Georgia Power

Bin 10230
241 Ralph McGill Boulevard, NE
Atlanta, GA 30308-3374

April 15, 2025

Ms. Sallie Tanner
Executive Secretary
Georgia Public Service Commission
244 Washington Street, SW
Atlanta, GA 30334-5701

RE: 2024 Annual Report of Major Electric Utilities, Licensees and Others Federal Energy Regulatory Commission (FERC) Form No. 1

Dear Ms. Tanner:

Attached please find a copy of Georgia Power's FERC Form No. 1 Annual Report for the year ending December 31, 2024.

Please call me at 404-506-7106 with any questions regarding this filing.

Sincerely,

/s/ Jeremiah Haswell

Jeremiah C. Haswell
Director, Regulatory Affairs
jhaswell@southernco.com

SUPPLEMENTAL OATH

(By the President or other Chief Officer of the Respondent).

State of: Georgia

County of: Fulton

Kimberly S. Greene makes oath and says that she is
(Name of the Affiant)

Chairman, President and Chief Executive Officer of
(Official Title of the Affiant)

Georgia Power Company
(Exact Legal Title or Name of the Respondent)

that she has examined the foregoing report; that she believes that all statements of fact contained in the said report are true, and the said report is a correct statement of the business and affairs of the above named Respondent in respect to each and every matter set forth therein during the period from and including January 1, 2024 to and including December 31, 2024

Kimberly S. Greene
(Signature of Affiant)

Subscribed and sworn to before me, a Notary Public in and for the State and County above named, this 1st day of April 2025

My Commission expires: 1-25-2028

Katheryn M. Price

(Use an Impression Seal.)

KATHERYN M PRICE
NOTARY PUBLIC
SPALDING COUNTY, GA
MY COMMISSION EXPIRES
JANUARY 25 2028

(Signature of Officer authorized to administer oaths)

VERIFICATION

The foregoing report must be verified by the oath of the Officer having control of the accounting of the Respondent. It should be verified, also, by the oath of the president or Chief Officer of the Respondent. The oath required may be taken before any person authorized to administer an oath by the laws of the State in which the same is taken.

OATH

(To be made by the Officer having control of the accounting of the Respondent.)

State of: Georgia

County of: Fulton

Aaron P. Abramovitz **makes oath and says that he is**
(Name of the Affiant)

Executive Vice President, Chief Financial Officer, and Treasurer **of**
(Official Title of the Affiant)

Georgia Power Company **that it is his duty to have**
(Exact Legal Title or Name of the Respondent)

supervision over the books of account of the Respondent and that to the best of his knowledge and belief such books have, during the period covered by the foregoing report, been kept in good faith in accordance with the accounting and other orders of the Georgia Public Service Commission, effective during said period; that he has examined the said report, and to the best of his knowledge and belief the information contained in the said report is, insofar as it relates to matters of account, in accordance with the said books of account; that he believes that all other statements of fact contained in said report are true, and that the said report is a correct statement of the business and affairs of the above named Respondent in respect to each and every matter set forth therein during the period from and including
January 1, 2024 **to and including** December 31, 2024

Aaron P. Abramovitz
(Signature of Affiant)

Subscribed and sworn to before me, A Notary Public in and for the State and County above named, this 1st **day of** April 2025

My commission expires: 1-25-28

Katheryn M. Price
(Signature of Officer authorized to administer oaths)

(Use an Impression Seal.)



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
Georgia Power Company	End of: 2024/ Q4

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

GENERAL INFORMATION

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.

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:

one million megawatt hours of total annual sales,

100 megawatt hours of annual sales for resale,

500 megawatt hours of annual power exchanges delivered, or

500 megawatt hours of annual wheeling for others (deliveries plus losses).

What and Where to Submit

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.

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

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

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:

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

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

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 the List of Schedules, pages 2 and 3.

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).

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.

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

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

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.

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

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.

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

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.

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.

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

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

FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

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

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.

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.

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:

'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;

'Person' means an individual or a corporation;

'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;

'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; .....

"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

'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.

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..."

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.

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

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	02 Year/ Period of Report
Georgia Power Company	End of: 2024/ 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)
241 Ralph McGill Blvd, NE, Atlanta, GA 30308-3374

05 Name of Contact Person	06 Title of Contact Person
Kim Thomas	Financial Accounting and Reporting Manager

07 Address of Contact Person (Street, City, State, Zip Code)
241 Ralph McGill Blvd, NE, Atlanta, GA 30308-3374

08 Telephone of Contact Person, Including Area Code	09 This Report is An Original / A Resubmission	10 Date of Report (Mo, Da, Yr)
404-506-4885	(1) ☐ An Original (2) ☑ A Resubmission	04/03/2025

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	03 Signature	04 Date Signed (Mo, Da, Yr)
Adam D. Houston	Adam D. Houston	04/03/2025
02 Title		
Vice President and Comptroller		

