2022.

(c) Concept: AverageNumberOfCustomersPerMonthPublicStreetAndHighwayLighting

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerPublicStreetAndHighwayLighting

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Other Sales to Public Authorities					
2	3	165,395	22,372,207		46,841	0.1353
3	9	733	146,503		7,477	0.1999
4	20	8,038	901,442		1,148,351	0.1121
5	21	210	27,617		210,228	0.1315
6	65	63,239	5,461,130		3,161,954	0.0864
7	66	265,687	24,480,459		7,591,076	0.0921
8	Special (A)	701	122,684		9,733	0.1750
9	Current Year Customer Refund Amortization		[a]2,080,000			
10	Toshiba Guarantee Amortization		[b]1,239,500			
41	TOTAL Billed Other Sales to Public Authorities	483,864	55,011,347			
42	TOTAL Unbilled Rev. (See Instr. 6)	20,139	1,820,195			
43	TOTAL	504,003	56,831,542	[c]3,751	[d]133,901	0.1128

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: OtherSalesToPublicAuthoritiesBilled

Reflects customer refund regulatory liability amortization..

(b) Concept: OtherSalesToPublicAuthoritiesBilled

As identified on the Other Regulatory Liabilities schedule on page 278 the Company established a regulatory liability for the net proceeds received under or arising from the monetization of the settlement agreement with Toshiba Corporation. By Order No. 2018-804 issued in Docket No. 2017-370-E the SCPSC ordered $1.032 billion to be credited to customers over 20 years beginning in February 2019. The amount in column c represents the amortization of that regulatory liability during 2022.

(c) Concept: AverageNumberOfCustomersPerMonthOtherSalesToPublicAuthorities

The average number of customers reported on page 300 column f excludes unmetered accounts. In order to ensure the average number of customers on page 304 column d agrees to page 300 column f, in accordance with the taxonomy provided by FERC, the Company is reporting the average number of customers on page 304 column d by class and not by individual rate schedule.

(d) Concept: KilowattHoursOfSalesPerCustomerOtherSalesToPublicAuthorities

Average KWh of Sales Per Customer shown here are based on average number of customers including unmetered accounts.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Page 310.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
41	TOTAL Billed - All Accounts	20,726,739	2,823,189,506			
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	1,093,656	127,284,821			
43	TOTAL - All Accounts	21,820,395	2,950,474,327			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.

   SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.

   LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

   OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

   AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (g) through (k).
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	ACTUAL DEMAND (MW)		Megawatt Hours Sold (g)	REVENUE			Total ($) (h+i+j) (k)
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	City of Orangeburg	RQ	[(k)] footnote	119	139	134	766,516	10,470,243	30,961,401		41,431,644
2	Town of Winnsboro	RQ	[(l)] footnote	11	11	11	58,562	1,342,280	2,471,444		3,813,724
3	Carolina Power Partners, LLC	[(a)] OS	[(m)] footnote				4,200		311,400		311,400
4	Duke Energy Carolinas, LLC	[(b)] OS	[(n)] footnote				288		13,616		13,616
5	Exelon Generation Company, LLC	[(c)] OS	[(o)] footnote				62,724		4,480,006		4,480,006
6	Macquarie Energy LLC	[(d)] OS	[(p)] footnote				111,683		9,736,987		9,736,987
7	North Carolina Electric Membership Corporation	[(e)] OS	[(q)] footnote				1,644		119,767		119,767
8	Oglethorpe Power Corporation	[(f)] OS	[(r)] footnote				12		645		645
9	South Carolina Public Service Authority -- Emergency	[(g)] OS	[(s)] footnote				493		624,107		624,107

10	Southern Company Services, Inc.	OS[h]	footnote[t]				10,756		1,159,750		1,159,750
11	Tennessee Valley Authority	OS[i]	footnote[u]				61		2,644		2,644
12	The Energy Authority, Inc	OS[j]	footnote[v]				142,354		13,414,058		13,414,058
13	Wholesale Fuel Over/Under Collection									12,310,851	12,310,851
14	Transmission Revenue included in Energy Charges Column (i)										
15	Subtotal - RQ						825,078	11,812,523	33,432,845		45,245,368
16	Subtotal-Non-RQ						334,215		29,862,980[w]	12,310,851	42,173,831
17	Total						1,159,293	11,812,523	63,295,825	12,310,851	87,419,199[x]

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(b) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(c) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(d) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(e) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(f) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(g) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(h) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c)

(i) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(j) Concept: StatisticalClassificationCode

OS - Sales made to other utilities under the guidelines of the appropriate FERC tariff/schedule shown in column (c).

(k) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule No. 60

(l) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule Winnsboro PSA

(m) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(n) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(o) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(p) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(q) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(r) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(s) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2
(t) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2
(u) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2
(v) Concept: RateScheduleTariffNumber
FERC Electric Tariff, Seventh Revised Volume No. 2
(w) Concept: EnergyChargesRevenueNonRequirementsSales
Subtotal non-RQ of $29,862,980 includes transmission revenue for OS service of $1,944,855. Transmission base revenue totals $1,827,099 and ancillary services revenue totals $117,756.
(x) Concept: SalesForResale
This amount does not include $4,757 in revenue from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023. This revenue is reflective of 2,541 MWH.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c) (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	10,165,924	8,779,692
5	(501) Fuel	265,533,645	166,493,550
6	(502) Steam Expenses	4,657,837	4,624,118
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,464,637	1,252,250
10	(506) Miscellaneous Steam Power Expenses	6,078,020	6,795,943
11	(507) Rents		
12	(509) Allowances	37	37
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	287,900,100	187,945,590
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	900,791	868,838
16	(511) Maintenance of Structures	669,714	953,194
17	(512) Maintenance of Boiler Plant	9,315,278	6,829,541
18	(513) Maintenance of Electric Plant	14,360,713	12,105,699
19	(514) Maintenance of Miscellaneous Steam Plant	4,590,590	2,624,864
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,837,086	23,382,136
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	317,737,186	211,327,726
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	13,049,636	13,835,404
25	(518) Fuel	38,568,241	33,591,683
26	(519) Coolants and Water	1,480,599	2,502,573
27	(520) Steam Expenses	6,184,789	8,416,521

28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	651,540	1,291,651
31	(524) Miscellaneous Nuclear Power Expenses	39,945,842	35,998,288
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	99,880,647	95,636,120
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,605,159	8,834,923
36	(529) Maintenance of Structures	1,961,799	2,123,481
37	(530) Maintenance of Reactor Plant Equipment	16,507,739	3,593,234
38	(531) Maintenance of Electric Plant	1,873,161	8,711,401
39	(532) Maintenance of Miscellaneous Nuclear Plant	13,214,010	10,698,872
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	37,161,868	33,961,911
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	137,042,515	129,598,031
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,965,574	1,335,214
45	(536) Water for Power	0	
46	(537) Hydraulic Expenses	840,362	910,997
47	(538) Electric Expenses	1,517,486	1,436,072
48	(539) Miscellaneous Hydraulic Power Generation Expenses	345,457	298,815
49	(540) Rents	10,998	82
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	4,679,877	3,981,180
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	283,484	369,470
54	(542) Maintenance of Structures	490,486	277,528
55	(543) Maintenance of Reservoirs, Dams, and Waterways	711,564	753,494
56	(544) Maintenance of Electric Plant	2,610,705	1,322,624
57	(545) Maintenance of Miscellaneous Hydraulic Plant	969,486	373,491
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,065,725	3,096,607
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	9,745,602	7,077,787
60	D. Other Power Generation		
61	Operation		

62	(546) Operation Supervision and Engineering	2,187,595	2,458,983
63	(547) Fuel	617,450,624	352,000,180
64	(548) Generation Expenses	8,612,218	6,790,247
64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	914,364	1,654,217
66	(550) Rents		732
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	629,164,801	362,904,359
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,820,214	1,585,282
70	(552) Maintenance of Structures	320,654	1,071,858
71	(553) Maintenance of Generating and Electric Plant	14,603,870	14,602,030
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,161,235	1,519,926
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	17,905,973	18,779,096
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	647,070,774	381,683,455
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	287,413,062	275,458,301
76.1	(555.1) Power Purchased for Storage Operations		
77	(556) System Control and Load Dispatching	2,089,029	2,588,776
78	(557) Other Expenses	401,332	
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	289,903,423	278,047,077
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	1,401,499,500	1,007,734,076
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,598,062	1,595,554
85	(561.1) Load Dispatch-Reliability	1,366,173	1,374,934
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,073,184	881,378
87	(561.3) Load Dispatch-Transmission Service and Scheduling	253,041	241,329
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		9,081
90	(561.6) Transmission Service Studies	7,739	
91	(561.7) Generation Interconnection Studies	(82,650)	(46,301)
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,375,353	2,152,679

93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	427,648	538,202
95	(564) Underground Lines Expenses	(114,709)	141,565
96	(565) Transmission of Electricity by Others	[(a)]179,440	[(c)]294,093
97	(566) Miscellaneous Transmission Expenses	7,048,009	5,376,262
98	(567) Rents	40,818	307,733
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	14,172,108	12,866,509
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	204	6,329
102	(569) Maintenance of Structures	17,426	2,944
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment	29,485	41,464
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,329,163	2,224,380
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	6,914,377	8,502,876
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	83,414	88,362
111	TOTAL Maintenance (Total of Lines 101 thru 110)	9,374,069	10,866,355
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	23,546,177	23,732,864
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		

126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of Lines 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,646,658	1,530,886
135	(581) Load Dispatching	1,835,263	1,795,012
136	(582) Station Expenses	2,073,611	1,600,223
137	(583) Overhead Line Expenses	1,797,075	1,814,220
138	(584) Underground Line Expenses	458,069	362,553
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	2,898	71,763
140	(586) Meter Expenses	1,380,598	1,319,870
141	(587) Customer Installations Expenses	208	490
142	(588) Miscellaneous Expenses	4,893,300	4,377,879
143	(589) Rents	2,734,517	2,075,169
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	16,822,197	14,948,065
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	160,241	234,641
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,483,042	1,177,003
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	41,890,878	36,471,424
150	(594) Maintenance of Underground Lines	2,236,544	1,972,338
151	(595) Maintenance of Line Transformers	170,801	84,203
152	(596) Maintenance of Street Lighting and Signal Systems	3,632,658	3,424,099
153	(597) Maintenance of Meters	964,783	547,597
154	(598) Maintenance of Miscellaneous Distribution Plant	2,240,307	1,661,549
155	TOTAL Maintenance (Total of Lines 146 thru 154)	52,779,254	45,572,854
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	69,601,451	60,520,919
157	5. CUSTOMER ACCOUNTS EXPENSES		

158	Operation		
159	(901) Supervision	477,726	466,269
160	(902) Meter Reading Expenses	1,173,703	1,353,915
161	(903) Customer Records and Collection Expenses	18,440,069	18,955,632
162	(904) Uncollectible Accounts	5,805,902	3,866,487
163	(905) Miscellaneous Customer Accounts Expenses	3,213,526	4,112,222
164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	29,110,926	28,754,525
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	1,480	1,937
168	(908) Customer Assistance Expenses	38,553,372	28,550,306
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	38,554,852	28,552,243
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,371,444	1,495,726
176	(913) Advertising Expenses	1,653	1,653
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	1,373,097	1,497,379
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	76,054,878	80,725,255
182	(921) Office Supplies and Expenses	23,883,000	24,734,166
183	(Less) (922) Administrative Expenses Transferred-Credit	29,007,854	(d)24,185,915
184	(923) Outside Services Employed	12,598,531	17,802,775
185	(924) Property Insurance	3,866,784	4,852,394
186	(925) Injuries and Damages	7,287,750	6,850,449
187	(926) Employee Pensions and Benefits	29,298,913	38,983,848
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,858,128	8,159,636
190	(929) (Less) Duplicate Charges-Cr.	9,308,458	9,828,819
191	(930.1) General Advertising Expenses	607,275	902,775

192	(930.2) Miscellaneous General Expenses	4,659,230	10,467,670
193	(931) Rents	9,431,647	11,233,646
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	138,229,824	170,697,880
195	Maintenance		
196	(935) Maintenance of General Plant	17,643,160	18,218,926
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	[b]155,872,984	[c]188,916,806
198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	1,719,558,987	1,339,708,812

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionOfElectricityByOthers

For the formula rate approved in the FERC proceeding listed on page 106, transmission of electricity by others expenses will remove a credit of ($24,464) related to the correction of a duplicate expense from 2021.

For the formula rate approved in the FERC proceeding listed on page 106, transmission of electricity by others will include $61 not included on this page. This is expense from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023. This expense is reflective of 83 MWH.

(b) Concept: AdministrativeAndGeneralExpenses

For the formula rate approved in the FERC proceeding listed on page 106, administrative and general expenses allocable to transmission will exclude $61,485 for Advanced Metering Infrastructure program severance payments not related to transmission.

(c) Concept: TransmissionOfElectricityByOthers

For the formula rate approved in the FERC proceeding listed on page 106, transmission of electricity by others expenses will exclude $24,464 of expenses inadvertently recorded twice.

(d) Concept: AdministrativeExpensesTransferredCredit

In January 2021 as part of the integration with Dominion Energy, Inc., the Company transitioned from its PeopleSoft enterprise software suite to the SAP enterprise software suite used by Dominion Energy. In addition, services being provided to the Company by Dominion Energy Southeast Services, Inc. transitioned to Dominion Energy Services, Inc. (DES). As part of these changes, the Company began using account 922 for the transfer of capitalized administrative expenses billed from DES.

(e) Concept: AdministrativeAndGeneralExpenses

For the formula rate approved in the FERC proceeding listed on page 106, administrative and general expenses allocable to transmission will exclude $778,519 for Advance Metering Infrastructure program severance payments not related to transmission operations.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

PURCHASED POWER (Account 555)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

   RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

   LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

   IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

   SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

   LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

   IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

   OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

   AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the megawatthours shown on bills rendered to the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (k), energy charges in column (l), and the total of any other types of charges, including out-of-period adjustments, in column (m). Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (n) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in columns (g) through (n) must be totaled on the last line of the schedule. The total amount in columns (g) and (h) must be reported as Purchases on Page 401, line 10. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (j) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	Ferc Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		MegaWatt Hours Purchased (Excluding for Energy Storage) (g)	MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER			
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+l+m) of Settlement ($) (n)
1	Newberry Electric Cooperative	RQ	(bm) 0				44					8,735		8,735
2	Santee Cooper (Kempson Bridge)	RQ	(bn) 0				1,234					119,640		119,640
3	Westrock	(b) OS	(bo) 0				36,138					1,106,999		1,106,999
4	Shaw Industries Inc	(c) OS	(bp) 0				1,925					60,053		60,053
5	International Paper	(d) OS	(bq) 0				2,197					105,344		105,344
6	Misc Territorial Customers	(e) OS	(br) Rate--PR1				833					27,203		27,203
7	Southeastern Power Administration	RQ	(bs) 1/2001,12/2002				51						(fm) 75,390	75,390

8	[a] South Carolina Generating Company, Inc	RQ	[bt] Schedule #1		475	371	1,741,918					152,994,307		152,994,307
9	Duke Energy Carolinas, LLC	[f] OS	[bu] Tariff #5				1,382					210,074		210,074
10	Exelon Generation Company, LLC	[g] OS	[bv] Tariff #3				28,030					1,987,715		1,987,715
11	Macquarie Energy LLC	[h] OS	[bw] 0				334,725					46,579,511		46,579,511
12	North Carolina Municipal Power Agency No. 1	[i] OS	[bx] 0				1,138					62,178		62,178
13	PJM Settlement, Inc.	[j] OS	[by] Tariff #1				400					165,312		165,312
14	Southern Company Services, Inc.	[k] OS	[bz] Tariff #4				20,846					1,394,714		1,394,714
15	The Energy Authority, Inc	[l] OS	[ca] 12/1/2004				3,612					431,367		431,367
16	Duke Energy Carolinas, LLC -- Emergency	[m] OS	[cb] 0				3,120					5,039,293		5,039,293
17	Carolina Power Partners, LLC	[n] OS	[cc] 0				5,321					408,772		408,772
18	Barnwell Solar, LLC	[o] OS	[cd] 0				11,140					579,264		579,264
19	Cameron Solar II, LLC	[p] OS	[ce] 0				8,858					460,596		460,596
20	Haley Solar I, LLC	[q] OS	[cf] 0				16,688					867,787		867,787
21	Odyssey Solar, LLC	[r] OS	[cg] 0				18,285					950,801		950,801
22	Ridgeland Solar Farm I, LLC	[s] OS	[ch] 0				18,085					994,671		994,671
23	Saluda Solar II, LLC	[t] OS	[ci] 0				6,852					356,317		356,317
24	Saluda Solar, LLC	[u] OS	[cj] 0				13,959					725,858		725,858
25	TIG Sun Energy III, LLC	[v] OS	[ck] 0				894					87,961		87,961
26	TIG Sun Energy IV, LLC	[w] OS	[cl] 0				2,877					279,330		279,330
27	Cameron Solar, LLC	[x] OS	[cm] 0				44,918					2,200,978		2,200,978
28	Champion Solar, LLC	[y] OS	[cn] 0				23,959					1,173,972		1,173,972
29	Estill Solar I, LLC	[z] OS	[co] 0				38,900					1,906,092		1,906,092
30	Estill Solar II, LLC	[aa] OS	[cp] 0				19,216					941,594		941,594
31	Hampton Solar I, LLC	[ab] OS	[cq] 0				13,961					684,068		684,068
32	Hampton Solar II, LLC	[ac] OS	[cr] 0				41,855					2,050,900		2,050,900
33	Southern Current One, LLC	[ad] OS	[cs] 0				18,614					912,070		912,070
34	St. Matthews Solar, LLC	[ae] OS	[ct] 0				19,498					955,391		955,391
35	Swamp Fox Solar, LLC	[af] OS	[cu] 0				23,594					1,156,091		1,156,091

36	Moffett Solar 1, LLC	[ag] OS	[cv] 0	[dz] 0			137,701			[et] 0	1,690,839	4,371,330		6,062,169
37	Seabrook Solar, LLC	[ah] OS	[cw] 0	[ea] 0			134,572			[eu] 0	699,939	3,554,566		4,254,505
38	Billing Credit Agreement (BCA) DER Solar Power Purchases	[ai] OS	[cx] 0				21,121					4,447,438		4,447,438
39	Blackville Solar II, LLC	[aj] OS	[cy] 0	[eb] 0			34,014			[ev] 0	148,076	869,201		1,017,277
40	Diamond Solar, LLC	[ak] OS	[cz] 0	[ec] 0			11,603			[ew] 0	53,210	294,062		347,272
41	Edison Solar, LLC	[al] OS	[da] 0	[ed] 0			7,896			[ex] 0	37,985	203,046		241,031
42	Palmetto Plains Solar Project, LLC	[am] OS	[db] 0	[ee] 0			157,325			[ey] 0	802,311	4,580,555		5,382,866
43	Peony Solar LLC	[an] OS	[dc] 0	[ef] 0			78,345			[ez] 0	394,282	2,074,554		2,468,836
44	Gaston Solar I, LLC	[ao] OS	[dd] 0				19,552					958,054		958,054
45	Gaston Solar II, LLC	[ap] OS	[de] 0				12,222					544,551		544,551
46	Richardson Solar, LLC	[aq] OS	[df] 0	[eg] 0			7,462			[fa] 0	36,662	196,158		232,820
47	Shaw Creek Solar, LLC	[ar] OS	[dg] 0	[eh] 0			173,092			[fb] 0	794,851	5,206,222		6,001,073
48	Nimitz Solar, LLC	[as] OS	[dh] 0				16,010					1,417,979		1,417,979
49	Springfield Solar, LLC	[at] OS	[di] 0				11,470					1,026,345		1,026,345
50	Curie Solar, LLC	[au] OS	[dj] 0				3,229					290,650		290,650
51	Parris Island	[av] OS	[dk] 0				855					27,940		27,940
52	Huntley Solar, LLC	[aw] OS	[dl] 0	[ei] 0			164,256			[fc] 0	839,127	4,859,463		5,698,590
53	Lily Solar, LLC	[ax] OS	[dm] 0	[ej] 0			163,778			[fd] 0	786,687	4,392,830		5,179,517
54	Midlands Solar, LLC	[ay] OS	[dn] 0	[ek] 0			143,699			[fe] 0	201,338	3,953,913		4,155,251
55	TWE Bowman Solar Project, LLC	[az] OS	[do] 0	[el] 0			145,567			[ff] 0	224,986	4,268,910		4,493,896
56	Blackville Solar, LLC	[ba] OS	[dp] 0	[em] 0			16,013			[fg] 0	21,989	452,884		474,873
57	Denmark Solar, LLC	[bb] OS	[dq] 0	[en] 0			12,707			[fh] 0	20,919	361,729		382,648
58	Yemassee Solar, LLC	[bc] OS	[dr] 0	[eo] 0			22,373			[fi] 0	33,473	635,126		668,599
59	Trask East Solar, LLC	[bd] OS	0	[ep] 0			26,195			[fj] 0	39,997	743,106		783,103
60	Beulah Solar, LLC	[be] OS	[ds] 0	[eq] 0			115,683			[fk] 0	232,441	3,397,094		3,629,535
61	Georgia Power (Calhoun Falls)	[bf] OS	Schedule #793	0			1			0		523		523
62	Oglethorpe Power Corporation	[bg] OS	[dt] 0	0			12			0		3,186		3,186
63	LG&E and KU Energy, LLC	[bh] OS	[du] 0	0			865			0		59,996		59,996

64	Duke Energy Florida, LLC	[(bi)] OS	[(dv)] 0	0			1,070			0		69,750		69,750
65	Duke Energy Progress, LLC -- Emergency	[(bj)] OS	[(dw)] 0	0			2,925			0		5,851,463		5,851,463
66	Southern Company Services, Inc. -- Emergency	[(bk)] OS	[(dx)] 0	0			3,500			0		7,000,000		7,000,000
67	Other	[(bl)] OS	[(dy)] 0	[(er)] 0						[(fl)] 0				
68	Adjustments						[(es)] 67,581						(13,819,022) [(fn)]	(13,819,022)
15	TOTAL						4,237,761	0	0	0	7,059,112	294,097,582	(13,743,632)	287,413,062

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower

Affiliated Company

(b) Concept: StatisticalClassificationCode

OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.

(c) Concept: StatisticalClassificationCode

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(bl) Concept: StatisticalClassificationCode
OS - Purchases made from other suppliers under the guidelines of the appropriate FERC tariff / schedule.
(bm) Concept: RateScheduleTariffNumber
Contracts for electric service dated 11/1/1975 and 5/15/1976.
(bn) Concept: RateScheduleTariffNumber
Contract for electric service dated 1/1/1996.
(bo) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2019-16-E, Order No. 2019-36.
(bp) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2019-344-E, Order No. 2019-806.
(bq) Concept: RateScheduleTariffNumber
Contract for electric service dated 5/1/1984.
(br) Concept: RateScheduleTariffNumber
Various agreements for purchased power from customers pursuant to the Company's PR-1 (Small Power Production, Cogeneration) Rate Schedule.
(bs) Concept: RateScheduleTariffNumber
Docket Nos. ER01-1043-000 and ER03-237-000.
(bt) Concept: RateScheduleTariffNumber
FERC Electric Rate Schedule No. 1, Schedule 8 Billing Format - Cost of Service Tariff Docket Nos. ER85-204-007 and ER85-603-005.
(bu) Concept: RateScheduleTariffNumber
Tariff No. 5, Docket No. ER12-2322.
(bv) Concept: RateScheduleTariffNumber
FERC Electric Tariff Volume No. 3, Docket No. ER14-1625.
(bw) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 9/1/2002.
(bx) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 6/1/2003.
(by) Concept: RateScheduleTariffNumber
Tariff No. 1, Docket No. ER10-2778
(bz) Concept: RateScheduleTariffNumber
Tariff No. 4, Docket No. ER10-2881.
(ca) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2004.
(cb) Concept: RateScheduleTariffNumber
FERC Electric Rate Schedule No. 42.
(cc) Concept: RateScheduleTariffNumber
Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 8/20/2021.

(cd) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-175-E, Order Nos. 2016-368, 2017-311 and 2017-546.
(ce) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-177-E, Order Nos. 2016-369, 2017-312 and 2017-547.
(cf) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-178-E, Order Nos. 2016-370 and 2017-315.
(cg) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-181-E, Order Nos. 2016-372, 2017-316 and 2017-549.
(ch) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-278-E, Order No. 2016-548.
(ci) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-174-E, Order Nos. 2016-367, 2017-317 and 2017-552.
(cj) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-182-E, Order Nos. 2016-373 and 2017-326.
(ck) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-363-E, Order No. 2015-788.
(cl) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-166-E, Order No. 2017-373.
(cm) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-167-E, Order No. 2016-341, 2017-309, and 2017-310.
(cn) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-171-E, Order No. 2016-364 and 2017-313.
(co) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-173-E, Order No. 2016-366, 2017-285, and 2017-286.
(cp) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-378-E, Order No. 2015-812 and 2017-289.
(cq) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-380-E, Order No. 2015-814, 2016-324, 2017-293, and 2017-548.
(cr) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-169-E, Order No. 2016-343, 2017-287, and 2017-288.
(cs) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-379-E, Order No. 2015-813, 2017-318, and 2017-551.
(ct) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-168-E, Order No. 2016-342, 2017-319, and 2017-550.
(cu) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-179-E, Order No. 2016-371 and 2017-320.
(cv) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-100-E, Order No. 2016-200.
(cw) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order no. 2017-424.
(cx) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2015-54-E, Order Nos. 2015-512 and 2015-765.

(cy) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-181-E, Order No. 2017-417.
(cz) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-182-E, Order No. 2017-418.
(da) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-183-E, Order No. 2017-419.
(db) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-160-E, Order No. 2017-372.
(dc) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dd) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-172-E, Order Nos. 2016-365 and 2017-290.
(de) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-170-E, Order Nos. 2016-344 and 2017-314.
(df) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-186-E, Order No. 2017-422.
(dg) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-143-E, Order No. 2017-321.
(dh) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-290-E; 2015-54-E, Order Nos. 2016-707, 2017-151, 2018-57, 2018-583, 2015-512 and 2016-846.
(di) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-290-E; 2015-54-E, Order Nos. 2016-707, 2017-151, 2018-57, 2018-583, 2015-512 and 2016-846.
(dj) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2016-290-E; 2015-54-E, Order Nos. 2016-707, 2017-151, 2018-57, 2018-583, 2015-512 and 2016-846.
(dk) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2019-344-E, Order No. 2019-806.
(dl) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dm) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dn) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(do) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-187-E, Order No. 2017-423.
(dp) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424.
(dq) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424.
(dr) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-188-E, Order No. 2017-424.
(ds) Concept: RateScheduleTariffNumber
SCPSC Docket No. 2017-160-E, Order No. 2017-372.

(dt) Concept: RateScheduleTariffNumber

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 9/1/2004.

(du) Concept: RateScheduleTariffNumber

Edison Electric Institute Inc. (EEI) Master Power Purchase and Sale Agreement effective 12/1/2003.

(dv) Concept: RateScheduleTariffNumber

FERC Electric Tariff, Seventh Revised Volume No. 2

(dw) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule No. 29.

(dx) Concept: RateScheduleTariffNumber

FERC Electric Rate Schedule No. 30.

(dy) Concept: RateScheduleTariffNumber

SCPSC Docket No. 2017-188-E, Order No. 2017-424

(dz) Concept: AverageMonthlyBillingDemand

Moffet Solar 1, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of June, July and August as specified in the contract.

(ea) Concept: AverageMonthlyBillingDemand

Seabrook Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(eb) Concept: AverageMonthlyBillingDemand

Blackville Solar II, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ec) Concept: AverageMonthlyBillingDemand

Diamond Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ed) Concept: AverageMonthlyBillingDemand

Edison Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ee) Concept: AverageMonthlyBillingDemand

Palmetto Plains Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ef) Concept: AverageMonthlyBillingDemand

Peony Solar LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(eg) Concept: AverageMonthlyBillingDemand

Richardson Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(eh) Concept: AverageMonthlyBillingDemand

Shaw Creek Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ei) Concept: AverageMonthlyBillingDemand

Huntley Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ej) Concept: AverageMonthlyBillingDemand

Lily Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(ek) Concept: AverageMonthlyBillingDemand

Midlands Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(el) Concept: AverageMonthlyBillingDemand

TWE Bowman Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(em) Concept: AverageMonthlyBillingDemand

Blackville Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(en) Concept: AverageMonthlyBillingDemand

Denmark Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(eo) Concept: AverageMonthlyBillingDemand
Yamassee Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ep) Concept: AverageMonthlyBillingDemand
Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(eq) Concept: AverageMonthlyBillingDemand
Beulah Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(er) Concept: AverageMonthlyBillingDemand
Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(es) Concept: MegawattHoursPurchasedOtherThanStorage
Includes 67,581 megawatt hours of Net Energy Metering purchases from customers which are not classified as purchased power but have been shown on this schedule in order for total megawatt hours purchased reported on this schedule to tie to page 401a, line 10 column b in accordance with the Taxonomy provided by FERC.
(et) Concept: EnergyDeliveredThroughPowerExchanges
Moffet Solar 1, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of June, July and August as specified in the contract.
(eu) Concept: EnergyDeliveredThroughPowerExchanges
Seabrook Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ev) Concept: EnergyDeliveredThroughPowerExchanges
Blackville Solar II, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ew) Concept: EnergyDeliveredThroughPowerExchanges
Diamond Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ex) Concept: EnergyDeliveredThroughPowerExchanges
Edison Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ey) Concept: EnergyDeliveredThroughPowerExchanges
Palmetto Plains Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ez) Concept: EnergyDeliveredThroughPowerExchanges
Peony Solar LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fa) Concept: EnergyDeliveredThroughPowerExchanges
Richardson Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fb) Concept: EnergyDeliveredThroughPowerExchanges
Shaw Creek Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fc) Concept: EnergyDeliveredThroughPowerExchanges
Huntley Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fd) Concept: EnergyDeliveredThroughPowerExchanges
Lily Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fe) Concept: EnergyDeliveredThroughPowerExchanges
Midlands Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(ff) Concept: EnergyDeliveredThroughPowerExchanges
TWE Bowman Solar Project, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fg) Concept: EnergyDeliveredThroughPowerExchanges
Blackville Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fh) Concept: EnergyDeliveredThroughPowerExchanges
Denmark Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fi) Concept: EnergyDeliveredThroughPowerExchanges
Yamassee Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.

(fj) Concept: EnergyDeliveredThroughPowerExchanges
Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fk) Concept: EnergyDeliveredThroughPowerExchanges
Beulah Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fl) Concept: EnergyDeliveredThroughPowerExchanges
Trask East Solar, LLC has the opportunity to earn a demand payment (expressed in $/kWh) when power is delivered during critical peak hours during the months of January, February, June, July, August and December as specified in the contract.
(fm) Concept: OtherChargesOfPurchasedPower
Energy Charges represent a barter arrangement for transmission ancillary services 1,2,5 and 6.
(fn) Concept: OtherChargesOfPurchasedPower
Reflects amortization of previously deferred purchased power of $126,595 per SCPSC Docket No. 2009-489-E, 2012-218-E, 2017-210-E and 2020-125-E. Reflects amortization of previously deferred purchased power of $282,659 per SCPSC Docket No. 2009-489-E. Reflects the deferral of capacity purchases per SCPSC Docket No. 2020-125-E of $711,504. Reflects Fuel Adjustment per 2021 ORS Fuel Audit Attachment H (1,205). Reflects Boeing Green Premium 18,631.41. Reflects the deferral of purchase power of ($12,484,995) pursuant to SCPSC Docket No. 2015-54-E, under the Company's Distributed Energy Resources (DER) program. Reflects the Solar Project Penalties of ($1,078,570). Reflects Boeing Green Premium ($41,277) Reflects amortization of EDIT from GENCO per SCPSC Docket No. 2020-125-E of (1,352,364).

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referred to as "wheeling")

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c).
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.
9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (0) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)	Ferc Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY Megawatt Hours Received (i)	Megawatt Hours Delivered (j)	REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total Revenues ($) (k+l+m) (n)
1	Southern Company Services, Inc.	Duke Energy Carolinas, LLC	Georgia Power Company	NF	S8,S1,S2	DUK	SOCO	[(h)]0	[(k)]20,288	[(x)]19,799	122,303		[(an)]8,188	130,491
2	The Energy Authority	Georgia Power Company	South Carolina Public Service Authority	SFP	S7,S1,S2	SOCO	SC	2,322	[(l)]49,891	[(y)]48,900	243,228		[(ao)]16,242	259,470
3	Macquarie Energy LLC	Georgia Power Company	South Carolina Public Service Authority	SFP	S7,S1,S2	SOCO	SC	116	[(m)]2,699	[(z)]2,645	13,019		[(ap)]798	13,817
4	Macquarie Energy LLC	Georgia Power Company	Duke Energy Carolinas, LLC	SFP	S7,S1,S2	SOCO	DUK	568	[(n)]8,425	[(aa)]8,257	64,106		[(aq)]4,039	68,145
5	Macquarie Energy LLC	Duke Energy Carolinas, LLC	Georgia Power Company	NF	S8,S1,S2	DUK	SOCO	[(i)]0	[(o)]699	[(ab)]685	4,963		[(ar)]319	5,282
6	Macquarie Energy LLC	Progress Energy Carolinas, LLC	Georgia Power Company	NF	S8,S1,S2	CPLE	SOCO	[(j)]0	[(p)]140	[(ac)]137	993		[(as)]64	1,057
7	Carolina Power Partners, LLC	Georgia Power Company	Duke Energy Carolinas, LLC	SFP	S7,S1,S2	SOCO	CPLE	45	[(q)]1,078	[(ad)]1,056	5,102		[(at)]328	5,430
8	South Carolina Public Service Authority	South Carolina Public Service Authority	Central Electric Power Co-op	FNO	[(b)]Attach H			759	[(r)]341,063	[(ae)]331,128	3,603,918	[(ak)]44,712	[(au)]113,251	[(ba)]3,761,881
9	Southeastern Power Administration	Southeastern Power Administration	[(a)]See footnote	FNO	[(c)]Attach H			240	[(s)]38,131	[(af)]36,895	1,163,627		[(av)]75,390	[(bb)]1,239,017
10	City of Orangeburg	Dominion Energy South Carolina, Inc.	City of Orangeburg	FNO	[(d)]Attach H			1,463	[(t)]789,512	[(ag)]766,516	7,092,560		[(aw)]527,245	[(bc)]7,619,805
11	Town of Winnsboro	Dominion Energy South Carolina, Inc.	Town of Winnsboro	FNO	[(e)]Attach H			113	[(u)]59,734	[(ah)]58,562	546,387		[(ax)]40,618	[(bd)]587,005
12	Central Electric Power Co-op	South Carolina Public Service Authority	Central Electric Power Co-op	FNO	[(f)]Attach H			168	[(v)]65,530	[(ai)]64,245	794,707	[(al)]11,671	[(ay)]24,945	[(be)]831,323
13	McCormick Commission of Public Works	Duke Energy Carolinas, LLC	McCormick Commission of Public Works	FNO	[(g)]Attach H			39	[(w)]19,539	[(aj)]19,157	186,747	[(am)](36,860)	[(az)]13,896	[(bf)]163,783
35	TOTAL							5,833	1,396,729	1,357,982	13,841,660	19,523	825,323	[(bg)]14,686,506

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

South Carolina Public Service Authority, Little River Electric Cooperative, McCormick CPW, City of Orangeburg and Town of Winnsboro.

(b) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1 S2 and S4 of Tariff.

(c) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S5 and S6 of Tariff.

(d) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

(e) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S3, S5 and S6 of Tariff.

(f) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2 and S4 of Tariff.

(g) Concept: RateScheduleTariffNumber

Also includes Rate Schedules S1, S2, S3, S4, S5 and S6 of Tariff.

(h) Concept: BillingDemand

Non-firm hourly billing demand of 20,619.

(i) Concept: BillingDemand

Non-firm hourly billing demand of 700.

(j) Concept: BillingDemand

Non-firm hourly billing demand of 140.

(k) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(l) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(m) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(n) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(o) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(p) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(q) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(r) Concept: TransmissionOfElectricityForOthersEnergyReceived

Actual energy flows in MWH are listed rather than transmission reservation quantities.

(s) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(t) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(u) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(v) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(w) Concept: TransmissionOfElectricityForOthersEnergyReceived
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(x) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(y) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(z) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(aa) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ab) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ac) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ad) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ae) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(af) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ag) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ah) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ai) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(aj) Concept: TransmissionOfElectricityForOthersEnergyDelivered
Actual energy flows in MWH are listed rather than transmission reservation quantities.
(ak) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.
(al) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.
(am) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers
Charges for Ancillary Service 4 (Energy Imbalance). The reported amount does not include energy imbalance penalties which are allocated to non-offending transmission customers.

(an) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(ao) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(ap) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges
(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(at) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(au) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1 and 2 charges.
(av) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1, 2, 5 and 6 charges.
(aw) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Services 1, 2, 3, 5 and 6 charges.
(ax) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Service 1, 2, 3, 5 and 6 charges.
(ay) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Services 1 and 2 charges.
(az) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
Sum of Ancillary Services 1, 2, 3, 5 and 6 charges.
(ba) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(bb) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(bc) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(bd) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(be) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(bf) Concept: RevenuesFromTransmissionOfElectricityForOthers
Network transmission revenue.
(bg) Concept: RevenuesFromTransmissionOfElectricityForOthers
This amount does not include $732 in revenue from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023. This revenue is reflective of 763 MWH .

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
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36					
37					
38					
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42					
43					
44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows:
   FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter ""TOTAL"" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			MegaWatt Hours Received (c)	MegaWatt Hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Duke Energy Carolinas	FNS	5,447	5,872	8,750	56,296	[a]7,390	72,436
2	Duke Energy Carolinas	NF	97	97	239		[b]38	277
3	Duke Energy Progress	NF	400	400	5,320		[c]340	5,660
4	PJM Settlement, Inc.	NF					[d]1,956	1,956
5	Central Electric Power Cooperative, Inc.	OS					[e]112,592	112,592
6	Santee Cooper	SFP	1,975	1,917	10,885		[f]1,677	12,562
7	Adjustments						[g](26,043)	(26,043)
	TOTAL		7,919	8,286	25,194	56,296	97,950	[h]179,440

FOOTNOTE DATA

(a) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	40
Reactive Supply and Voltage Control		958
Regulation and Frequency Response		182
Operating Reserve - Spinning		390
Operating Reserve - Supplement		390
Other - Direct Assignment Charges		5,430
Total	$	7,390

(b) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	11
Reactive Supply and Voltage Control		27
Total	$	38

(c) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	100
Reactive Supply and Voltage Control	$	240
Total	$	340

(d) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	—
Reactive Supply and Voltage Control		1
Operating Reserve -- Spinning		(5)
Real-Time Load Response Charge Allocation		1
Other - PJM Settlement, Inc.		619
Estimated Transmission for December 2022 - To be reversed and actualized in January 2023		1,340
Total	$	1,956

(e) Concept: OtherChargesTransmissionOfElectricityByOthers

Other - Sewee/Commonwealth Transmission Facility Charges	$	112,592
Total	$	112,592

(f) Concept: OtherChargesTransmissionOfElectricityByOthers

Scheduling, System Control and Dispatch	$	464
Reactive Supply and Voltage Control		1,213
Total	$	1,677

(g) Concept: OtherChargesTransmissionOfElectricityByOthers

Duke Energy Carolinas, LLC loss related to January 2022 Purchase Wheeling transaction	$	140
Excess Amount accrued in Q4 2021 related to Duke Energy Progress. Adjusted in January 2022.		(1,719)
Excess Amount accrued in Q4 2021 related to PJM. Adjusted in January 2022.		(24,464)
Total	$	(26,043)

(h) Concept: ChargesForTransmissionOfElectricityByOthers

83 mwh totaling $61 of Transmission provided by others is not included in the totals on this page. This is expense from a new energy trading platform that occurred in Q4 2022, but was not booked until Q1 2023.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	247,469
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,000,188
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Transportation and Other Power Operating equipment	
7	Environmental Fees	33,924
8	Financing Fees	152,757
9	DES Billing - Amortization	842,516
10	DES Billing - Depreciation	189,579
11	DES Billing - Property Taxes	223,802
12	Research & Development Grant Amortization	100,000
13	Misc Expense	1,868,995
46	TOTAL	4,659,230

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Depreciation and Amortization of Electric Plant (Account 403, 404, 405)

1. Report in section A for the year the amounts for: (b) Depreciation Expense (Account 403); (c) Depreciation Expense for Asset Retirement Costs (Account 403.1); (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
   Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
   In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
   For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type of mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,916,125		2,916,125
2	Steam Production Plant	63,920,021				63,920,021
3	Nuclear Production Plant	26,502,189				26,502,189
4	Hydraulic Production Plant-Conventional	2,788,756				2,788,756
5	Hydraulic Production Plant-Pumped Storage	2,683,900				2,683,900
6	Other Production Plant	22,761,417				22,761,417
7	Transmission Plant	49,332,352				49,332,352
8	Distribution Plant	94,512,741				94,512,741
9	Regional Transmission and Market Operation					
10	General Plant	4,145,086				4,145,086
11	Common Plant-Electric	6,467,352		3,565,238		10,032,590
12	TOTAL	273,113,814		6,481,363		279,595,177

B. Basis for Amortization Charges

Electric Intangible Plant (Account 404) consists of Amortization of Parr Hydro Project #516, Stevens Creek Project #2535, Neal Shoals Project #2315 and relicensing costs associated with VC Summer Nuclear Station. The charges were based on plant balances of Parr -$7,272,676, Stevens Creek- $2,268,402, Neal Shoals-$1,507,162. The associated costs of relicensing the VC Summer Nuclear Plant through 2062 is $8,564,832. Data processing software costs of $81,225,963 are being amortized over the expected life of the software application. Common Plant (Account 404) represents the amortization of data processing software of $146,397,143 over the expected life of the software application.