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: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
	Identification	1	
	List of Schedules	2	
1	**General Information**	101	
2	**Control Over Respondent**	102	
3	**Corporations Controlled by Respondent**	103	
4	**Officers**	104	
5	**Directors**	105	
6	**Information on Formula Rates**	106	
7	**Important Changes During the Year**	108	
8	**Comparative Balance Sheet**	110	
9	**Statement of Income for the Year**	114	
10	**Statement of Retained Earnings for the Year**	118	
12	**Statement of Cash Flows**	120	
12	**Notes to Financial Statements**	122	
13	**Statement of Accum Other Comp Income, Comp Income, and Hedging Activities**	122a	
14	**Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep**	200	
15	**Nuclear Fuel Materials**	202	
16	**Electric Plant in Service**	204	
17	**Electric Plant Leased to Others**	213	
18	**Electric Plant Held for Future Use**	214	
19	**Construction Work in Progress-Electric**	216	
20	**Accumulated Provision for Depreciation of Electric Utility Plant**	219	
21	**Investment of Subsidiary Companies**	224	
22	**Materials and Supplies**	227	
23	**Allowances**	228	
24	**Extraordinary Property Losses**	230a	
25	**Unrecovered Plant and Regulatory Study Costs**	230b	

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	None
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	None
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	None
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	None
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	

60	**Monthly ISO/RTO Transmission System Peak Load**	400a	
61	**Electric Energy Account**	401a	
62	**Monthly Peaks and Output**	401b	
63	**Steam Electric Generating Plant Statistics**	402	
64	**Hydroelectric Generating Plant Statistics**	406	
65	**Pumped Storage Generating Plant Statistics**	408	
66	**Generating Plant Statistics Pages**	410	
66.1	**Energy Storage Operations (Large Plants)**	414	
66.2	**Energy Storage Operations (Small Plants)**	419	
67	**Transmission Line Statistics Pages**	422	Revised
68	**Transmission Lines Added During Year**	424	
69	**Substations**	426	
70	**Transactions with Associated (Affiliated) Companies**	429	
71	**Footnote Data**	450	
	Stockholders' Reports (check appropriate box)		
	Stockholders' Reports Check appropriate box: ☑ Two copies will be submitted ☐ No annual report to stockholders is prepared		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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.

Adam D. Houston

Vice President and Comptroller

241 Ralph McGill Blvd, NE, Atlanta, GA 30308-3374

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: GA

Date of Incorporation: 1930-06-26

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.

(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.

Electric light and power - Georgia

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: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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.

(a) Name of controlling corporation: The Southern Company (Southern Company), a Delaware corporation.

(b) Extent of control: All common stock of respondent is owned by Southern Company.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Southern Electric Generating Company	Public Utility	50	(a) (a)
2	Piedmont-Forrest Corporation	Subsidiary established for the purpose of handling various real estate related transactions.	100	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: FootnoteReferences

50.00% of Southern Electric Generating Company's capital stock is owned by Georgia Power Company and 50.00% is owned by Alabama Power Company.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

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	Chairman, President and Chief Executive Officer	Kimberly S. Greene	936,524		
2	Executive Vice President, Chief Financial Officer, and Treasurer	Aaron P. Abramovitz	433,782		
3	Executive Vice President External Affairs and Nuclear Development	Meredith M. Lackey	1,989		2024-01-01
4	Senior Vice President General Counsel, Corporate Secretary, and CCO	David E. Slovensky	426,462		
5	Senior Vice President, Human Resources	Lindsay Hill	333,799		
6	[a] Senior Vice President and Senior Production Officer - East Production Group	Roderick W. Anderson	371,985		
7	Senior Vice President, Transmission	Fran Forehand	371,460		
8	Senior Vice President, Customer Strategy and Solutions	Bentina Terry	1,518		2024-01-01
9	Senior Vice President, Customer Experience	Latanza W. Adjei	323,571	2024-01-01	
10	Senior Vice President External Affairs	Martin E. Kilpatrick, III	376,923	2024-01-15	
11	Senior Vice President Region External Affairs	Audrey D. King	282,106	2024-01-01	
12	Senior Vice President, Distribution	Tami M. Barron	436,902	2024-01-01	
13	Vice President, Corporate Responsibility	Jason T. Cuevas	312,391	2024-01-01	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OfficerTitle

Salary is allocated to multiple companies.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Kimberly S. Greene, Chairman, President and CEO	241 Ralph McGill Blvd NE, BIN 10240 Atlanta, GA 30308	true	true
2	Jill Bullock	N/A	false	false
3	Mark L. Burns	500 Gulfstream Road, Savannah, GA 31408	false	false
4	Thomas M. Holder	3300 Riverwood Pkwy, Ste. 1200, Atlanta, GA 30339	false	false
5	Kessel D. Stelling, Jr.	1111 Bay Avenue, Suite 500, Columbus, GA 31901	true	false
6	Charles K. Tarbutton	750 Sparta Road, Sandersville, GA 31082	true	false
7	Clyde C. Tuggle	296 Brogdon Road Suwanee, GA 30024	true	false
8	Andrew W. Evans	N/A	false	false
9	Steven R. Ewing	N/A	false	false
10	T. Dallas Smith	101 Marietta Street NW Atlanta, GA 30303	false	false