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (in Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	[(a)] See Footnote						
13	Steam Production:						
14	Urquhart - 311	19,251	80 years	(13)%	1.99%	R2	15 years, 9 months, 18 days
15	Urquhart - 312	27,275	41 years	(13)%	5.59%	S0	13 years, 4 months, 24 days
16	Urquhart - 314	62,480	52 years	(13)%	4.03%	S0	15 years, 4 months, 24 days
17	Urquhart - 315	19,429	65 years	(13)%	5.29%	R2	15 years, 10 months, 25 days

18	Urquhart - 316	7,063	41 years	(13)%	4.99%	R0.5	14 years, 10 months, 25 days
19	Total Urquhart	135,498					
20	McMeekin - 311	19,832	80 years	(16)%	2.61%	R2	18 years, 8 months, 12 days
21	McMeekin - 312	111,488	41 years	(16)%	3.77%	S0	16 years, 3 months, 19 days
22	McMeekin - 314	47,102	52 years	(16)%	3.19%	S0	17 years, 7 months, 6 days
23	McMeekin - 315	12,101	65 years	(16)%	2.88%	R2	18 years, 10 months, 25 days
24	McMeekin - 316	7,824	41 years	(16)%	3.99%	R0.5	16 years, 7 months, 6 days
25	Total McMeekin	198,347					
26	Cope - 311	82,949	80 years	(17)%	1.55%	R2	46 years, 1 month, 6 days
27	Cope - 312	329,776	41 years	(17)%	2.34%	S0	28 years, 1 month, 6 days
28	Cope - 312 SCR	71,322	41 years	(17)%	2.34%	S0	28 years, 1 month, 6 days
29	Cope - 314	91,190	52 years	(17)%	1.62%	S0	33 years, 7 months, 6 days
30	Cope - 315	24,363	65 years	(17)%	1.49%	R2	40 years, 10 months, 25 days
31	Cope - 316	12,681	41 years	(17)%	2.59%	R0.5	31 years, 3 months, 19 days
32	Cope - 316 SCR	618	41 years	(17)%	2.59%	R0.5	31 years, 3 months, 19 days
33	Total Cope	612,899					
34	Columbia Energy Center - 311 Initial Investment	[(b)]4,625					
35	Columbia Energy Center - 312 Initial Investment	[(c)]23,475					
36	Columbia Energy Center - 314 Initial Investment	[(d)]68,486					
37	Columbia Energy Center - 316 Initial Investment	[(e)]1,719					
38	Columbia Energy Center - 311	29	80 years	(15)%	0.8%	R2	34 years, 8 months, 12 days
39	Columbia Energy Center - 312	1,687	41 years	(15)%	0.19%	S0	29 years, 10 months, 25 days
40	Columbia Energy Center - 314	2,882	52 years	(15)%	0.5%	S0	31 years, 9 months, 18 days
41	Columbia Energy Center - 315	12	65 years	(15)%	0.88%	R2	34 years, 3 months, 19 days
42	Columbia Energy Center - 316	96	41 years	(15)%	1.58%	R0.5	29 years, 1 month, 6 days
43	Total Columbia Energy Center	103,011					
44	Jasper - 311		80 years	(13)%	4.53%	R2	24 years, 10 months, 25 days
45	Jasper - 312	509	41 years	(13)%	4.68%	S0	22 years, 7 months, 6 days
46	Jasper - 314	100,396	52 years	(13)%	3.87%	S0	22 years, 2 months, 12 days
47	Jasper - 315	7,221	65 years	(13)%	3.63%	R2	24 years, 3 months, 19 days
48	Jasper - 316	524	41 years	(13)%	4.48%	R0.5	21 years, 9 months, 18 days

49	Total Jasper	108,650					
50	Central Lab - 311	3,515	80 years	(9)%	1.59%	R2	18 years, 9 months, 18 days
51	Central Lab - 315	59	65 years	(9)%	0.89%	R2.5	17 years, 9 months, 18 days
52	Central Lab - 316	2,872	41 years	(9)%	4.01%	R0.5	17 years, 1 month, 6 days
53	Total Central Lab	6,446					
54	Wateree - 311	69,238	80 years	(17)%	3.26%	R2	25 years, 6 months
55	Wateree - 311 Scrubber	81,557	80 years	(17)%	3.26%	R2	25 years, 6 months
56	Wateree - 312	401,094	41 years	(17)%	3.59%	S0	21 years, 4 months, 24 days
57	Wateree - 312 Scrubber	224,050	41 years	(17)%	3.59%	S0	21 years, 4 months, 24 days
58	Wateree - 314	141,052	52 years	(17)%	2.87%	S0.5	22 years, 7 months, 6 days
59	Wateree - 315	31,001	65 years	(17)%	3.27%	R2	24 years, 8 months, 12 days
60	Wateree - 316	10,830	41 years	(17)%	4.16%	R0.5	21 years, 7 months, 6 days
61	Total Wateree	958,822					
62	Nuclear Production:						
63	V.C. Summer -321	393,933	80 years	(3)%	1.32%	R2.5	39 years, 3 months, 19 days
64	V.C. Summer -322	561,036	60 years	(5)%	1.71%	R2.5	35 years, 3 months, 19 days
65	V.C. Summer -323	110,011	45 years	(5)%	2.74%	S1	27 years, 1 month, 6 days
66	V.C. Summer -324	118,863	55 years	(1)%	1.31%	R3	29 years, 2 months, 12 days
67	V.C. Summer -325	198,207	30 years	(3)%	3.77%	R2.5	19 years, 2 months, 12 days
68	V.C. Summer -325.5	10,973	30 years		3.5%	R2.5	28 years, 2 months, 12 days
69	Total V.C. Summer	1,393,023					
70	Hydro Production - Conventional:						
71	Neal Shoals - 331	838	110 years	(19)%	1.64%	R2	35 years, 1 month, 6 days
72	Neal Shoals - 332	5,269	125 years	(19)%	2.64%	R2.5	34 years, 7 months, 6 days
73	Neal Shoals - 333	3,954	90 years	(19)%	2.35%	S0.5	33 years, 4 months, 24 days
74	Neal Shoals - 334	511	50 years	(19)%	2.49%	O1	28 years, 10 months, 25 days
75	Neal Shoals - 335	386	65 years	(19)%	2.55%	R1.5	32 years, 9 months, 18 days
76	Neal Shoals - 336	3	75 years	(19)%	1.18%	R4	33 years, 6 months
77	Total Neal Shoals	10,961					
78	Parr - 331	1,887	110 years	(19)%	2.33%	R2	42 years, 9 months, 18 days
79	Parr - 332	5,884	125 years	(19)%	1.92%	R2.5	42 years, 1 month, 6 days
80	Parr - 333	2,834	90 years	(19)%	2.33%	S0.5	40 years, 6 months
81	Parr - 334	2,025	50 years	(19)%	2.25%	O1	33 years, 3 months, 19 days
82	Parr - 335	828	65 years	(19)%	2.21%	R1.5	39 years, 6 months
83	Parr - 336	124	75 years	(19)%	1.21%	R4	43 years, 7 months, 6 days

84	Total Parr	13,582					
85	Stevens Ck - 331	3,175	110 years	(18)%	1.13%	R2	55 years, 6 months
86	Stevens Ck - 332	8,453	125 years	(18)%	0.92%	R2.5	57 years, 10 months, 25 days
87	Stevens Ck - 333	3,213	90 years	(18)%	1.43%	S0.5	51 years, 1 month, 6 days
88	Stevens Ck - 334	928	50 years	(18)%	1.89%	O1	36 years, 6 months
89	Stevens Ck - 335	1,530	65 years	(18)%	1.68%	R1.5	48 years
90	Stevens Ck - 336	129	75 years	(18)%	1.33%	R4	54 years, 6 months
91	Total Stevens Ck	17,428					
92	Saluda - 331	8,143	110 years	(4)%	1.19%	R2	56 years, 4 months, 24 days
93	Saluda - 332	21,738	125 years	(4)%	0.66%	R2.5	52 years, 9 months, 18 days
94	Saluda - 332.5 (Backup Dam)	332,840	125 years	(4)%	0.39%	R2.5	60 years, 7 months, 6 days
95	Saluda - 333	11,705	90 years	(4)%	1.07%	S0	48 years
96	Saluda - 334	9,953	50 years	(4)%	2.43%	O1	39 years, 8 months, 12 days
97	Saluda - 335	3,455	65 years	(4)%	1.74%	R1.5	48 years, 6 months
98	Saluda - 336	234	75 years	(4)%	0.88%	R4	44 years, 7 months, 6 days
99	Total Saluda	388,068					
100	Hydro Production - Pumped Storage:						
101	Fairfield - 331	37,740	110 years	(19)%	0.94%	R2	74 years
102	Fairfield - 332	74,835	125 years	(19)%	0.86%	R2.5	82 years, 6 months
103	Fairfield - 333	68,399	90 years	(19)%	1.33%	S0	64 years, 8 months, 12 days
104	Fairfield - 334	21,811	50 years	(19)%	2.53%	O1	45 years, 10 months, 25 days
105	Fairfield - 335	7,102	65 years	(19)%	2.62%	R1.5	43 years, 7 months, 6 days
106	Fairfield - 336	1,328	75 years	(19)%	1.6%	R4	35 years, 9 months, 18 days
107	Total Fairfield	211,215					
108	Other Production - Gas Turbine Units:						
109	Hardeeville - 341	58	55 years	(10)%	0.75%	R2.5	1 year
110	Hardeeville - 342	534	55 years	(10)%	(9.34)%	R2	1 year
111	Hardeeville - 343	799	35 years	(10)%	(4.65)%	R2	1 year
112	Hardeeville - 344	1,863	65 years	(10)%	(9.61)%	S1	1 year
113	Hardeeville - 345	283	40 years	(10)%	(8.77)%	S2	1 year
114	Hardeeville - 346	74	42 years	(10)%	11.4%	R1	1 year
115	Total Hardeeville	3,611					
116	Coit - 341	147	55 years	(10)%	2.27%	R2.5	10 years, 3 months, 19 days
117	Coit - 342	605	55 years	(10)%	2.1%	R2	10 years, 2 months, 12 days

118	Coit - 343	1,380	35 years	(10)%	3.62%	R2	9 years, 10 months, 25 days
119	Coit - 344	3,490	65 years	(10)%	0.61%	S1	9 years, 6 months
120	Coit - 345	622	40 years	(10)%	3.92%	S2	10 years, 2 months, 12 days
121	Coit - 346	172	42 years	(10)%	2.8%	R1	9 years, 10 months, 25 days
122	Total Coit	6,416					
123	Parr - 341	890	55 years	(10)%	2.05%	R2.5	20 years, 3 months, 19 days
124	Parr - 342	565	55 years	(10)%	1.14%	R2	17 years, 8 months, 12 days
125	Parr - 343	4,519	35 years	(10)%	3.82%	R2	18 years, 9 months, 18 days
126	Parr - 344	3,371	65 years	(10)%	2.29%	S1	18 years, 8 months, 12 days
127	Parr - 345	1,606	40 years	(10)%	2.11%	S2	18 years, 10 months, 25 days
128	Parr - 345.5	1,833	40 years	(10)%	4.78%	S2	21 years
129	Parr - 346	270	42 years	(10)%	2.83%	R1	19 years
130	Total Parr	11,221					
131	Bushy Park - 341	654	55 years	(11)%	11.33%	R2.5	6 years, 4 months, 24 days
132	Bushy Park - 342	400	55 years	(11)%	3.7%	R2	6 years, 4 months, 24 days
133	Bushy Park - 343	6,474	35 years	(11)%	4.72%	R2	6 years, 2 months, 12 days
134	Bushy Park - 344	65	65 years	(11)%	4.52%	S1	6 years, 3 months, 19 days
135	Bushy Park - 345	418	40 years	(11)%	11.86%	S2	6 years, 4 months, 24 days
136	Bushy Park - 346	121	42 years	(11)%	8.45%	R1	6 years, 3 months, 19 days
137	Total Bushy Park	8,132					
138	Hagood - 341	3,465	55 years	(11)%	1.91%	R2.5	20 years, 2 months, 12 days
139	Hagood - 342	913	55 years	(11)%	1.44%	R2	20 years, 3 months, 19 days
140	Hagood - 343	24,537	35 years	(11)%	1.22%	R2	14 years, 4 months, 24 days
141	Hagood - 344	5,801	65 years	(11)%	1.45%	S1	20 years, 1 month, 6 days
142	Hagood - 345	3,232	40 years	(11)%	2.25%	S2	17 years, 1 month, 6 days
143	Hagood - 345.5	13	40 years	(11)%	5.03%	S2	22 years, 1 month, 6 days
144	Hagood - 346	469	42 years	(11)%	4.3%	R1	19 years, 9 months, 18 days
145	Total Hagood	38,430					
146	Jasper - 341	28,278	55 years	(12)%	3.16%	R2.5	23 years, 10 months, 25 days
147	Jasper - 342	31	55 years	(12)%	4.45%	R2	24 years, 4 months, 24 days
148	Jasper - 343	313,822	35 years	(12)%	2.86%	R2	19 years, 9 months, 18 days
149	Jasper - 344	51,164	65 years	(12)%	3.19%	S1	23 years, 9 months, 18 days
150	Jasper - 345	31,271	40 years	(12)%	3.36%	S2	21 years, 4 months, 24 days
151	Jasper - 345.5	132	40 years	(12)%	4.52%	S2	24 years, 8 months, 12 days
152	Jasper - 346	1,051	42 years	(12)%	4.62%	R1	22 years, 3 months, 19 days

153	Total Jasper	425,749					
154	Urq 1 & 2 - 341	1,272	55 years	(9)%	7.37%	R2.5	10 years, 4 months, 24 days
155	Urq 1 & 2 - 342	193	55 years	(9)%	6.22%	R2	10 years, 2 months, 12 days
156	Urq 1 & 2 - 343	674	35 years	(9)%	7.37%	R2	10 years, 1 month, 6 days
157	Urq 1 & 2 - 344	4,177	65 years	(9)%	6.24%	S1	10 years
158	Urq 1 & 2 - 345	207	40 years	(9)%	8.42%	S2	10 years, 2 months, 12 days
159	Urq 1 & 2 - 346	116	42 years	(9)%	10.38%	R1	10 years
160	Total Urq 1 & 2	6,639					
161	Urq 3 - 341	354	55 years	(9)%	7.37%	R2.5	10 years, 4 months, 24 days
162	Urq 3 - 342	8	55 years	(9)%	6.22%	R2	10 years, 2 months, 12 days
163	Urq 3 - 343	369	35 years	(9)%	7.37%	R2	10 years, 1 month, 6 days
164	Urq 3 - 344	1,946	65 years	(9)%	6.24%	S1	10 years
165	Urq 3 - 345	65	40 years	(9)%	8.42%	S2	10 years, 2 months, 12 days
166	Total Urq 3	2,742					
167	Urq 4 - 341	324	55 years	(10)%	1.01%	R2.5	27 years
168	Urq 4 - 342	211	55 years	(10)%	1.73%	R2	27 years, 3 months, 19 days
169	Urq 4 - 343	4,167	35 years	(10)%	3.52%	R2	25 years, 6 months
170	Urq 4 - 344	19,272	65 years	(10)%	1.85%	S1	27 years, 1 month, 6 days
171	Urq 4 - 345	898	40 years	(10)%	3.59%	S2	27 years, 1 month, 6 days
172	Urq 4 - 346	80	42 years	(10)%	4.12%	R1	25 years, 9 months, 18 days
173	Total Urq 4	24,952					
174	Urq 5 & 6 - 341	5,195	55 years	(12)%	2.22%	R2.5	30 years
175	Urq 5 & 6 - 342	3,603	55 years	(12)%	1.67%	R2	29 years, 1 month, 6 days
176	Urq 5 & 6 - 343	226,392	35 years	(12)%	2.48%	R2	21 years, 2 months, 12 days
177	Urq 5 & 6 - 344	13,383	65 years	(12)%	2.53%	S1	29 years, 8 months, 12 days
178	Urq 5 & 6 - 345	17,240	40 years	(12)%	2.78%	S2	25 years
179	Urq 5 & 6 - 346	289	42 years	(12)%	3.57%	R1	27 years, 6 months
180	Total Urq 5 & 6	266,102					
181	Boeing Solar Project - 341	117	55 years	(10)%	5.71%	R2.5	12 years, 7 months, 6 days
182	Boeing Solar Project - 344	7,031	65 years	(10)%	5.64%	S1	12 years, 7 months, 6 days
183	Boeing Solar Project - 345	2,197	40 years	(10)%	5.68%	S2	12 years, 6 months
184	Boeing Solar Project - 346	18	42 years	(10)%	5.89%	R1	12 years
185	Total Boeing Solar	9,363					
186	Columbia Energy Center - 341 Initial Investment	(f) 4,054					

187	Columbia Energy Center - 342 Initial Investment	[(g)]5,730					
188	Columbia Energy Center - 343 Initial Investment	[(h)]48,202					
189	Columbia Energy Center - 344 Initial Investment	[(i)]90,650					
190	Columbia Energy Center - 345 Initial Investment	[(j)]2,514					
191	Columbia Energy Center - 346 Initial Investment	[(k)]194					
192	Columbia Energy Center - 341	2,104	55 years	(11)%	0.71%	R2.5	34 years, 2 months, 12 days
193	Columbia Energy Center - 342	28	55 years	(11)%	0.56%	R2	33 years, 7 months, 6 days
194	Columbia Energy Center - 343	13,973	35 years	(11)%	0.48%	R2	30 years, 1 month, 6 days
195	Columbia Energy Center - 344		65 years	(11)%	0.33%	S1	34 years, 6 months
196	Columbia Energy Center - 345	1,239	40 years	(11)%	0.3%	S2	32 years, 6 months
197	Columbia Energy Center - 346	1,129	42 years	(11)%	1.26%	R1	30 years, 3 months, 19 days
198	Total Columbia Energy Center	169,817					
199	Hagood ICT U5 341	335	55 years	(12)%	2.61%	R2.5	36 years, 10 months, 25 days
200	Hagood ICT U5 342	337	55 years	(12)%	2.44%	R2	36 years, 1 month, 6 days
201	Hagood ICT U5 343	5,139	35 years	(12)%	1.84%	R2	27 years, 8 months, 12 days
202	Hagood ICT U5 344		0 years			0	30 years
203	Hagood ICT U5 345	2,267	40 years	(12)%	2.99%	S2	29 years, 4 months, 24 days
204	Hagood ICT U5 346		0 years			0	0 years
205	Total Hagood ICT U5	8,078					
206	Hagood ICT U6 341	668	55 years	(12)%	2.55%	R2.5	36 years, 10 months, 25 days
207	Hagood ICT U6 342	419	55 years	(12)%	2.43%	R2	36 years, 1 month, 6 days
208	Hagood ICT U6 343	5,837	35 years	(12)%	2.38%	R2	28 years, 1 month, 6 days
209	Hagood ICT U6 344	4	65 years	(12)%	1.84%	S1	38 years, 3 months, 19 days
210	Hagood ICT U6 345	3,300	40 years	(12)%	2.94%	S2	30 years, 1 month, 6 days
211	Hagood ICT U6 346	63	42 years	(12)%	3.1%	R1	32 years, 1 month, 6 days
212	Total Hagood ICT U6	10,291					
213	Transmission:						
214	Nuclear - 352	169	70 years	(10)%	2.78%	R2	37 years, 2 months, 12 days
215	Other - 352	4,043	70 years	(10)%	0.16%	R2	69 years, 7 months, 6 days
216	Parr - 352	142	70 years	(10)%	0.16%	S0.5	69 years, 7 months, 6 days

217	Saluda - 352	431	70 years	(10)%	0.16%	S0.5	69 years, 7 months, 6 days
218	Columbia Energy Ctr -352	92	70 years	(10)%	0.16%	R2	69 years, 7 months, 6 days
219	Stevens Creek - 352	38	70 years	(20)%	0.16%	S0.5	69 years, 7 months, 6 days
220	Nuclear - 352.5	407	70 years	(10)%	2.69%	R2	40 years, 7 months, 6 days
221	Industrial - 352.5	1,325	70 years	(10)%	1.47%	R2	66 years, 10 months, 25 days
222	FH Station Equip - 353	6,878	60 years	(20)%	1.95%	S0.5	48 years
223	Nuclear - 353	15,456	60 years	(20)%	2.69%	S0.5	34 years, 8 months, 12 days
224	Parr - 353	376	60 years	(20)%	1.32%	S0.5	34 years, 1 month, 6 days
225	Fairfield - 353	1,419	60 years	(20)%	1.13%	S0.5	50 years, 4 months, 24 days
226	Saluda - 353	9,764	60 years	(20)%	1.86%	S0.5	42 years, 10 months, 25 days
227	Stevens Ck - 353	4,667	60 years	(20)%	1.76%	S0.5	41 years, 6 months
228	Neal Shoals - 353	137	60 years	(20)%	2.51%	S0.5	33 years, 7 months, 6 days
229	Nuclear Step-up - 353	13,925	55 years	(20)%	2.38%	S3	37 years, 1 month, 6 days
230	Parr Step-up - 353	397	55 years	(20)%	2.27%	S3	16 years, 10 months, 25 days
231	Fairfield Step-up - 353	7,699	55 years	(20)%	1.94%	S3	42 years, 10 months, 25 days
232	Saluda Step-up - 353	3,252	55 years	(20)%	3.08%	S3	25 years, 6 months
233	Wateree Step-up - 353	5,571	55 years	(20)%	3.59%	S3	25 years, 3 months, 19 days
234	McMeekin Step-up - 353	819	55 years	(20)%	1.68%	S3	16 years, 4 months, 24 days
235	Urquhart Steam Step-up - 353	1,366	55 years	(20)%	6.56%	S3	13 years, 3 months, 19 days
236	Williams Steam Step-up - 353	1,809	55 years	(20)%	2.55%	S3	5 years, 9 months, 18 days
237	Columbia Energy Ctr Int Purchase	24,173	55 years	2,000%	0.65%	n/a	35 years, 6 months
238	Cope Step-up - 353	6,020	55 years	(20)%	2.18%	S3	32 years, 3 months, 19 days
239	Williams GT - 353	5,295	55 years	(20)%	2.55%	S3	5 years, 9 months, 18 days
240	Jasper Step-up - 353	19,101	55 years	(20)%	3.48%	S3	24 years, 7 months, 6 days
241	Burton Step-up - 353		0 years			0	0 years
242	Hardeeville Step-up - 353	118	55 years	(20)%	3.82%	S3	1 year
243	Coit Step-up - 353	118	55 years	(20)%	2.4%	S3	8 years, 2 months, 12 days
244	Hagood Step-up - 353	2,598	55 years	(20)%	2%	S3	32 years, 4 months, 24 days
245	Stevens Creek Step-up - 353	438	55 years	(20)%	1.81%	S3	32 years, 3 months, 19 days
246	Urquhart GT Step-up - 353	978	55 years	(20)%	2.44%	S3	13 years, 3 months, 19 days
247	Bushy Park GT 353 Step-up 353	150	55 years	(20)%	2.55%	S3	5 years, 9 months, 18 days
248	Station Equip - 353	434,678	60 years	(20)%	1.95%	S0.5	48 years
249	Station Equip NND - 353.1	87,557	60 years	(20)%	3.06%	S0.5	38 years, 9 months, 18 days
250	Station Equip CIPV5 - 353.5	16,971	60 years	(20)%	2.01%	S0.5	56 years, 9 months, 18 days

251	Station Equip - Leasehold - 353.8	5,226	20 years		5.01%	SQ	6 years, 6 months
252	354	3,959	80 years	(40)%	1.34%	R3	40 years, 7 months, 6 days
253	Neal Shoals - 354	1	80 years	(40)%	1.34%	R3	40 years, 7 months, 6 days
254	355	588,965	59 years	(75)%	2.97%	L1.5	49 years, 4 months, 9 days
255	Neal Shoals - 355	21	59 years	(75)%	2.97%	L1.5	49 years, 4 months, 9 days
256	NND Trans Poles & Fixtures-355.1	163,979	59 years	(75)%	2.98%	L1.5	21 years, 8 months, 12 days
257	VC Summer Trans Poles & Fixtures-355.1	4,854	59 years	(75)%	2.97%	L1.5	57 years, 9 months, 7 days
258	355.8	2,065	20 years		5.13%	SQ	13 years, 7 months, 6 days
259	356.1	267,300	64 years	(60)%	2.59%	S0.5	51 years, 8 months, 23 days
260	356.2	3,018	64 years	(60)%	2.61%	S0.5	49 years, 2 months, 19 days
261	356.3	115,764	64 years	(60)%	2.53%	S0.5	0 years
262	356.8	2,289	20 years		9.48%	SQ	3 years, 9 months, 18 days
263	357	19,549	60 years	(5)%	1.88%	R3	48 years, 4 months, 24 days
264	358	57,700	55 years	(5)%	2.08%	R3	45 years
265	359	74	70 years		1.29%	R4	56 years, 10 months, 25 days
266	Total Transmission	1,913,141					
267	Distribution Plant:						
268	361	5,226	70 years	(10)%	1.52%	R2	54 years, 4 months, 24 days
269	361.8	38	20 years		5.7%	SQ	1 year
270	362	449,759	60 years	(10)%	1.9%	S0.5	46 years, 2 months, 12 days
271	362.5	752	60 years	(10)%	1.83%	S0.5	58 years, 1 month, 6 days
272	362.8	2,657	20 years		6.21%	SQ	10 years, 3 months, 19 days
273	364	526,712	44 years	(50)%	3.69%	R1.5	32 years, 3 months, 19 days
274	365	583,982	64 years	(10)%	1.5%	R1	52 years, 1 month, 24 days
275	URD - 366	170,665	65 years	(5)%	1.37%	R2.5	52 years, 3 months, 19 days
276	Network - 366	7,663	65 years	(5)%	1.37%	R2.5	52 years, 3 months, 19 days
277	URD - 367	523,804	50 years	(5)%	1.91%	S0.5	39 years, 6 months
278	Network - 367	10,202	50 years	(5)%	1.91%	S0.5	39 years, 6 months
279	368	551,283	46 years	(5)%	2.1%	R2	32 years, 11 days
280	O/H - 369	117,582	75 years	(80)%	2.22%	R3	53 years, 6 months, 3 days
281	U/G - 369.1	208,973	80 years	(25)%	1.44%	S3	63 years, 2 months, 23 days
282	370	26,046	22 years		2.64%	L1.5	16 years, 2 months, 12 days
283	370.3	53,575	15 years		8.39%	S1	7 years
284	370.4	13,948	12 years		11.47%	R0.5	7 years, 3 months, 19 days

285	3705	7,919	12 years		11%	R0.5	8 years
286	3706	75,055	12 years		11.47%	R0.5	7 years
287	373	407,625	42 years	(20)%	2.63%	L1	32 years, 11 months, 15 days
288	373.1		30 years	(20)%	3.94%	S1	26 years, 4 months, 24 days
289	Total Distribution	3,743,466					
290	General Plant:						
291	3901	102,273	50 years	(20)%	2.16%	S0	41 years, 7 months, 6 days
292	3902	10,223	50 years	(20)%	2.35%	R2.5	40 years, 3 months, 19 days
293	3908	145	50 years	(20)%	1.79%	S0	29 years, 2 months, 12 days
294	3909	111	50 years	(20)%	3.68%	R2.5	24 years, 7 months, 6 days
295	3911	8,033	20 years		4.33%	SQ	10 years, 8 months, 12 days
296	3912	1,253	5 years		15.37%	SQ	2 years
297	3913	115	10 years		21.4%	SQ	2 years
298	3915	1,788	5 years		15.37%	SQ	2 years
299	3919		0 years			0	0 years
300	393	80	25 years		3.69%	SQ	9 years, 3 months, 19 days
301	3941	523	20 years		4.76%	SQ	11 years, 8 months, 12 days
302	3942	3,495	20 years		3.99%	SQ	12 years, 7 months, 6 days
303	3943	201	20 years		4.39%	SQ	7 years, 2 months, 12 days
304	3944	242	20 years		6.04%	SQ	9 years, 1 month, 6 days
305	3951	1,892	20 years		3.19%	SQ	11 years, 2 months, 12 days
306	3952	723	20 years		4.52%	SQ	11 years, 7 months, 6 days
307	3953	3,978	20 years		3.62%	SQ	11 years, 8 months, 12 days
308	397	6,031	10 years		7.45%	SQ	8 years, 3 months, 19 days
309	397.5	248	10 years		11.93%	SQ	7 years, 6 months
310	398	6,797	20 years		3.23%	SQ	12 years, 8 months, 12 days
311	Total General Plant	148,151					
312	Solar Farm						
313	341	30	55 years	(6)%	5.84%	R2.5	12 years, 7 months, 6 days
314	346	2	42 years	(6)%	6.06%	R1	12 years
315	Total Solar Farm	32					

FOOTNOTE DATA

(a) Concept: AccountNumberFactorsUsedInEstimatingDepreciationCharges

Method of Determination of Depreciation Charges:

The annual Provision for Depreciation of Property, with the exception of major construction, are based on straight line rates applied to the prior month ending plant balances. The Annual Provision for Depreciation of major construction projects, if any, are computed based on the number of days that the plant was in service.

In addition to Depreciation Provisions provided by the application of the reported rates herein, the Company also recognized $5,812,354 of electric and $445,685 of common depreciation related to vehicles, as well as, $2,484,752 of electric and $3,965,530 of common amortization related to software over their expected useful lives using the straight line method. See allocation of Common Plant on pages 356.1 and 356.2.

The information shown here reflects the 2020 study and plant information filed in the 2021 DESC FERC Form No. 1 filing. We added the solar farm data that was previously omitted in the 2021 DESC FERC Form No. 1 filing'

As indicated in this schedule in the Company's 2020 FERC Form No.1, the Company presented an electric and common plant depreciation study based on plant balances as of December 31, 2018 to the Public Service Commission of South Carolina (SCPSC) for approval in its retail electric base rate proceeding before the SCPSC in

Docket No. 2020-125-E. In the comprehensive settlement agreement approved by the SCPSC in Docket No. 2020-125-E, the SCPSC incorporated certain adjustments proposed by a witness for the South Carolina Office of Regulatory Staff (ORS) to the depreciation study rates presented by the Company. Accordingly, pursuant to the order issued by the SCPSC in Docket No. 2020-125-E, in September 2021 the Company implemented the results of the depreciation study as modified by the witness for the ORS. On March 15, 2022, in Docket No. ER22-1344-000, the Company submitted to the FERC a limited-scope, single issue filing pursuant to Section 205 of the Federal Power Act and Part 35 of the Regulations of the FERC to implement the new depreciation rates in its open access transmission tariff formula rate template. See Docket No. ER22-1344-000 for additional details.

(b) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(c) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(d) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(e) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(f) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(g) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(h) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(i) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(j) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

(k) Concept: DepreciablePlantBase

As indicated in the Company's Federal Power Act Section 203 application in Docket No. EC18-50-000, the Company committed that it would exclude from rate base and rate recovery the initial capital investment in Columbia Energy Center. Therefore, with the account 102 - Electric Plant Purchased or Sold clearing entries approved by the FERC in Docket No. AC18-194-000, the Company recorded an impairment of its initial investment by recognizing a net charge to account 426.5 - Other Deductions with an offsetting credit to account 108 - Accumulated Provisions for Depreciation of Electric Utility Plant and an offsetting debit to account 114 - Electric Plant Acquisition Adjustments. Since the initial investment was fully written down, no additional depreciation is necessary on this balance.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.
3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in columns (f), (g), and (h), expenses incurred during the year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

						EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR		
						CURRENTLY CHARGED TO						
Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses for Current Year (d)	Deferred in Account 182.3 at Beginning of Year (e)	Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)
1	State assessment for the support of the Public Service Commission of South Carolina (SCPSC)	5,118,129		5,118,129		Electric	928	5,118,129				
2	Annual charges assessed by the Federal Energy Regulation Commission (FERC)	1,983,643		1,983,643		Electric	928	1,983,643				
3	Company labor, legal, consulting and miscellaneous expenses related to the Company's retail electric base rate case before the SCPSC. Amortization period September 2021 - July 2037. SCPSC Docket No. 2020-125-E		33,885	33,885	2,796,792	Electric	928	33,885	2,055	928	180,048	2,618,799
4	Company labor, legal and consulting expenses related to the Company's avoided cost methodology proceeding before the SCPSC. SCPSC Docket Nos. 2019-184-E and 2021-88-E		434,396	434,396		Electric	928	434,396				
5	Company labor, legal, consulting and miscellaneous expenses related to the Company's annual review of base fuel rates before the SCPSC. SCPSC Dockets No. 2021-2-E, 2022-2-E, and 2022-259-E		408,972	408,972		Electric	928	408,972				
6	Company labor related to the Company's Integrated Resource Plan before the SCPSC. SCPSC Docket No. 2022-9-E		301,679	301,679		Electric	928	301,679				
7	Company labor related to the Company's transmission filings before the FERC. FERC Docket Nos. ER10-516, ER10-855, ER10-1268, ER20-1836 and ER22-1344		16,463	16,463		Electric	928	16,463				
8	Company labor and legal expenses related to the FERC Audit of Dominion Energy Services, Inc. and Dominion Energy Southeast Services, Inc. FERC Docket No. FA22-4-000		106,370	106,370		Electric	928	106,370				
9	Company labor, legal, consulting and miscellaneous expenses related to proceedings. Various Dockets		274,543	274,543		Electric	928	274,543				
46	TOTAL	7,101,772	1,576,308	8,678,080	2,796,792			8,678,080	2,055		180,048	2,618,799

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D and D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D and D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:
   Classifications:

A. Electric R, D and D Performed Internally:

1. Generation
   a. hydroelectric
      i. Recreation fish and wildlife
      ii. Other hydroelectric
   b. Fossil-fuel steam
   c. Internal combustion or gas turbine
   d. Nuclear
   e. Unconventional generation
   f. Siting and heat rejection
2. Transmission
   a. Overhead
   b. Underground
3. Distribution
4. Regional Transmission and Market Operation
5. Environment (other than equipment)
6. Other (Classify and include items in excess of $50,000.)
7. Total Cost Incurred

B. Electric, R, D and D Performed Externally:

1. Research Support to the electrical Research Council or the Electric Power Research Institute
2. Research Support to Edison Electric Institute
3. Research Support to Nuclear Power Groups
4. Research Support to Others (Classify)
5. Total Cost Incurred

3. Include in column (c) all R, D and D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D and D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D and D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e).
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D and D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by ""Est.""
7. Report separately research and related testing facilities operated by the respondent.

Line No.	Classification (a)	Description (b)	Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Account (e)	AMOUNTS CHARGED IN CURRENT YEAR: Amounts Charged In Current Year: Amount (f)	Unamortized Accumulation (g)
1	A. Electric R, D, & D Performed Internally:						
2	(1) Generation	Coordination of EPRI and other RD&D activities (5 Items under $50,000)					
3	(2) Transmission	Coordination of EPRI and other RD&D activities (5 Items under $50,000)					
4	(3) Distribution	Coordination of EPRI and other RD&D activities (5 Items under $50,000)					
5	B. Electric R, D, & D Performed Externally:						
6	(1) Research Support to EPRI						
7	Fossil Steam Plants and Combustion						
8	Turbine Programs	Heat Recovery Steam Generators		43,368	930.2	43,368	
9		Hydropower Generation		43,368	930.2	43,368	
10		Power Plant Piping		43,368	930.2	43,368	
11		Gas Turbine Life Cycle Management		43,368	930.2	43,368	
12		Integrated Asset Management		43,368	930.2	43,368	
13		Plant Management Essentials		43,367	930.2	43,367	
14		Boiler and Turbine Steam and Cycle Chemistry		43,367	930.2	43,367	

15		Water Treatment Technologies		43,367	930.2	43,367	
16		Steam Turbines and Auxiliary Systems		85,903	930.2	85,903	
17		Generators and Auxiliary Systems		85,903	930.2	85,903	
18	Transmission and Substation - Programs	Transmission Asset Management Analytics: Principles and Practices		1,916	930.2	1,916	
19		Substations Asset Data Analytics		16,051	930.2	16,051	
20		Overhead Transmission Asset Data Analytics		9,500	930.2	9,500	
21		Inspection and Assessment		10,525	930.2	10,525	
22		Structure and Sub-Grade Corrosion Management		11,652	930.2	11,652	
23		Lightning Performance and Grounding of Transmission Lines		19,733	930.2	19,733	
24		Line Design Tools and Practices for Construction and Management		15,787	930.2	15,787	
25		Modeling and Analytics for Emerging Technologies		32,237	930.2	32,237	
26		Operator Support Tools and Methods for Emerging Technologies		32,237	930.2	32,237	
27		Emerging Technologies and Technology Transfer		23,430	930.2	23,430	
28		Polymer and Composite Overhead Transmission Line Insulators		17,854	930.2	17,854	
29		Overhead Line Ratings and Increased Power Flow		12,404	930.2	12,404	
30		High Temperature Operation of Overhead Lines		14,471	930.2	14,471	
31		Line Switch Mangement		9,585	930.2	9,585	
32		Principles and Practices of Underground Transmission		9,846	930.2	9,846	
33		Transformer Life Management		66,508	930.2	66,508	
34		Balance of Substations: Batteries, CCVT's, Arresters, & Ratings		11,048	930.2	11,048	
35		Advanced Metering Systems		41,003	930.2	41,003	
36	Power Quality and Renewables Programs	Bulk Energy Storage		43,368	930.2	43,368	
37		Solar Generation		43,368	930.2	43,368	
38		Achieving Cost-Effective Edge-of-Grid PQ Compatibility		38,918	930.2	38,918	
39	Nuclear Power Programs	Nuclear Power		510,514	930.2	510,514	
40	Nuclear Supplemental Projects	SGMP - Steam Generator Management Program		68,837	524.0	68,837	
41		MRP - Materials Reliability Program		159,008	524.0	159,008	
42		STE - Standardized Task Evaluations for Portable Qualifications		18,290	524.0	18,290	
43		External Hazards Data Collection		8,000	524.0	8,000	
44		Low Level Waste Technical Strategy Group		24,668	524.0	24,668	
45		Radiation Management and Source Term Technical Strategy		26,668	524.0	26,668	
46		Pressurized Water Reactor Technical Strategy Group		7,334	524.0	7,334	
47		FTREX		3,200	524.0	3,200	
48		Value Based Maintenance		2,867	524.0	2,867	
49		Risk-Informed Classification & Treatment		6,667	524.0	6,667	

50		Digital Systems Engineering Users Group		6,667	524.0	6,667	
51		Fuel Reliability Program		77,471	524.0	77,471	
52	(4) Research Support to Others						
53	Clemson University Electric Power Research Alliance	CUEPRA		30,000	588.0	30,000	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	51,156,557		
4	Transmission	6,828,587		
5	Regional Market			
6	Distribution	13,194,571		
7	Customer Accounts	9,268,515		
8	Customer Service and Informational	2,345,127		
9	Sales	1,060,575		
10	Administrative and General	60,160,741		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	144,014,673		
12	Maintenance			
13	Production	20,930,815		
14	Transmission	2,503,274		
15	Regional Market			
16	Distribution	12,019,809		
17	Administrative and General	606,083		
18	TOTAL Maintenance (Total of lines 13 thru 17)	36,059,981		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	72,087,372		
21	Transmission (Enter Total of lines 4 and 14)	9,331,861		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,214,380		
24	Customer Accounts (Transcribe from line 7)	9,268,515		
25	Customer Service and Informational (Transcribe from line 8)	2,345,127		
26	Sales (Transcribe from line 9)	1,060,575		
27	Administrative and General (Enter Total of lines 10 and 17)	60,766,824		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	180,074,654		180,074,654
29	Gas			
30	Operation			
31	Production - Manufactured Gas			
32	Production-Nat. Gas (Including Expl. And Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission	2,853		
36	Distribution	15,240,944		
37	Customer Accounts	3,937,965		
38	Customer Service and Informational	552,570		
39	Sales	1,582,753		
40	Administrative and General	11,365,524		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	32,682,609		
42	Maintenance			
43	Production - Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			
48	Distribution	2,501,515		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,501,515		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)	2,853		
57	Distribution (Lines 36 and 48)	17,742,459		
58	Customer Accounts (Line 37)	3,937,965		
59	Customer Service and Informational (Line 38)	552,570		
60	Sales (Line 39)	1,582,753		
61	Administrative and General (Lines 40 and 49)	11,365,524		

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	35,184,124		35,184,124
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	215,258,778		215,258,778
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant		48,585,070	48,585,070
69	Gas Plant		9,957,121	9,957,121
70	Other (provide details in footnote):		2,076,525	[a]2,076,525
71	TOTAL Construction (Total of lines 68 thru 70)		60,618,716	60,618,716
72	Plant Removal (By Utility Departments)			
73	Electric Plant		14,359,717	14,359,717
74	Gas Plant		619,152	619,152
75	Other (provide details in footnote):		13,544	[b]13,544
76	TOTAL Plant Removal (Total of lines 73 thru 75)		14,992,413	14,992,413
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Non Utility Property	4,218		4,218
80	Non Operating Expenses	521,509		[c]521,509
81	Other Work in Progress	1,033,473		1,033,473
82	Other Balance Sheet Payroll (provide details in footnote)	2,951,029		[d]2,951,029
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	4,510,229		4,510,229

96	TOTAL SALARIES AND WAGES	219,769,007	75,611,129	[a]295,380,136

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: SalariesAndWagesUtilityPlantConstructionOther

Common Plant

(b) Concept: SalariesAndWagesPlantRemovalOther

Common Plant

(c) Concept: SalariesAndWagesOtherAccounts

Other Deductions

(d) Concept: SalariesAndWagesOtherAccounts

Demand Side Management (DSM) Deferrals, Regulatory Assets, Preliminary Survey and Investigation, Accounts Receivable for insurance claims.

(e) Concept: SalariesAndWagesGeneralExpense

Amounts reported on pages 354 and 355 exclude incentive compensation.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

Common Utility Plant In Service		Balance End of Year
118-603 Misc Intangible Plant	$	146,397,142
118-689 Land and Land Rights		12,540,930
118-690 Structures and Improvements		193,085,290
118-691 Office Furniture and Equipment		11,251,887
118-692 Transportation Equipment		2,432,529
118-694 Tools, Shop and Garage Equipment		1,872,431
118-695 Laboratory Equipment		17,847
118-696 Power-Operated Equipment		26,289,461
118-697 Communication Equipment		12,986,844
118-698 Miscellaneous Equipment		8,036,991
118-699 ARC Common Gen Plant		3,749
	$	414,915,101

Note: Common Plant in service consists of land and buildings devoted jointly to all utility operations, such as general office buildings, storerooms and repair shops and equipment therein. Also, software and transportation equipment used jointly is thus classified.

As a result of the adoption of new accounting guidance for leases in 2019, Common Utility Plant includes the following balances for operating leases as of December 31, 2021:

Plant Account		Balance End of Year
689 - Land and Land Rights	$	9,173,879
690 - Structures and Improvements		1,473,051
691 - Office Furniture and Equipment		292,419
697 - Communication Equipment		2,148,542
Total	$	13,087,891

For the formula rate approved in the FERC proceeding listed on page 106, Common Utility Plant will exclude the operating lease balances identified above.

Construction Work in Progress - Common Utility Plant

Description of Project		Balance End of Year
Builder Portal	$	1,218,773
CIS Service Order Architecture		793,112
ASR/TTS Replacement (IRV Enchancement)		617,318
AMI Data Presentment		456,820
AMI Revenue Assurance		436,597
Other Projects < $400,000		8,658,232
Total	$	12,180,852

Common Plant in Service and Depreciation Reserve

Allocable to Utility Departments

Common Utility	Total (a)	Electric (b)	Gas (c)
Plant Allocable to Utility department (1)	$414,915,101	$371,929,896	$42,985,205
Less:			
Common Depreciable Reserve Allocable to Utility Department (2)	193,665,445	173,601,705	20,063,740
Net Common Plant Allocable to Utility Departments	$221,249,656	$198,328,191	$22,921,465

(1) This allocation is based on functional use by Departments.
Allocation: Electric 89.64% and Gas 10.36%
(2) This allocation is based on functional use by Departments of common depreciable property.
Allocation is the same as in note (1)

Common Utility Plant Expenses are not segregated, but charged to utility departments on a functional basis.

Common Utility Plant Classification July 24, 1948.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				165,312
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services	1	(6)	(6)	(4)
6	Other Items (list separately)				
7	Real-Time Load Response Charge Allocation	1	1	1	1
8	PJM Settlement, Inc.	161	385	464	619
9	Estimated Transmission for December 2022 - To be reversed and actualized in January 2023				1,340
46	TOTAL	163	380	459	167,268

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.
In columns for usage, report usage-related billing determinant and the unit of measure.

1. On Line 1 columns (b), (c), (d), and (e) report the amount of ancillary services purchased and sold during the year.
2. On Line 2 columns (b), (c), (d), and (e) report the amount of reactive supply and voltage control services purchased and sold during the year.
3. On Line 3 columns (b), (c), (d), and (e) report the amount of regulation and frequency response services purchased and sold during the year.
4. On Line 4 columns (b), (c), (d), and (e) report the amount of energy imbalance services purchased and sold during the year.
5. On Lines 5 and 6, columns (b), (c), (d), and (e) report the amount of operating reserve spinning and supplement services purchased and sold during the period.
6. On Line 7 columns (b), (c), (d), and (e) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollar (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	[a]0	[b]0	[c]615	89,277	MW	176,259
2	Reactive Supply and Voltage	[d]0	[e]0	[f]2,439	89,277	MW	392,291
3	Regulation and Frequency Response	[g]0	[h]0	[i]182	1,615	MW	74,458
4	Energy Imbalance	[j]426	[k]MWH	[l]56,296	[m]2,120	MWH	[n]19,523
5	Operating Reserve - Spinning	[o]0	[p]0	[q]385	1,855	MW	122,299
6	Operating Reserve - Supplement	[r]0	[s]0	[t]390	1,855	MW	177,772
7	Other	[u]0	[v]0	[w]6,190	0		
8	Total (Lines 1 thru 7)	426		66,497	[x]185,999		[y]962,602

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.1, Column D for detail on number of units.

(b) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.1, Column D for detail on units of measure.

(c) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 1	0.063178	% Load Ratio Share	$	40
Duke Energy Carolinas, LLC OATT Rate Schedule 1	97 MW/ 97 MWH	MW, MWH		11
Duke Energy Progress, Inc. OATT Rate Schedule 1	400 MW/ 400 MWH	MW, MWH		100
PJM Settlement, Inc.	0 MW/ 0 MWH	MW, MWH		—
Santee Cooper OATT Rate Schedule 1	1975 MW/ 1917 MWH	MW,MWH		464
		Total	$	615

(d) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.1, Column D for detail on number of units.

(e) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.1, Column D for detail on units of measure.

(f) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 2	0.063178	% Load Ratio Share	$	958
Duke Energy Carolinas, LLC OATT Rate Schedule 2	97 MW/ 97 MWH	MW,MWH		27
Duke Energy Progress, LLC OATT Rate Schedule 2	400 MW/ 400 MWH	MW,MWH		240
PJM Settlement, Inc.	0 MW/ 0 MWH	MW,MWH		1
Santee Cooper OATT Rate Schedule 2	1975 MW/ 1917 MWH	MW,MWH		1,213
		Total	$	2,439

(g) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.1, Column D for detail on number of units.

(h) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.1, Column D for detail on units of measure.

(i) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 3	0.063178	% Load Ratio Share	$	182

(j) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.4, Column D for detail on number of units.

(k) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.4, Column D for detail on units of measure.

(l) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 4	426	MWH	$	56,296
		Total	$	56,296

(m) Concept: AncillaryServicesSoldNumberOfUnits

Energy Imbalance breakdown by MWH:

Gross Band 1	Over Supplied	Under Supplied*
1,230	428	462

(n) Concept: AncillaryServicesSoldAmount

Energy Imbalance breakdown by dollar amount:

Net Band 1	Over Supplied	Under Supplied*
$12,779	$(32,736)	$39,481

* Reported value for Under Supplied is net of Energy Imbalance Penalties credited to users of the transmission system.

(o) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.5, Column D for detail on number of units.

(p) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.5, Column D for detail on units of measure.

(q) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 5	0.063178	% Load Ratio Share	$	390
PJM Settlement, Inc.	0 MW/ 0 MWH			(5)
		Total	$	385

(r) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.6, Column D for detail on number of units.

(s) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.6, Column D for detail on units of measure.

(t) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Rate Schedule 6	0.063178	% Load Ratio Share	$	390

(u) Concept: AncillaryServicesPurchasedNumberOfUnits

Reference footnote Line No.7, Column D for detail on number of units.

(v) Concept: AncillaryServicesPurchasedNumberOfUnitsPower

Reference footnote Line No.7, Column D for detail on units of measure.

(w) Concept: AncillaryServicesPurchasedAmount

Name	# of Units	Unit of Measure		Amount
Duke Energy Carolinas, LLC OATT Direct Assignment Charges and Other Miscellaneous Adjustments.			$	5,430
Duke Energy Carolinas, LLC loss related to January 2022 Purchase Wheeling transaction				140
Real Time Load Response Change Allocation Change Allocation				1
PJM Settlement, Inc. Miscellaneous Fees				619
Total		Total	$	6,190

(x) Concept: AncillaryServicesSoldNumberOfUnits

Total is not meaningful due to the summation of dissimilar units of measure.

(y) Concept: AncillaryServicesSoldAmount

Ancillary Services revenue reported on this schedule is reported as necessary in other supporting schedules within this Form 1 filing.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

1. Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
	NAME OF SYSTEM: 0									
1	January	3,755	27	[(a)]8	[(b)]3,442	246			67	
2	February	3,749	9	8	3,498	251				
3	March	3,401	14	8	3,177	224				
4	Total for Quarter 1				10,117	721			67	
5	April	3,439	25	18	3,059	176			204	
6	May	4,343	19	17	4,000	241			102	
7	June	4,990	13	17	4,449	266			275	
8	Total for Quarter 2				11,508	683			581	
9	July	4,633	29	18	4,281	255			97	
10	August	4,633	2	18	4,371	262				
11	September	4,143	22	17	3,947	196				
12	Total for Quarter 3				12,599	713			97	
13	October	3,035	17	18	2,777	156			102	
14	November	3,345	18	8	3,121	224				
15	December	4,594	24	8	4,309	285				
16	Total for Quarter 4				10,207	665			102	
17	Total				44,431	2,782			847	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: HourOfMonthlyPeakExcludingIsoAndRto
All times shown in Hour Ending (HE) format.
(b) Concept: FirmNetworkServiceForSelf
For all values shown in column (e): The Company utilizes grandfathered service for its retail customers and has not executed a network integration transmission service agreement under the OATT.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Monthly ISO/RTO Transmission System Peak Load

1. Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
2. Report on Column (b) by month the transmission system's peak load.
3. Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
4. Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
5. Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Import into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
	NAME OF SYSTEM: 0									
1	January									
2	February									
3	March									
4	Total for Quarter 1				0	0	0	0	0	0
5	April									
6	May									
7	June									
8	Total for Quarter 2				0	0	0	0	0	0
9	July									
10	August									
11	September									
12	Total for Quarter 3				0	0	0	0	0	0
13	October									
14	November									
15	December									
16	Total for Quarter 4				0	0	0	0	0	0
17	Total Year to Date/Year				0	0	0	0	0	0

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	[a][b]21,820,395
3	Steam	4,300,279	23	Requirements Sales for Resale (See instruction 4, page 311.)	825,078
4	Nuclear	5,727,321	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	334,215
5	Hydro-Conventional	245,071	25	Energy Furnished Without Charge	[c]0
6	Hydro-Pumped Storage	433,370	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	75,044
7	Other	9,798,253	27	Total Energy Losses	1,098,485
8	Less Energy for Pumping	603,417	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	19,900,877	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	24,153,217
10	Purchases (other than for Energy Storage)	4,237,761			
10.1	Purchases for Energy Storage	0			
11	Power Exchanges:				
12	Received	0			
13	Delivered	0			
14	Net Exchanges (Line 12 minus line 13)	0			
15	Transmission For Other (Wheeling)				
16	Received	[d]547,483			
17	Delivered	[e]532,904			
18	Net Transmission for Other (Line 16 minus line 17)	14,579			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	24,153,217			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 2023-03-24	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: MegawattHoursSoldSalesToUltimateConsumers

Sales to Ultimate Customers includes 8 megawatt hours of Energy Furnished Without Charge. This was done to be in line with the Taxonomy provided by FERC to ensure the total here agrees with page 300-301, Line 10 Column D.

(b) Concept: MegawattHoursSoldSalesToUltimateConsumers

Includes Unmetered MWH Sales as follows:

Residential	75,188
Commercial/Industrial	141,502
Street Lighting	61,046
Other Public Authorities	699
	278,435

(c) Concept: NonChargedEnergy

Sales to Ultimate Customers includes 8 megawatt hours of Energy Furnished Without Charge. This was done to be in line with the Taxonomy provided by FERC to ensure that Line 22 above agrees with page 300-301, Line 10 Column D.

(d) Concept: ElectricPowerWheelingEnergyReceived

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from DESC's system. The MWH supporting these transactions are included in DESC's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j).

The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,396,729	1,357,982
Page 401a	547,483	532,904
Difference	849,246	825,078

DESC Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 10	789,512	766,516
Page 329 line 11	59,734	58,562
Total	849,246	825,078

(e) Concept: ElectricPowerWheelingEnergyDelivered

Certain transactions reported in account 456.1 – Transmission of Electricity for Others were supplied with generation from DESC's system. The MWH supporting these transactions are included in DESC's net generation total on line 9. Therefore, the totals on page 401a lines 16 and 17 do not agree with the totals reported on page 329 columns (i) and (j).

The differences can be reconciled as follows:

	MWH Received	MWH Delivered
Page 329	1,396,729	1,357,982
Page 401a	547,483	532,904
Difference	849,246	825,078

DESC Supplied Energy to Network and PtP Customers

	MWH Received	MWH Delivered
Page 329 line 10	789,512	766,516
Page 329 line 11	59,734	58,562
Total	849,246	825,078

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirement Sales for Resale & Associated Losses (c)	Monthly Peak - Megawatts (d)	Monthly Peak - Day of Month (e)	Monthly Peak - Hour (f)
	NAME OF SYSTEM: 0					
29	January	[a]2,139,766		4,255	23	[b]8
30	February	1,689,269		4,022	9	8
31	March	1,697,259	7,573	3,524	14	8
32	April	1,741,829	114,933	3,239	25	18
33	May	2,095,961	55,618	4,243	19	17
34	June	2,344,402	49,526	4,723	13	17
35	July	2,497,280	34,511	4,569	7	16
36	August	2,364,046	14,890	4,634	2	18
37	September	2,050,722	13,347	4,292	22	17
38	October	1,739,666	31,433	3,014	12	17
39	November	1,741,936	15,248	3,571	18	8
40	December	2,052,095	12,326	4,680	24	10
41	Total	24,154,231	349,405			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: EnergyActivity
Certain amounts have been updated from amounts originally reported in quarterly filings.
(b) Concept: HourOfMonthlyPeak
All Times are in Hour Ending (HE) format.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Steam Electric Generating Plant Statistics

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
9. Items under Cost of Plant are based on USofA accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Line No.	Item (a)	Plant Name: Boeing	Plant Name: Canadys	Plant Name: Coit #1 Peaking Unit	Plant Name: Coit #2 Peaking Unit	Plant Name: Coit Combined	Plant Name: Columbia Energy Center	Plant Name: Cope	Plant Name: Hagood #4	Plant Name: Hagood #5	Plant Name: Hagood #6	Plant Name: Hagood Combined
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	[(a)] Solar Photovoltaic	[(b)] Steam	Gas Turbine	Gas Turbine		Combined Cycle	Steam	Gas Turbine	Gas Turbine	Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Full-Outdoor	Outdoor-Boiler	Package	Package		Package	Conventional	Package	Package	Package	
3	Year Originally Constructed	2011	1962	1969	1969		2004	1996	1991	2000	1981	
4	Year Last Unit was Installed	2011	1967	1969	1969		2004	1996	1991	2000	1981	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	[(f)] 0.00	19.64	19.64	39.27	668.50	417.36	121.89	27.40	27.94	177.23
6	Net Peak Demand on Plant - MW (60 minutes)			13	11	24	561	527	90	20	24	134
7	Plant Hours Connected to Load			71	73	144	7,861	6,957	303	309	309	921
8	Net Continuous Plant Capability (Megawatts)											
9	When Not Limited by Condenser Water			18	18		621	415	95	21	21	

Line No.	Item (a)	Plant Name: Hardeeville Peaking	Plant Name: Jasper	Plant Name: Major Maintenance Accrual	Plant Name: McMeekin	Plant Name: Parr #1 & #2	Plant Name: Parr #3 & #4	Plant Name: Parr Combined	Plant Name: Urquhart	Plant Name: Urquhart #1 Peaking	Plant Name: Urquhart #2 Peaking
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Combined Cycle	[(c)] footnote	Steam	Gas Turbine	Gas Turbine		Steam	Gas Turbine	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Package	Package		Semi-Outdoor	Package	Package	[(e)] See footnote	Conventional	Package	Package
3	Year Originally Constructed	1968	2004		1958	1970	1971		1953	1969	1969
4	Year Last Unit was Installed	1968	2004		1958	1970	1971		1955	1969	1969
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	1,082.10		293.76	39.10	44.54	83.64	100.00	19.64	16.32
6	Net Peak Demand on Plant - MW (60 minutes)		957		262	16	39	55	95	12	13
7	Plant Hours Connected to Load		22,408		6,806	94	110	204	1,537	65	36
8	Net Continuous Plant Capability (Megawatts)										
9	When Not Limited by Condenser Water	0	961		250	17	39	0	96	16	17

10	When Limited by Condenser Water			14	12		519	415	88	18	20		0	903		250	14	33	0	95	13	14
11	Average Number of Employees		0	[g]0	[h]0	[i]0	26	60	[j]0	[k]0	[l]0	[m]0	[n]0	34		36	[o]0	[p]0	2	46	[q]0	[r]0
12	Net Generation, Exclusive of Plant Use - kWh			639,000	512,000	1,151,000	2,712,500,000	1,722,555,000	19,857,000	4,381,000	5,134,000	29,372,000		5,080,154,000		755,990,000	1,225,000	2,567,000	3,792,000	42,205,000	585,000	338,000
13	Cost of Plant: Land and Land Rights		5,530,554	36,023	27,736	63,759		3,214,010	96,047			96,047	5,261	2,736,178		15,668	9,701	6,150	15,851	2,616,353	0	
14	Structures and Improvements			78,164	69,100	147,264	4,100,472	82,801,606	3,483,944	335,181	672,533	4,491,658		28,222,010		23,312,491	373,270	517,033	890,303	19,270,483	516,231	404,329
15	Equipment Costs			3,546,828	2,721,909	6,268,737	271,244,925	533,877,933	34,995,602	7,799,043	9,694,349	52,488,994		510,789,443		181,750,292	7,566,430	4,516,700	12,083,130	116,755,163	2,085,449	859,385
16	Asset Retirement Costs							2,440,610	(5,796,001)			(5,796,001)				3,176,848				10,910,336	0	
17	Total cost (total 13 thru 20)		5,530,554	3,661,015	2,818,745	6,479,760	275,345,397	622,334,159	32,779,592	8,134,224	10,366,882	51,280,698	5,261	541,747,631		208,255,299	7,949,401	5,039,883	12,989,284	149,552,335	2,601,680	1,263,714
18	Cost per KW of Installed Capacity (line 17/5) Including			186.4061	143.5206	165.0053	411.8854	1,491.1208	268.9277	296.8695	371.0409	289.3455		500.6447		708.9301	203.3095	113.1541	155.2999	1,495.5234	132.4684	77.4335
19	Production Expenses: Oper, Supv, & Engr					1,154	762,753	2,304,485				13,519		1,197,796	0	585,037			14,741	16,794		
20	Fuel					527,867	166,598,828	118,960,811				5,017,184		303,231,276	0	72,655,711			236,919	2,813,355		
21	Coolants and Water (Nuclear Plants Only)														0							
22	Steam Expenses							3,173,746							0	1,442,815				691		
23	Steam From Other Sources														0							
24	Steam Transferred (Cr)														0							
25	Electric Expenses	7,605				6,396	2,015,377	205,940				8,493		2,344,708	0	1,103,083			129,808	96,520		
26	Misc Steam (or Nuclear) Power Expenses							1,280,072							0	667,606				22,444		
27	Rents														0							

28	Allowances						10							16	0	3						
29	Maintenance Supervision and Engineering					22	938,859	4,941				67,151		393,852	0	255,342			528	8,885		
30	Maintenance of Structures						1,674	240,709				7,651		130		127,513				9,623		
31	Maintenance of Boiler (or reactor) Plant							2,189,527							(324,633)	982,428				2,503		
32	Maintenance of Electric Plant					18,701	6,709,385	220,371				11,526		17,009,654	(3,933,468)	1,695,237			23,180	54,890		
33	Maintenance of Misc Steam (or Nuclear) Plant					5,989	682,507	1,571,060				77,938		151,532	2,673,492	421,379			209	16,408		
34	Total Production Expenses	7,605	0			560,129	177,709,393	130,151,662	0			5,203,462		324,328,964	(1,584,609)	79,936,154			405,385	3,042,113	0	
35	Expenses per Net kWh					0.4866	0.0655	0.0756				0.1772	0	0.0638		0.1057			0.1069	0.0721	0	

35	**Plant Name**	Coit Combined	Coit Combined	Columbia Energy Center	Columbia Energy Center	Cope	Cope	Cope	Hagood Combined	Hagood Combined	Jasper	Jasper	McMeekin	McMeekin	Parr Combined	Parr Combined	Urquhart	Urquhart	Urquhart Combined 1-4	Urquhart Combined 1-4	Urquhart Combined Cycle	Urquhart Combined Cycle	V.C. Summer (2/3rds)	Wateree	Wate
36	Fuel Kind	Gas	Oil	Gas	Oil	Coal	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Nuclear	Coal	Oil
37	Fuel Unit	Mcf	bbl	Mcf	bbl	T	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	Mcf	bbl	g	T	bbl
38	Quantity (Units) of Fuel Burned	2,089	4,196	18,962,791	3,143	207,962	11,451,951	2,236	263,171	18,602	36,393,832	1,545	7,592		25,151	5,585	474,675		180,474	5,490	14,961,512	27,213	903,902	756,900	33,
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1,033	142,000	1,035	142,000	12,034	1,034	142,000	1,029	142,000	1,027	142,000	1,029		1,010	142,000	1,037		1,033	142,000	1,036	142,000	65	12,463	142,
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	9.996	184.822	8.390	174.147	120.594	7.969	167.074	9.882	165.892	8.776		9.278		8.969		9.079	190.933	38.2140		7.8820			98.726	179.
41	Average Cost of Fuel per Unit Burned	9.996	116.210	8.390	214.371	98.548	7.969	124.437	9.882	121.070	8.776	47.457	9.278		8.969	0.842	9.079		38.2140	139.5790	7.8820	17.8430	42.67	91.355	156.
42	Average Cost of Fuel Burned per Million BTU	9.677	19.485	8.106	35.944	4.095	7.708	20.865	9.602	20.300	8.542	7.957	9.017		8.878	0.141	8.751		36.9940	23.4040	7.6110	2.9920	0.647	3.665	26.
43	Average Cost of Fuel Burned per kWh Net Gen	0.522	0.445	(y) 0.059		(z) 0.065			0.127	0.252	(aa) 0.063		0.093		0.140	0.002	(ab) 0.102		0.4430	0.1580	(ac) 0.0670		(ad) 0.007	(ae) 0.041	

44	Average BTU per kWh Net Generation					[af] 10,180.000							10,177.000				[ag] 11,679.000						[ah] 10,243.000	[ai] 10,573.000	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind

This is a rooftop mounted solar electric generator that provides electricity exclusively for use by a large industrial customer. None of the output flows onto the grid.

(b) Concept: PlantKind

In December 2012, the Company retired the 90MW Unit 1 at Canadys Station. In November 2013, the Company retired the remaining units, Unit 2 (115MW) and Unit 3 (180MW).

(c) Concept: PlantKind

The major maintenance accrual represents an SCPSC approved (SCPSC Docket Nos. 2009-489-E, 2012-218-E, 2017-210-E and 2020-125-E) annual turbine-generator maintenance expense accrual. Prior to September 2021, the annual accrual was $18.4 million. Effective September 2021, the SCPSC approved an annual accrual of $24.8 million. Under this mechanism, the Company records an annual expense accrual of $24.8 million and records any difference between actual expenses incurred and this accrual as a regulatory asset or liability as appropriate. For the year ended December 31, 2021 the Company incurred actual expenses of $20.4 million for major maintenance that is subject to the accrual. Cumulative costs for turbine- generator maintenance in excess of cumulative collections (accruals) are classified as a regulatory asset on the balance sheet.

(d) Concept: PlantKind

SCE&G's portion (two-thirds) of jointly owned plant.

Instruction No. 12 - V. C. Summer Nuclear Station

(a) Nuclear fuel amortization, which is included in Production Expenses, is recorded using the units-of-production method. Normal operation and maintenance costs are charged to expenses as incurred with appropriate application of the accrual method of accounting. Pursuant to an order issued by the Public Service Commission of South Carolina (SCPSC), estimated refueling outage operation and maintenance costs for the five outages from Spring 2014 through Spring 2020 were being accrued over the 90 month period (January 2013 through June 2020) covered by these outages. By Order dated November 24, 2020, issued in Docket No. 2020-172-E, the SCPSC authorized the Company to continue to recognize a levelized nuclear outage accrual and explained that the Company will address the accrual in its then upcoming electric base rate filing. By Order No. 2021-570 issued in Docket No. 2020-125-E, the SCPSC approved the Company's request to extend the outage accrual mechanism for another five outages covering the period July 2020 through December 2027.

(b) Cost is recorded for nuclear fuel on the batch basis. At reload, the number of new assemblies required to complete the core requirement of 157 assemblies is designated as the new batch. All costs for this new batch are reported according to classification of component by batch number. Each batch consists of costs for U308, conversion, enrichment, fabrication, and allowance for funds used during construction.

(c) The V. C. Summer Nuclear Station is a Westinghouse PWR Nuclear Power Plant. Fuel material is U02 contained in zirconium alloy tube cladding. The equilibrium cycle has approximately 65.5 metric tons of Uranium metal with a nominal U-235 enrichment of 4.6% to 4.8%. The reactor is licensed to allow operation of 2900 MWt.

(e) Concept: PlantConstructionType

Parr Steam Plant functions in a combined cycle operation with four gas turbine peaking units and two heat recovery boilers. Production expenses and fuel data are for the entire operation. See column (e), lines 19-44 for combined data on Parr units.

(f) Concept: InstalledCapacityOfPlant

There are no remaining units in service. Therefore, no installed capacity is being reported for this plant.

(g) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(h) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(i) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(j) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(k) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(l) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(m) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(n) Concept: PlantAverageNumberOfEmployees

Unattended-automatic.

(o) Concept: PlantAverageNumberOfEmployees

Employees not specifically assigned to individual units.

(p) Concept: PlantAverageNumberOfEmployees
Employees not specifically assigned to individual units.
(q) Concept: PlantAverageNumberOfEmployees
Employees not specifically assigned to individual units.
(r) Concept: PlantAverageNumberOfEmployees
Employees not specifically assigned to individual units.
(s) Concept: PlantAverageNumberOfEmployees
Employees not specifically assigned to individual units.
(t) Concept: PlantAverageNumberOfEmployees
Employees not specifically assigned to individual units.
(u) Concept: PlantAverageNumberOfEmployees
Employees not specifically assigned to individual units.
(v) Concept: PlantAverageNumberOfEmployees
Unattended-automatic.
(w) Concept: PlantAverageNumberOfEmployees
Unattended-automatic.
(x) Concept: PlantAverageNumberOfEmployees
Unattended-automatic.
(y) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(z) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(aa) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(ab) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(ac) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(ad) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(ae) Concept: AverageCostOfFuelBurnedPerKilowattHourNetGeneration
All fuels.
(af) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
All fuels.
(ag) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
All fuels.
(ah) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
All fuels.
(ai) Concept: AverageBritishThermalUnitPerKilowattHourNetGeneration
All fuels.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Hydroelectric Generating Plant Statistics

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 1894 Plant Name: Parr	FERC Licensed Project No. 2535 Plant Name: Stevens Creek	FERC Licensed Project No. 516 Plant Name: Saluda
1	Kind of Plant (Run-of-River or Storage)		[a] Run-of-River	[b] Run-of-River	[c] Storage
2	Plant Construction type (Conventional or Outdoor)		Conventional	Conventional	Conventional
3	Year Originally Constructed		1914	1914	1930
4	Year Last Unit was Installed		1921	1926	1971
5	Total installed cap (Gen name plate Rating in MW)		14.88	17.28	219.35
6	Net Peak Demand on Plant-Megawatts (60 minutes)		11	20	162
7	Plant Hours Connect to Load		8,740	8,702	7,307
8	**Net Plant Capability (in megawatts)**				
9	(a) Under Most Favorable Oper Conditions		7	17	198
10	(b) Under the Most Adverse Oper Conditions		4	12	198
11	Average Number of Employees		6	3	5
12	Net Generation, Exclusive of Plant Use - kWh		43,626,000	73,266,000	116,719,000
13	**Cost of Plant**				
14	Land and Land Rights		682,243	406,315	6,169,638
15	Structures and Improvements		1,914,616	3,345,938	8,150,293
16	Reservoirs, Dams, and Waterways		6,008,946	15,311,320	354,553,990
17	Equipment Costs		5,926,147	5,671,777	30,674,355
18	Roads, Railroads, and Bridges		124,198	128,812	233,527
19	Asset Retirement Costs				
20	Total cost (total 13 thru 20)		14,656,150	24,864,162	399,781,803
21	Cost per KW of Installed Capacity (line 20 / 5)		984.9563	1,438.8983	1,822.5749
22	**Production Expenses**				
23	Operation Supervision and Engineering		392,153	159,391	289,941
24	Water for Power				

25	Hydraulic Expenses		262,941	87,050	280,330
26	Electric Expenses		158,776	44,056	222,521
27	Misc Hydraulic Power Generation Expenses		16,361	10,800	65,387
28	Rents				
29	Maintenance Supervision and Engineering		462	905	130,708
30	Maintenance of Structures		278,158	25,500	1,919
31	Maintenance of Reservoirs, Dams, and Waterways		166,063	2,960	213,059
32	Maintenance of Electric Plant		116,554	401,126	391,119
33	Maintenance of Misc Hydraulic Plant		155,747	43,755	470,065
34	Total Production Expenses (total 23 thru 33)		1,547,215	775,543	2,065,049
35	Expenses per net kWh		0.0355	0.0106	0.0177

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: PlantKind
Operated under license from the Federal Energy Regulatory Commission.
(b) Concept: PlantKind
Operated under license from the Federal Energy Regulatory Commission.
(c) Concept: PlantKind
Operated under license from the Federal Energy Regulatory Commission.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

Pumped Storage Generating Plant Statistics

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on Line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: 0	FERC Licensed Project No. 1984 Plant Name: Fairfield
1	Type of Plant Construction (Conventional or Outdoor)		Outdoor
2	Year Originally Constructed		1978
3	Year Last Unit was Installed		1978
4	Total installed cap (Gen name plate Rating in MW)		586.8
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	0	570
6	Plant Hours Connect to Load While Generating	0	3,187
7	Net Plant Capability (in megawatts)	0	576
8	Average Number of Employees		22
9	Generation, Exclusive of Plant Use - kWh	0	433,370,000
10	Energy Used for Pumping		603,417,000
11	Net Output for Load (line 9 - line 10) - Kwh	0	(170,047,000)
12	**Cost of Plant**		
13	Land and Land Rights		22,147,163
14	Structures and Improvements	0	38,095,253
15	Reservoirs, Dams, and Waterways	0	74,827,936
16	Water Wheels, Turbines, and Generators	0	68,903,332
17	Accessory Electric Equipment	0	22,447,242
18	Miscellaneous Powerplant Equipment	0	7,138,537
19	Roads, Railroads, and Bridges	0	1,328,336
20	Asset Retirement Costs	0	
21	Total cost (total 13 thru 20)		234,887,799
22	Cost per KW of installed cap (line 21 / 4)		400.2860
23	**Production Expenses**		

24	Operation Supervision and Engineering	0	1,004,130
25	Water for Power	0	
26	Pumped Storage Expenses	0	175,266
27	Electric Expenses	0	1,013,961
28	Misc Pumped Storage Power generation Expenses	0	99,242
29	Rents	0	199
30	Maintenance Supervision and Engineering	0	106,709
31	Maintenance of Structures	0	180,616
32	Maintenance of Reservoirs, Dams, and Waterways	0	304,351
33	Maintenance of Electric Plant	0	1,633,909
34	Maintenance of Misc Pumped Storage Plant	0	358,990
35	Production Exp Before Pumping Exp (24 thru 34)		4,877,373
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)		4,877,373
38	Expenses per kWh (line 37 / 9)		0.0113
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0	0.0047

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 402.
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (MW) (c)	Net Peak Demand MW (60 min) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel Production Expenses (i)	Production Expenses: Maintenance Production Expenses (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Generation Type (m)
1	Hydro-Neal Shoals												
2	Hydro License												
3	Project #2315	1905	4.41	6.0	11,460,000	10,787,716		397,147		83,048			

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 Kw or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWHs delivered/provided to a generator’s own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)	MWHs delivered to the grid to support Production (e)	MWHs delivered to the grid to support Transmission (f)	MWHs delivered to the grid to support Distribution (g)	MWHs Lost During Conversion, Storage and Discharge of Energy Production (h)	MWHs Lost During Conversion, Storage and Discharge of Energy Transmission (i)	MWHs Lost During Conversion, Storage and Discharge of Energy Distribution (j)	MWHs Sold (k)	Revenues from Energy Storage Operations (l)	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1																			
2																			
3																			
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TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage. If required by a State commission to report individual lines for all voltages, do so but do not group totals for each voltage under 132 kilovolts.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
4. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
5. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.
6. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
7. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
8. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
9. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Line No.	DESIGNATION		VOLTAGE (KV) - (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) - (In the case of underground lines report circuit miles)		Number of Circuits	Size of Conductor and Material	COST OF LINE (Include in column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES			
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			Land	Construction Costs	Total Costs	Operation Expenses	Maintenance Expenses	Rents	Total Expenses
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
1	115 KV System	Various	115	230	Various	95.20	15.57	(b) 0	Various 115/230	2,166,432	17,724,586	19,891,018				
2	115 KV System	Various	115	115	Various	1,466.55	101.18	(c) 0	Various 115	76,752,478	527,307,429	604,059,907				
3	46 KV System	Various	46	115	Various	43.77		(d) 0	Various 46/115	442,674	299,245	741,919				
4	46 KV System	Various	46	46	Various	575.30	25.77	(e) 0	Various 46	2,110,292	58,787,839	60,898,131				
5	33 KV System	Various	33	33	Various	63.62	3.29	(f) 0	Various 33	62,375	4,399,104	4,461,479				
6	13.8 KV System	SPA	13.8	46	Various	0.34		1	336mcm 13.8		31,047	31,047				
7	13.8 KV System	Neal Shoals	13.8	14	Wood-SP	11.10		1	336mcm 13.8							
8	13.8 KV System	Neal Shoals	13.8	14	Wood-SP		2.90	2	336mcm 13.8	4,930	638,577	643,507				
9	230 KV System									20,566,555	638,263,906	(g) 658,830,461				
10	Canadys	Faber Place	230	230	Wood-H	38.90		1	795mcm							
11	Canadys	Sumter Cpl Tie	230	230	Wood-H	19.06		1	795mcm							
12	Canadys	Urquhart Jct	230	230	Wood-H	85.04		1	1272mcm							
13	Canadys	Williams	230	230	STEEL-SP	53.49		1	1272mcm							
14	Canadys	Yemassee	230	230	Various	33.96		1	Various							
15	CEC (Cola Energy Ctr)	Fold-In	230	230	STEEL-SP	5.88		1	1272mcm							

16	Church Creek	Faber Place #2	230	230	Wood-H	3.97		1	1272mcm							
17	Church Creek	Yemassee	230	230	Various	52.10		1	1272mcm							
18	Cope	Canadys	230	230	STEEL-SP	40.53		2	795mcm							
19	Cope	Orangeburg	230	230	STEEL-SP	22.05		2	795mcm							
20	Denny Terrace	Lyles #1	230	230	STEEL-SP	2.68		2	1272mcm							
21	Edenwood	Lake Murray	230	230	Wood-H	15.25		1	Various							
22	Edenwood	Lake Murray	230	230	STEEL-SP	0.28		2	Various							
23	Edenwood	Owens Steel	230	230	STEEL-SP	0.41		1	1272mcm							
24	Graniteville	Urquhart Jct	230	230	Wood-H	23.90		1	1272mcm							
25	Graniteville Sub #1	Graniteville Sub #2	230	230	STEEL	0.06		1	1272mcm							
26	Hercules Tap		230	230	Wood-H	0.43		1	1272mcm							
27	Hopkins	Fold-In #1	230	230	STEEL-SP	2.84		1	1272mcm							
28	Hopkins	Fold-In #2	230	230	STEEL-SP	0.48		1	1272mcm							
29	Huron	Tap	230	230	Wood-H	0.11		1	1272mcm							
30	Jasper Co	Yemassee #1	230	230	STEEL-SP	39.49		2	1272mcm							
31	Jasper Co	Yemassee #2	230	230	STEEL-SP	39.27		2	1272mcm							
32	Jasper	Purrysburg (Santee) #1	230	230	STEEL-SP	1.24		1	1272mcm							
33	Jasper	Purrysburg (Santee) #2	230	230	STEEL-SP	1.26		1	1272mcm							
34	Lake Murray	Saluda River #1	230	230	STEEL-SP	6.38		2	1272mcm							
35	Lyles	Saluda River #1	230	230	STEEL-SP	4.13		2	1272mcm							
36	Parr	McMeekin	230	230	Wood-H	38.20		1	795mcm							
37	Pepperhill	Mateeba	230	230	Various	8.78		1	various							
38	Pineland	Denny Terrace	230	230	STEEL-SP	8.28		2	1272mcm							
39	Orangeburg East	St. George	230	230	STEEL-SP	24.04		2	1272mcm							
40	St. George	Williams	230	230	STEEL-SP	43.79		1	various							
41	St. George	Summerville #1	230	230	STEEL-SP	65.97		1	1272mcm							
42	St. George	Summerville #2	230	230	STEEL-SP	65.97		1	1272mcm							
43	SRT	St. George	230	230	Wood-H	67.63		2	1272mcm							
44	Summer	Denny Terrace #1	230	230	Wood-H	52.96		1	various							
45	Summer	Parr #1	230	230	Wood-H	0.06		1	1272mcm							
46	Timberlake	Tap	230	230	Wood-SP	8.41		1	1272mcm							
47	VCS1	Denny Terrace	230	230	Various	16.95		2	1272mcm							
48	VCS1	Fairfield #1	230	230	Wood-H	1.09	0.08	1	1272mcm							
49	VCS1	Fairfield #2	230	230	Wood-H	1.13	0.08	1	1272mcm							
50	VCS1	Killian	230	230	STEEL-SP	3.36		1	1272mcm							

51	VCS1	Killian	230	230	STEEL-SP	38.66		2	1272mcm							
52	VCS1	Newport Tie	230	230	STEEL-SP	10.95		1	various							
53	VCS1	Pineland	230	230	Wood-H	11.53		2	1272mcm							
54	VCS1	Pineland	230	230	STEEL-SP	3.38		1	1272mcm							
55	VCS1	VCS2 Bus Tie #1	230	230	STEEL-SP	2.08		1	1272mcm							
56	VCS2	Bush River Tie	230	230	STEEL-SP	11.17		1	various							
57	VCS2	Denny Terrace	230	230	Various	2.78		1	795mm							
58	VCS2	Graniteville	230	230	Wood-H	63.26		1	1272mcm							
59	VCS2	Lake Murray #1	230	230	STEEL-SP	20.53		2	1272mcm							
60	VCS2	Lake Murray #2	230	230	STEEL-SP	22.74		2	1272mcm							
61	VCS2	Saluda River	230	230	STEEL-SP	27.99		2	1272mcm							
62	VCS2	Orangeburg	230	230	STEEL-SP	71.41		2	1272mcm							
63	Vogtle	SRP	230	230	STEEL-H	17.10		2	1272mcm							
64	Wateree	Denny Terrace	230	230	Wood-H	37.78		1	1272mcm							
65	Wateree	Edenwood	230	230	Wood-H	33.70		1	1272mcm							
66	Wateree	Orangeburg	230	230	Wood-H	27.85		1	795mcm							
67	Wateree	Pineland	230	230	Various	0.23		2	1272mcm							
68	Wateree	Pineland	230	230	Various	7.35		1	1272mcm							
69	Wateree	St. George	230	230	Wood-H	45.85		1	1272mcm							
70	Wateree	Sumter Cpl Tie	230	230	Wood-H	0.86		1	1272mcm							
71	Williams	Cainhoy	230	230	Wood-H	17.52		1	1272mcm							
72	Williams	DuPont #1	230	230	Wood-H	6.60		1	1272mcm							
73	Williams	Faber Place #1	230	230	Wood-H	0.01		1	1272mcm							
74	Williams	Faber Place #1	230	230	STEEL-SP	4.69		2	1272mcm							
75	Williams	Faber Place #2	230	230	Tower-H	13.65	6.71	2	1272mcm							
76	Williams Station ESS	Tie	230	230	Concrete	0.08		1	795mcm							
77	Yemassee	Burton	230	230	STEEL-SP	21.31		2	1272mcm							
78	Yemassee (SCEG)	Yemassee (Santee)	230	230	Wood-H	2.93		2	1272mcm							
79	Underground															
80	33 KV System					0.23		2	250mcm		16,443	16,443				
81	46 KV System					0.90		1	750mcm		1,620,606	1,620,606				
82	115 KV System					19.88		1	2250kcm	10,799,766	75,685,469	86,485,234				
83	[a] See Footnote												[b] 312,939	[c] 6,914,377		7,227,316
36	TOTAL					3,701	156	101		112,905,502	1,324,774,251	1,437,679,752	312,939	6,914,377		7,227,316

FERC FORM NO. 1 (ED. 12-87)

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

Maintenance expense includes Account No. 571 - Maintenance of Overhead Lines and 572 - Maintenance of Underground Lines.

(b) Concept: NumberOfTransmissionCircuits

Various

(c) Concept: NumberOfTransmissionCircuits

Various

(d) Concept: NumberOfTransmissionCircuits

Various

(e) Concept: NumberOfTransmissionCircuits

Various

(f) Concept: NumberOfTransmissionCircuits

Various

(g) Concept: OverallCostOfTransmissionLine

Total capitalized cost of 230kV System.

(h) Concept: OperatingExpensesOfTransmissionLine

Reported costs in column (l) reflect total costs including balances recorded in Account No. 106 - Completed Construction not Classified. Columns (a) through (i) include statistical data related to unitized plant only.

(i) Concept: MaintenanceExpensesOfTransmissionLine

Operation expense includes Account No. 563 - Overhead Line Expenses and 564 - Underground Line Expenses.

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	LINE COST					Construction
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		Land and Land Rights	Poles, Towers and Fixtures	Conductors and Devices	Asset Retire. Costs	Total	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1	Overhead:																
2	Canadys	SRS	0.0023	Steel		1		1272	ACSR	A4SH	230		271,758	12,958		284,716	Overground
3	Canadys	Yemassee	0.0020	Steel		1		1272	ACSR	A4SH	230		226,555	13,727		240,282	Overground
4	Canadys	Faber Place	0.0026	Steel		1		1272	ACSR	A4SH	230		482,709	27,907		510,616	Overground
5	Canadys	Church Creek	0.002	Steel		1		795	ACSR	A4SH	230		151,400	14,110		165,510	Overground
6	Graniteville	Breezy Hill Sub	0.002	Wood	28	1		4/0	ACSR	HLPD	46		70,085	60,687		130,772	
44	TOTAL		0		28	5	0						1,202,507	129,389		1,331,896	

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVA except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation: Transmission or Distribution (b)	Character of Substation: Attended or Unattended (b-1)	VOLTAGE (In MVa): Primary Voltage (In MVa) (c)	VOLTAGE (In MVa): Secondary Voltage (In MVa) (d)	VOLTAGE (In MVa): Tertiary Voltage (In MVa) (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	Conversion Apparatus and Special Equipment: Type of Equipment (i)	Conversion Apparatus and Special Equipment: Number of Units (j)	Conversion Apparatus and Special Equipment: Total Capacity (In MVa) (k)
1	Aiken, Aiken County	Transmission	Unattended	115.00	46.00		28	1				
2	Aiken, Aiken County	Transmission	Unattended	115.00	12.00		22	1				
3	Barnwell, Barnwell County	Transmission	Unattended	115.00	46.00		56	2				
4	Batesburg, City of Batesburg	Transmission	Unattended	115.00	33.00		28	1				
5	Batesburg, City of Batesburg	Transmission	Unattended	115.00	23.00		28	1				
6	Bayview, Mt. Pleasant City	Transmission	Unattended	115.00	23.00		75	2				
7	Blackville 115-46KV, Barnwell County	Transmission	Unattended	115.00	46.00		28	1				
8	Blackville 115-46KV, Barnwell County	Transmission	Unattended	115.00	12.00		28	1				
9	Burton Transmission, Beaufort County	Transmission	Unattended	230.00	115.00		224	1				
10	Burton Transmission, Beaufort County	Transmission	Unattended	115.00	46.00		112	2	4			
11	Cainhoy 230-115kV, Berkeley County	Transmission	Unattended	230.00	115.00		336	1				
12	Cainhoy 230-115kV, Berkeley County	Transmission	Unattended	115.00	23.00		56	2				
13	Calhoun County, Calhoun County	Transmission	Unattended	115.00	46.00		28	1				
14	Calhoun Falls, Calhoun Falls City	Transmission	Unattended	115.00	46.00		50	2				
15	Calhoun Falls, Calhoun Falls City	Transmission	Unattended	46.00	12.00		7	1	1			
16	Canadys Sub, Colleton County	Transmission	Unattended	230.00	115.00		224	1	1			
17	Charleston, Charleston County	Transmission	Unattended	115.00	23.00		67	2				
18	Church Creek, Charleston County	Transmission	Unattended	230.00	115.00		896	3				
19	Coit Gas Turbine, Richland County	Transmission	Unattended	13.80	33.00		56	2				
20	Coit, Richland County	Transmission	Unattended	115.00	23.00		22	1				
21	Coit, Richland County	Transmission	Unattended	115.00	33.00		56	1				

22	Columbia Energy, Calhoun County	Transmission	Unattended	18.00	115.00		250	1				
23	Columbia Energy, Calhoun County	Transmission	Unattended	18.00	230.00		583	2				
24	Columbia Industrial Park, Richland County	Transmission	Unattended	230.00	115.00		336	1				
25	Cope, Orangeburg County	Transmission	Unattended	230.00	115.00		224	1				
26	Cope, Orangeburg County	Transmission	Unattended	23.00	230.00		549	1				
27	Denmark, City of Denmark	Transmission	Unattended	115.00	46.00		56	2				
28	Denny Terrace, Richland County	Transmission	Unattended	230.00	115.00		672	2				
29	Edenwood, City of Cayce	Transmission	Unattended	230.00	115.00		448	2				
30	Faber Place, City of North Charleston	Transmission	Unattended	115.00	23.00		73	3				
31	Faber Place, City of North Charleston	Transmission	Unattended	230.00	115.00		672	2	1			
32	Fairfax, Allendale County	Transmission	Unattended	115.00	46.00		56	2				
33	Fairfield Pumped Storage, Fairfield County	Transmission	Unattended	13.80	230.00		717	4	1			
34	Goose Creek, Hanahan City	Transmission	Unattended	230.00	115.00		336	1				
35	Graniteville #1, Aiken County	Transmission	Unattended	115.00	46.00		56	2				
36	Graniteville #1, Aiken County	Transmission	Unattended	230.00	115.00		448	2				
37	Graniteville #2, Aiken County	Transmission	Unattended	230.00	115.00		336	1				
38	Hagood Gas Turbine, Charleston County	Transmission	Unattended	13.80	115.00		60	1				
39	Hagood Gas Turbine, Charleston County	Transmission	Unattended	13.20	115.00		147	1				
40	Hagood Gas Turbine, Charleston County	Transmission	Unattended	13.80	4.16		6	1				
41	Hamlin, Charleston County	Transmission	Unattended	115.00	23.00		112	3	1			
42	Hampton, Hampton County	Transmission	Unattended	115.00	46.00		84	3	2			
43	Hanahan, Hanahan City	Transmission	Unattended	115.00	23.00		78	3				
44	Hanahan, Hanahan City	Transmission	Unattended	115.00	46.00		56	2				
45	Hardeeville, Jasper County	Transmission	Unattended	115.00	46.00		28	1				
46	Hobcaw, Charleston County	Transmission	Unattended	115.00	24.94		28	1				
47	Hopkins, Richland County	Transmission	Unattended	230.00	115.00		672	2				
48	Jasper 230kV, Jasper County	Transmission	Unattended	18.00	230.00		700	3				
49	Jasper 230kV, Jasper County	Transmission	Unattended	21.00	230.00		500	1				
50	Kendrick, Richland County	Transmission	Unattended	115.00	23.00		84	3	1			
51	Killian, Richland County	Transmission	Unattended	230.00	115.00		336	1				
52	Lake Murray, Lexington County	Transmission	Unattended	230.00	115.00		672	2	1			
53	Lyles, Richland County	Transmission	Unattended	230.00	115.00		336	1	1			
54	Lyles, Richland County	Transmission	Unattended	115.00	23.00		56	2				
55	Lyles, Richland County	Transmission	Unattended	115.00	35.00		56	1	1			
56	McCormick, McCormick County	Transmission	Unattended	115.00	46.00		58	2	1			

57	McMeekin, Lexington County	Transmission	Unattended	13.20	115.00		350	2				
58	Orangeburg #1, Orangeburg County	Transmission	Unattended	115.00	46.00		81	3	1			
59	Orangeburg East 230KV, Orangeburg County	Transmission	Unattended	230.00	115.00		672	2				
60	Parr Gas Turbine, Fairfield County	Transmission	Unattended	13.20	115.00		98	2	1			
61	Parr Hydro, Fairfield County	Transmission	Unattended	2.30	13.80		25	3				
62	Parr Steam, Fairfield County	Transmission	Unattended	115.00	13.20		34	1				
63	Pepperhill, Charleston County	Transmission	Unattended	230.00	115.00		336	1				
64	Pineland, Richland County	Transmission	Unattended	230.00	115.00		672	2				
65	Rader, Richland County	Transmission	Unattended	115.00	23.00		45	2				
66	Ridgeville, City of Ridgeville	Transmission	Unattended	115.00	46.00		28	1				
67	Ridgeville, City of Ridgeville	Transmission	Unattended	115.00	23.00		28	1				
68	Ritter, Colleton County	Transmission	Unattended	230.00	115.00		336	1				
69	Saluda Hydro, Lexington County	Transmission	Unattended	13.20	115.00		275	5				
70	Saluda Hydro, Lexington County	Transmission	Unattended	115.00	23.00		66	2				
71	Saluda River, Lexington County	Transmission	Unattended	230.00	115.00		336	1				
72	Santee, Orangeburg County	Transmission	Unattended	230.00	46.00		28	1				
73	Santee, Orangeburg County	Transmission	Unattended	115.00	46.00		28	1				
74	Santee, Orangeburg County	Transmission	Unattended	230.00	115.00		140	1				
75	Savannah River, Federal Property	Transmission	Unattended	230.00	115.00		672	2				
76	St. Andrews, Charleston City	Transmission	Unattended	115.00	23.00		22	1				
77	St. George, Dorchester County	Transmission	Unattended	115.00	46.00		28	1				
78	Stevens Creek Hydro, Columbia Cnty Ga.	Transmission	Unattended	2.40	46.00		28	4				
79	Stevens Creek Sub, Columbia Cnty Ga.	Transmission	Unattended	115.00	46.00		28	1	1			
80	Summerville, Berkeley County	Transmission	Unattended	230.00	115.00		672	2				
81	Thomas Island, Charleston County	Transmission	Unattended	115.00	23.00		75	2				
82	Trenton, Edgefield County	Transmission	Unattended	115.00	23.00		37	1	1			
83	Trenton, Edgefield County	Transmission	Unattended	115.00	46.00		56	2				
84	Urquhart 115KV, Aiken County	Transmission	Unattended	115.00	13.20		325	6				
85	Urquhart 115-46KV, Aiken County	Transmission	Unattended	115.00	46.00		48	2				
86	Urquhart 230KV, Aiken County	Transmission	Unattended	18.00	230.00		467	2	1			
87	Urquhart Gas Turbine, Aiken County	Transmission	Unattended	13.20	115.00		176	3	1			
88	V. C. Summer Substation, Fairfield County	Transmission	Unattended	22.00	230.00		1232	1	1			
89	Ward, Saluda County	Transmission	Unattended	230.00	115.00		364	2	1			
90	Ward, Saluda County	Transmission	Unattended	115.00	23.00		22	1				
91	Ward, Saluda County	Transmission	Unattended	115.00	33.00		28	1				

92	Wateree Plant, Richland County	Transmission	Unattended	21.00	230.00		1008	2	1			
93	Wateree Plant, Richland County	Transmission	Unattended	230.00	13.80		75	2				
94	Williams Gas Turbine, Berkeley County	Transmission	Unattended	13.20	115.00		70	1				
95	Williams St., Columbia City	Transmission	Unattended	115.00	23.00		60	2				
96	Williams Station, Berkeley County	Transmission	Unattended	20.00	230.00		785	1	1			
97	Williams Station, Berkeley County	Transmission	Unattended	115.00	230.00		560	2				
98	Williams Station, Berkeley County	Transmission	Unattended	230.00	4.16		93	2				
99	Williams Station, Berkeley County	Transmission	Unattended	230.00	23.00		101	2				
100	Williston Industrial Park , Barnwell County	Transmission	Unattended	115.00	46.00		32	6				
101	Yemassee, City of Yemassee	Transmission	Unattended	230.00	115.00		784	3				
102	Blackville West, Barnwell County	Transmission	Unattended	115.00	46.00		56	1				
103	Distribution Substations:											
104	Adams Run, Charleston County	Distribution	Unattended	115.00	23.00		50	2				
105	Adams Run, Charleston County	Distribution	Unattended	115.00	46.00		112	2				
106	Aiken #2, Aiken County	Distribution	Unattended	115.00	12.00		51	2				
107	Aiken #3, Aiken County	Distribution	Unattended	115.00	12.00		51	2				
108	Aiken Hampton Avenue, Aiken City	Distribution	Unattended	115.00	12.00		28	1				
109	Aiken Industrial Park, Aiken City	Distribution	Unattended	46.00	23.00		11	1				
110	Aiken-Steifeltown, Aiken County	Distribution	Unattended	115.00	12.00		22	1				
111	Allendale, Allendale City	Distribution	Unattended	115.00	12.00		22	1				
112	Arrowwood Road, Richland County	Distribution	Unattended	115.00	23.00		22	1				
113	Ashley Phosphate, City of North Charleston	Distribution	Unattended	115.00	23.00		60	2				
114	Bacon's Bridge, Summerville City	Distribution	Unattended	115.00	23.00		37	1				
115	Baldock, Allendale County	Distribution	Unattended	115.00	12.00		22	1				
116	Bamberg Central, Bamberg City	Distribution	Unattended	43.80	12.00		14	2				
117	Barnwell City, Barnwell City	Distribution	Unattended	46.00	12.00		11	1				
118	Barnwell Heights, Barnwell City	Distribution	Unattended	46.00	12.00		11	1				
119	Barnwell Industrial Park, Barnwell County	Distribution	Unattended	43.80	12.00		11	1				
120	Batesburg City, Lexington County	Distribution	Unattended	33.00	8.00		11	1				
121	Bayfront, Charleston City	Distribution	Unattended	115.00	23.00		40	1				
122	Beaufort Central, Beaufort City	Distribution	Unattended	115.00	12.00		28	1				
123	Beaufort Industrial Park, Beaufort County	Distribution	Unattended	115.00	12.00		22	1				
124	Bee Street, Charleston County	Distribution	Unattended	115.00	14.40		202	4				
125	Beech Island, Aiken County	Distribution	Unattended	46.00	12.00		11	1				
126	Bellwright, Berkeley County	Distribution	Unattended	115.00	23.00		28	1				

127	Belmont, Richland County	Distribution	Unattended	115.00	23.00		50	2				
128	Belvedere, North Augusta City	Distribution	Unattended	115.00	12.00		50	2				
129	Blackville 46-12KV, Barnwell County	Distribution	Unattended	46.00	12.00		11	1				
130	Bluffton, Beaufort County	Distribution	Unattended	115.00	23.00		56	2				
131	Blythewood, Richland County	Distribution	Unattended	115.00	23.00		75	2				
132	Boney Rd. , Fairfield County	Distribution	Unattended	115.00	23.00		45	2				
133	Boone Hill, Dorchester County	Distribution	Unattended	115.00	23.00		60	2				
134	Bowman, Orangeburg County	Distribution	Unattended	115.00	8.00		11	1				
135	Brookwood, West Columbia City	Distribution	Unattended	115.00	23.00		28	1				
136	Burton Central, Beaufort County	Distribution	Unattended	115.00	12.00		56	2				
137	CAE Industrial Park, Lexington County	Distribution	Unattended	115.00	23.00		28	1				
138	Cainhoy, Berkeley County	Distribution	Unattended	115.00	23.00		28	1				
139	Calhoun Street, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
140	Callawassie Island, Jasper County	Distribution	Unattended	115.00	23.00		28	1	1			
141	Carlisle, Carlisle City	Distribution	Unattended	115.00	23.00		21	4				
142	Carolina Bay, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
143	Cayce, City of Cayce	Distribution	Unattended	33.00	8.00		13	2				
144	Center Sub, Aiken County	Distribution	Unattended	46.00	23.00		11	1				
145	Chapin Business Park, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
146	Charleston Airport, N Charleston City	Distribution	Unattended	115.00	23.00		40	1				
147	Charlotte Street, Charleston City	Distribution	Unattended	115.00	14.40		101	4				
148	Church Creek 115-23kV, Charleston City	Distribution	Unattended	115.00	23.00		75	2				
149	Circle Drive, Richland County	Distribution	Unattended	115.00	8.00		22	1				
150	Clearwater, Aiken County	Distribution	Unattended	115.00	12.00		28	1				
151	Cloverleaf, Aiken County	Distribution	Unattended	115.00	12.00		22	1	1			
152	Colonial Heights, Richland County	Distribution	Unattended	115.00	23.00		22	1				
153	Columbia Airport, Springdale City	Distribution	Unattended	115.00	23.00		22	1				
154	Columbia Industrial Park, Richland County	Distribution	Unattended	115.00	23.00		37	1				
155	Congaree Creek, Cayce City	Distribution	Unattended	115.00	23.00		28	1				
156	Congaree Vista South, Richland County	Distribution	Unattended	115.00	23.00		37	1				
157	Cooper River, Berkeley County	Distribution	Unattended	115.00	23.00		28	1				
158	Coosaw, Charleston County	Distribution	Unattended	115.00	23.00		37	1				
159	Cromer Rd, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
160	Deer Park, Charleston County	Distribution	Unattended	115.00	23.00		45	2				
161	Denmark Industrial Park, Denmark City	Distribution	Unattended	46.00	12.00		11	1	1			

162	Dentsville, Richland County	Distribution	Unattended	115.00	23.00		45	2				
163	Dixiana, Lexington County	Distribution	Unattended	115.00	23.00		65	2				
164	East Columbia, Richland County	Distribution	Unattended	115.00	23.00		37	1				
165	Edmund, Lexington County	Distribution	Unattended	115.00	23.00		22	1				
166	Estill, Estill City	Distribution	Unattended	46.00	12.00		14	1				
167	Estill Southside, Estill City	Distribution	Unattended	46.00	12.00		25	2	1			
168	Eutawville, Orangeburg County	Distribution	Unattended	115.00	23.00		50	2				
169	Fairfax Central, Fairfax City	Distribution	Unattended	46.00	12.00		18	2				
170	Five Points, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
171	Fort Johnston Road, Charleston County	Distribution	Unattended	115.00	23.00		50	2				
172	Frogmore, Beaufort County	Distribution	Unattended	115.00	23.00		28	1				
173	Gardens Corner, Beaufort County	Distribution	Unattended	115.00	23.00		22	1				
174	Gaston, Lexington County	Distribution	Unattended	115.00	23.00		50	2				
175	Gilbert, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
176	Gills Creek, Richland County	Distribution	Unattended	115.00	23.00		37	1				
177	Grays Hill, Beaufort County	Distribution	Unattended	115.00	12.00		22	1				
178	Greengate, Richland County	Distribution	Unattended	115.00	23.00		37	1				
179	Grove Street, Charleston City	Distribution	Unattended	115.00	14.40		22	1				
180	Hampton City, Hampton County	Distribution	Unattended	46.00	12.00		21	2				
181	Hanahan Switching, Berkeley County	Distribution	Unattended	46.00	4.16		14	2	1			
182	Harbison, Lexington County	Distribution	Unattended	115.00	23.00		50	2				
183	Hardeeville, Hardeeville City	Distribution	Unattended	115.00	23.00		28	1	1			
184	Herrin, Allendale County	Distribution	Unattended	46.00	12.00		11	1				
185	Holly Hill, Holly Hill City	Distribution	Unattended	115.00	23.00		50	4	1			
186	Houndslake, Aiken County	Distribution	Unattended	115.00	12.00		28	1				
187	Howard Street, Richland County	Distribution	Unattended	33.00	8.00		11	1				
188	Irmo Town, Irmo City	Distribution	Unattended	115.00	23.00		56	2				
189	Isle of Palms, Isle of Palms City	Distribution	Unattended	115.00	23.00		50	2				
190	Jack Primus, Berkeley County	Distribution	Unattended	115.00	23.00		37	1				
191	Jackson 46-12kV, Aiken County	Distribution	Unattended	46.00	12.00		11	1				
192	Jackson Street, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
193	James Island, Charleston County	Distribution	Unattended	115.00	23.00		45	2				
194	James Prioleau, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
195	Jasper 115kV Construction, Jasper County	Distribution	Unattended	115.00	23.00		11	1				
196	Johnston 115-23KV, Edgefield County	Distribution	Unattended	115.00	23.00		22	1				

197	Kilbourne Park, Richland County	Distribution	Unattended	115.00	23.00		60	2				
198	Killian, Richland County	Distribution	Unattended	115.00	23.00		37	1				
199	Kingswood, Richland County	Distribution	Unattended	115.00	23.00		50	2				
200	Ladies Island, Beaufort County	Distribution	Unattended	115.00	23.00		50	2				
201	Lake Carolina, Richland County	Distribution	Unattended	115.00	23.00		65	2				
202	Lake Murray Training, Lexington County	Distribution	Unattended	115.00	23.00		22	1				
203	Langley, Aiken County	Distribution	Unattended	115.00	12.00		22	1				
204	Laurel Bay 115-12KV, Beaufort County	Distribution	Unattended	115.00	12.00		28	1				
205	Leesville 115-23KV, Lexington County	Distribution	Unattended	115.00	23.00		28	1				
206	Lexington 115-23kV, Lexington County	Distribution	Unattended	115.00	23.00		65	2	1			
207	Lexington East Side, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
208	Lexington Industrial Park, Lexington County	Distribution	Unattended	115.00	23.00		75	2	1			
209	Lexington West Side, Lexington County	Distribution	Unattended	115.00	23.00		75	2				
210	Lower Richland, Richland County	Distribution	Unattended	115.00	23.00		60	2				
211	Maryville, Charleston County	Distribution	Unattended	115.00	23.00		37	1				
212	McCormick City 115-12KV, McCormick Cnty	Distribution	Unattended	115.00	12.00		11	1	1			
213	Meadowbrook, Beaufort County	Distribution	Unattended	115.00	23.00		22	1				
214	Meeting Street, Charleston County	Distribution	Unattended	115.00	14.40		28	1				
215	Middleburg Mall, Richland County	Distribution	Unattended	115.00	8.00		22	1				
216	Midway, Union County	Distribution	Unattended	115.00	13.80		20	1	2			
217	Midway, Union County ground bank	Distribution	Unattended	13.80	4.80		1	3				
218	Midway, Union County	Distribution	Unattended	115.00	23.00		1	22				
219	Mt Pleasant, Charleston County	Distribution	Unattended	115.00	23.00		77	2				
220	Muller Avenue, Richland County	Distribution	Unattended	115.00	8.00		22	1				
221	Muller Avenue, Richland County	Distribution	Unattended	115.00	23.00		28	1				
222	Navy Yard 115-23kV, Federal Property, SC	Distribution	Unattended	115.00	23.00		28	1				
223	Navy Yard 115-23kV, Federal Property, SC	Distribution	Unattended	115.00	13.80		22	1				
224	Neeses, Orangeburg County	Distribution	Unattended	46.00	8.00		11	1				
225	Network, Richland County	Distribution	Unattended	115.00	13.80		67	3				
226	North 46-8kV, Orangeburg County	Distribution	Unattended	46.00	8.00		11	1				
227	North Augusta, Aiken City	Distribution	Unattended	115.00	12.00		28	1				
228	North Bridge Terrace, Charleston County	Distribution	Unattended	115.00	23.00		45	2				
229	North Naval Weapons, Federal Property	Distribution	Unattended	115.00	13.80		22	1				
230	North Rhett, North Charleston City	Distribution	Unattended	115.00	23.00		28	1				
231	Northpointe Business Park, Charleston County	Distribution	Unattended	115.00	23.00		37	1				

232	Northwoods Mall, North Charleston City	Distribution	Unattended	230.00	23.00		75	2	1			
233	Okatie, Jasper County	Distribution	Unattended	115.00	23.00		28	1				
234	Old Fort, Dorchester County	Distribution	Unattended	115.00	23.00		60	2				
235	Osceola Park, Charleston County	Distribution	Unattended	115.00	23.00		75	2				
236	Palmetto Commerce Park, Charleston City	Distribution	Unattended	115.00	23.00		65	2				
237	Park Street, Columbia City	Distribution	Unattended	115.00	13.80	0	56	2	0			
238	Parr Hill 115-23kV, Fairfield County	Distribution	Unattended	115.00	23.00		22	1				
239	Pelion, Lexington County	Distribution	Unattended	115.00	23.00		45	2				
240	Pendleton Street, Columbia City	Distribution	Unattended	115.00	8.00		45	2				
241	Pine Hill 230-23kV, Dorchester County	Distribution	Unattended	230.00	23.00		37	1				
242	Piney Woods Road, Richland County	Distribution	Unattended	115.00	23.00		37	1				
243	Platt Springs Rd., Lexington County	Distribution	Unattended	115.00	23.00		51	2				
244	Pontiac, Richland County	Distribution	Unattended	230.00	23.00		75	2				
245	Port Park, Hanahan City	Distribution	Unattended	115.00	23.00		22	1				
246	Port Royal, Port Royal City	Distribution	Unattended	115.00	12.00		28	1				
247	Pritchardville, Beaufort County	Distribution	Unattended	115.00	23.00		37	1				
248	Quail Hollow, Lexington County	Distribution	Unattended	115.00	23.00		37	1	2			
249	Raborn Pointe, North Augusta City	Distribution	Unattended	115.00	12.00		22	1				
250	Rantowles, Charleston County	Distribution	Unattended	115.00	23.00		28	1				
251	Red Bank 115-23kV, Lexington County	Distribution	Unattended	115.00	23.00		37	1				
252	Red House Rd, Charleston County	Distribution	Unattended	46.00	23.00		45	2	1			
253	Richland Mall, Forest Acres City	Distribution	Unattended	115.00	8.00		45	2				
254	Ridgeland, Jasper County	Distribution	Unattended	115.00	23.00		22	1	1			
255	Riverland Terrace, Charleston County	Distribution	Unattended	115.00	23.00		22	1				
256	Riverland Terrace, Charleston County	Distribution	Unattended	23.00	4.16		4	1				
257	Rosewood, Columbia City	Distribution	Unattended	33.00	8.00		21	2				
258	Sage Mill Ind Park, Aiken County	Distribution	Unattended	115.00	12.00		28	1				
259	Saluda County, Saluda County	Distribution	Unattended	115.00	23.00		23	1				
260	Sandhill, Richland County	Distribution	Unattended	115.00	23.00		75	2				
261	Santee 46-8kV, Orangeburg County	Distribution	Unattended	46.00	8.00		21	2				
262	Savage Road, Charleston County	Distribution	Unattended	115.00	23.00		67	3				
263	Saxe Gotha Industrial Park, Lexington County	Distribution	Unattended	115.00	23.00		74	2				
264	SC Research Association, Richland County	Distribution	Unattended	115.00	23.00		50	2				
265	Seven Mile, North Charleston City	Distribution	Unattended	115.00	23.00		23	1				
266	Sewee 115-23KV, Charleston County	Distribution	Unattended	115.00	23.00		28	1				

267	Shell Point, Beaufort County	Distribution	Unattended	46.00	12.00		28	2	1			
268	Silver Bluff Rd, Aiken County	Distribution	Unattended	115.00	12.00		23	1				
269	South Main, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
270	South Main, Columbia City	Distribution	Unattended	115.00	23.00		37	1				
271	Sparkleberry, Richland County	Distribution	Unattended	115.00	23.00	23	38	1				
272	Sparkleberry, Richland County	Distribution	Unattended	115.00	23.00		37	1				
273	Springdale, Lexington County	Distribution	Unattended	115.00	23.00		45	2	1			
274	St. George 115-12kV, Dorchester County	Distribution	Unattended	115.00	12.00		28	1				
275	St. Helena Island, Beaufort County	Distribution	Unattended	115.00	23.00		51	2				
276	St. Matthews 46-23kV, Calhoun County	Distribution	Unattended	46.00	23.00	23	23	2	1			
277	Stono Park, Charleston City	Distribution	Unattended	115.00	23.00		37	1				
278	Summer Construction, Fairfield County	Distribution	Unattended	115.00	23.00		23	1				
279	Summerville Central, Berkeley County	Distribution	Unattended	115.00	23.00		40	1				
280	Summerville Industrial Park, Dorchester County	Distribution	Unattended	115.00	23.00		50	2				
281	Summerville Plaza, City of Summerville	Distribution	Unattended	115.00	23.00		37	1				
282	Summerville-Ladson, Charleston County	Distribution	Unattended	115.00	23.00		65	2				
283	Swansea, Lexington County	Distribution	Unattended	46.00	23.00		11	1				
284	Sweetwater, Aiken County	Distribution	Unattended	115.00	12.00		56	2				
285	Ten Mile, Charleston County	Distribution	Unattended	115.00	23.00		22	1				
286	Timberlake, Lexington County	Distribution	Unattended	230.00	23.00		37	1	1			
287	Uptown, Columbia City	Distribution	Unattended	115.00	23.00		37	1	1			
288	Uptown, Columbia City	Distribution	Unattended	115.00	8.00		23	1				
289	Varnville, Varnville City	Distribution	Unattended	46.00	12.00		11	1				
290	Victory Gardens, Columbia City	Distribution	Unattended	115.00	8.00		22	1				
291	Wagener, Wagnener City	Distribution	Unattended	46.00	8.00		11	1				
292	Walterboro 115-23KV, Walterboro City	Distribution	Unattended	115.00	23.00		22	1				
293	Walterboro Forest Hill, Walterboro City	Distribution	Unattended	115.00	23.00		40	1				
294	Walterboro Ind Park, Walterboro City	Distribution	Unattended	115.00	23.00		28	1				
295	Walterboro South Side, Walterboro City	Distribution	Unattended	115.00	23.00		22	1				
296	West Columbia, West Columbia City	Distribution	Unattended	33.00	8.00		18	2				
297	White Gables, Dorchester County	Distribution	Unattended	115.00	23.00		37	1				
298	White Rock, Richland County	Distribution	Unattended	115.00	23.00		50	2	1			
299	Whitehall, Lexington County	Distribution	Unattended	115.00	23.00		22	1				
300	Williston, Williston City	Distribution	Unattended	115.00	12.00		22	1				
301	Winnsboro, Winnsboro City	Distribution	Unattended	115.00	23.00		45	2				

302	Woodfield Park, Richland County	Distribution	Unattended	115.00	23.00		45	2				
303	Yemassee Central, Yemassee City	Distribution	Unattended	115.00	23.00		22	1				
304	Calhoun Street, Columbia City	Distribution	Unattended	115.00	23.00		37	1				
305	Garners Ferry, Richland County	Distribution	Unattended	115.00	23.00		28	1				
306	Smoaks - Collenton County	Distribution	Unattended	46.00	13.80		6	1				
307	Smoaks - Collenton County	Distribution	Unattended	115.00	23.00		28	1				
308	May River - Beaufort County	Distribution	Unattended	115.00	23.00		37	1				
309	Cope Dist - Orangeburg County	Distribution	Unattended	115.00	23.00		28	1				
310	Ulmer - Allendale County	Distribution	Unattended	46.00	12.00		7	1				
311	Under 10,000 KVA (35)	Distribution	Unattended				186					
312	TotalDistributionSubstationMember						7,441	312	23			0
313	TotalTransmissionSubstationMember						23,790	183	26			0
314	Total						31,231	495	49			0

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	[(a)] Charges for Costs and Services	Dominion Energy Services, Inc.		221,577,523
3	[(b)] Coal and transportation services received	South Carolina Generating Company, Inc.	151	220,188
19				
20	**Non-power Goods or Services Provided for Affiliated**			
21	Shared resources (labor, related travel expenses, other business expenses and outside services) related to storm restoration in Virginia	Dominion Energy Nuclear Connecticut - Millstone	[(d)] See Footnote	638,578
22	Rental Fee for Use of Assets	Dominion Energy Services, Inc.	454/493	3,692,510
23	[(c)] Coal and transportation services provided	South Carolina Generating Company, Inc.	151	1,146,198
42				

Name of Respondent: Dominion Energy South Carolina, Inc.	This report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report: 03/24/2023	Year/Period of Report End of: 2022/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfNonPowerGoodOrService

The transactions below represent costs and services billed by Dominion Energy Services, Inc. to the Company during the reporting period.

FERC Account	Description	Charges
143	Other Accounts Receivable	$ 113,798
174	Miscellaneous Current and Accrued Assets	14,387
182.2	Unrecovered Plant & Regulatory Study Costs	6,215
182.3	Other Regulatory Assets	356,996
183	Other Preliminary Survey and Investigation Charges	224,327
107	Construction Work in Progress	10,077,440
186	Miscellaneous Deferred Debits	212,273
408.1	Taxes Other than Income Taxes - Utility Operating Income	7,331,806
408.2	Taxes Other than Income Taxes - Other Income and Deductions	64,686
416	Costs & Expenses of Merchandising, Jobbing & Contractor Work	283,058
421	Miscellaneous Nonoperating Income	(198,558)
421.2	Loss on Disposition of Property	1,415
426.1	Donations	508,443
426.2	Life Insurance	9,534
426.3	Penalties	696
426.4	Expenditures for Certain Civic, Political & Related Activities	2,640,266
426.5	Other Deductions	2,906,736
431	Other Interest Expense	309,650
501	Steam Operation - Fuel	193,871
506	Steam Operation - Miscellaneous Steam Power Expenses	42,785
524	Nuclear Operation - Miscellaneous Nuclear Power Expenses	3,986,054
549	Other Power Operations - Miscellaneous Other Power Generation Expenses	(738,701)
553	Other Power Maintenance - Generating & Electric Equipment	296
556	Other Power Supply - System Control & Load Dispatching	9,543
571	Transmission Maintenance - Overhead Lines	44,669
588	Distribution Operation - Miscellaneous Expenses	999,384
840	Other Storage Operation - Supervision & Engineering	83,347
856	Gas Transmission Maintenance - Mains Expenses	352
861	Gas Transmission Maintenance - Supervision & Engineering	631,434
874	Gas Distribution Operations - Mains and Services Expenses	771,182
879	Gas Distribution Operations - Customer Installations Expenses	299,199
880	Gas Distribution Operations - Other Expenses	2,315,387
887	Gas Distribution Maintenance - Mains	203,915

893	Gas Distribution Maintenance - Meters and House Regulators	510,838
901	Customer Accounts - Supervision	26,051
903	Customer Accounts - Customer Records & Collections Expenses	20,536,810
905	Customer Accounts - Miscellaneous Expenses	4,725,168
908	Customer Assistance Expenses	915,666
912	Sales Expense - Demonstrating & Selling Expenses	9,543
913	Advertising Expense	2,260
920	Administrative & General Operation - Salaries	81,084,848
921	Administrative & General Operation - Office Supplies & Expenses	24,367,104
923	Administrative & General Operation - Outside Services Employed	13,048,072
925	Administrative & General Operation - Injuries & Damages	12,121
926	Administrative & General Operation - Employee Pensions & Benefits	13,254,537
928	Administrative & General Operation - Regulatory Commission Expenses	399,244
930.1	Administrative & General Operation - General Advertising Expenses	703,155
930.2	Administrative & General Operation - Miscellaneous General Expenses	4,483,979
931	Administrative & General Operation - Rents	11,236,895
932	Administrative & General Maintenance -Maintenance of General Plant	1,615,080
935	Administrative & General Maintenance - Maintenance of General Plant	10,940,267
	TOTAL	**$ 221,577,523**

Departmental Services and Expense	Charges	Allocation Method
Capital / Assets	$ 11,005,436	
Accounting Services	7,321,888	(A) Headcount, (B) Accounts Payable Processing, (C) Fixed Assets, (N) Accounts Payable P-Card
Auditing	1,314,908	(Q) O&M
Business Services	16,151,224	(I) Square Footage, (J) Fleet, (A) Headcount, (Q) O&M, (R) Aviation
Corporate Planning	11,415,845	(M) Capitalization
Corporate Secretary	103,624	(Q) O&M
Customer Service	28,757,245	(P) Customer Payments
Environmental Compliance	4,036,086	(Q) O&M
Energy Marketing	564,992	(Q) O&M
Executive and Administration	13,938,286	(Q) O&M
External Affairs	11,648,395	(Q) O&M
Human Resources	6,781,872	(A) Headcount
Information Technology, Electronic Transmission & Computer Services	50,905,357	(D) Number of Customers, (F) Number of Users (EID's), (G) Other Computer Applications, (H) Telecom
Interest Expense	392,201	(E) Affiliate Billings
Legal and Regulatory	5,571,184	(Q) O&M
Office Space	3,195,894	(K) Headcount Corporate Offices
Operations	25,422,848	(Q) O&M, (T) Gas Volumes
Other	85,446	(Q) O&M
Rates and Regulatory	2,495,211	(Q) O&M
Risk Management	550,531	(L) Insurance Premiums
Software/ Hardware Pooling	10,145,652	(F) Number of Users (EID's)
Supply Chain	6,192,506	(S) Purchases
Tax	1,148,066	(O) Taxes
Treasury / Finance	2,432,826	(M) Capitalization
TOTAL	**$ 221,577,523**	

Legend		Allocation Methodology
(A)	Headcount	Number of Dominion Company employees as of the preceding December 31st.
(B)	Accounts Payable Processing	Number of Dominion Company accounts payable documents processed during the preceding year ended December 31st.
(C)	Fixed Assets	Dominion Company fixed assets added, retired or transferred during the preceding year ended December 31st.
(D)	Number of Customers	Number of Dominion Company customers at the end of the preceding year ended December 31st.
(E)	Affiliate Billings	Portion of direct and allocated costs.
(F)	Number of Users (EID's)	Number of Dominion Company Employee users at the end of the preceding year ended December 31st.
(G)	Other Computer Applications	Number of Dominion Company usage of specific computer systems at the end of the preceding year ended December 31st.
(H)	Telecom	Number of Dominion Company telecommunications units at the end of the preceding year ended December 31st.
(I)	Square Footage	Square footage of Dominion Company office space as of the preceding year ended December 31st.
(J)	Fleet	Number of Dominion Company vehicles as of the preceding December 31st.
(K)	Headcount Corporate Offices	Headcount at corporate offices as of the previous December 31st.
(L)	Insurance Premiums	Dominion Company insurance premiums for the preceding year ended December 31st.
(M)	Capitalization	Total Dominion Company capitalization (Debt and Equity) recorded at preceding December 31st.
(N)	Accounts Payable P-Card	Dollar value of Dominion Company purchases on company credit cards for the preceding year ended December 31st.
(O)	Taxes	The sum of the total income and total deductions as reported for Dominion Consolidated Federal Income Tax purposes on the last return filed.
(P)	Customer Payments	Number of Dominion Company customer payments processed during the preceding year ended December 31st.
(Q)	O&M	Total operating expenses, excluding purchased gas expense, purchased power expense (including fuel expense), other purchased products and royalties, depreciation, depletion, and amortization, and taxes other than income for the preceding year ended December 31st for the affected Dominion Companies.
(R)	Aviation	A combination of O&M as noted above and flight days for the previous two years.
(S)	Purchases	Dollar value of Dominion Company purchases for the preceding year ended December 31st.
(T)	Gas Volumes	Throughput of gas volumes purchased for each Dominion Company for the preceding year ended December 31st.

(b) Concept: DescriptionOfNonPowerGoodOrService

In 2021 and 2022, as a result of the merger integration with Dominion Energy, South Carolina Fuel Company, Inc. ("SCFC", an affiliate of DESC which is fully consolidated herein) transitioned from its legacy fuel management system to the system used by Dominion Energy and also integrated its cash management processes into those used by Dominion Energy. As a result, certain fuel and related transportation purchases were initially paid by South Carolina Generating Company, Inc. ("GENCO"). Further, certain acquisitions of fuel and related transportation services related to South Carolina Generating Company, Inc. were initially paid by SCFC. Cash corrections were made between GENCO and South Carolina Fuel Company during 2021 and 2022.

(c) Concept: DescriptionOfNonPowerGoodOrService

In 2021 and 2022, as a result of the merger integration with Dominion Energy, South Carolina Fuel Company, Inc. ("SCFC", an affiliate of DESC which is fully consolidated herein) transitioned from its legacy fuel management system to the system used by Dominion Energy and also integrated its cash management processes into those used by Dominion Energy. As a result, certain fuel and related transportation purchases were initially paid by South Carolina Generating Company, Inc. ("GENCO"). Further, certain acquisitions of fuel and related transportation services related to South Carolina Generating Company, Inc. were initially paid by SCFC. Cash corrections were made between GENCO and South Carolina Fuel Company during 2021 and 2022.

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

408.1 / 517 / 520 / 523 / 530 / 532 / 926.1 / 926.2 / 926.3 / 926.4 / 926.7 / 926.8