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Georgia Power Company Rate Schedule Federal Energy Regulatory Commission (FERC) No. 793	Initial docket not available on eLibrary
2	Georgia Power Company Rate ScheduleFERC No. 833	ER99-3051-000
3	Georgia Power Company Rate ScheduleFERC No. 835	ER02-1574-000
4	Georgia Power Company Rate Schedule No. 850	ER24-2840-000
5	Tariff Volume No. 5, Southern Companies OATT	ER24-1831-000
6	Cost Based Rate Tariff,Southern's Tariff Volume No. 11	ER10-2925-000
7	Southern Company Services, Inc.Tariff Volume No. 13	ER20-1735-002
8	Southern Operating CompaniesRate Schedule No. 33	ER19-1000-000
9	Southern Company Services, Inc.Rate Schedule No. 138	ER22-1820-001
10	Georgia Power Company Rate Schedule No. 836	ER25-212-000
11	Georgia Power Company Rate Schedule No. 837	ER25-212-000
12	Georgia Power Company Rate Schedule No. 838	ER25-212-000

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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

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	20231101-5258	11/01/2023	ER10-203-000	2024 OATT Informational Filing	Tariff Volume No. 5, Southern Companies OATT
2	20240501-5495	05/01/2024	ER10-203-000	2023 OATT True-Up Filing	Tariff Volume No. 5, Southern Companies OATT
3	20231101-5260	11/01/2023	ER10-171-000	2024 Intercompany Interchange Contract Informational Filing	Southern Company Services, Inc. Rate Schedule No. 138
4	20231130-5388	11/30/2023	ER10-171-000	Errata to 2024 Intercompany Interchange Contract	Southern Company Services, Inc. Rate Schedule No. 138
5	20241025-5052	10/25/2024	ER25-212-000	2024 Post-Retirement Benefits Other Than Pensions Filing	Georgia Power Company Rate Schedule Nos. 836, 837, and 838

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	None			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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. None

2. None

3. In the second quarter, Georgia Power sold seventy-one 46kV, four 69kV, twenty-seven 115kV, and one 230kV transmission lines and during the fourth quarter, under Docket No. AC25-5-000, Georgia Power requested and the Commission approved proposed accounting entries to clear Account 102, Electric Plant Purchased or Sold for approximately $351 million.

4. None

5. None

6. The following obligations were incurred as a result of the issuance of securities pursuant to Federal Energy Regulatory Commission approval:

Georgia Power Company issued commercial paper from time to time during the year ended December 31, 2024. The largest amount of such commercial paper outstanding at any given time during such period was approximately
$811 million.

In January 2024, Georgia Power borrowed an additional $150 million pursuant to a short-term uncommitted bank credit arrangement bearing interest at a mutually agreed upon rate and payable on demand.

In June 2024, Georgia Power entered into a $200 million short-term floating rate bank loan bearing interest based on term SOFR.

The following obligations were incurred as a result of the issuance of securities pursuant to Georgia Public Service Commission approval:

In February 2024, Georgia Power issued $500 million aggregate principal amount of Series 2024A 5.004% Senior Notes due February 23, 2027 and $900 million aggregate principal amount of Series 2024B 5.250% Senior Notes due March 15, 2034.

In November 2024, Georgia Power issued approximately $117 million aggregate principal amount of Series 2024C Floating Rate Senior Notes due November 15, 2074.

In December 2024, Georgia Power issued $600 million aggregate principal amount of Series 2024D 4.55% Senior Notes due March 15, 2030.

7. None

8. None
9. See Note 3 to the Financial Statements for a description of certain legal proceedings.
10. None
12. See pages 122 through 123.
13. Effective January 1, 2024, T. Dallas Smith was elected as a Director Effective January 1, 2024, Meredith M. Lackey resigned as Executive Vice President Effective January 1, 2024, Betina C. Terry resigned as Senior Vice President Effective January 1, 2024, Charles E. Sutlive resigned as Vice President Effective January 1, 2024, Doug P. Jenkins resigned as Vice President Effective January 1, 2024, Audrey D. King was elected as Senior Vice President Effective January 1, 2024, Latanza W. Adjei was elected as Senior Vice President Effective January 1, 2024, Tami M. Barron was elected as Senior Vice President Effective January 1, 2024, Fredie V. Carmichael was elected as Vice President Effective January 15, 2024, Martin E. Kilpatrick, III was elected as Senior Vice President Effective February 1, 2024, Joshua J. Mason was elected Assistant Treasurer Effective April 1, 2024, P. Chris Caldwell resigned as Vice President Effective April 1, 2024, Rachel J. Williams was elected as Vice President Effective August 19, 2024, Scott A. Gammill was elected as Vice President
14. N/A

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	57,046,555,928	50,978,886,183
3	Construction Work in Progress (107)	200	3,211,575,035	4,987,468,923
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		60,258,130,963	55,966,355,106
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200	14,597,089,190	14,000,522,463
6	Net Utility Plant (Enter Total of line 4 less 5)		45,661,041,773	41,965,832,643
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202	65,452,125	123,568,334
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		269,742,114	246,947,277
9	Nuclear Fuel Assemblies in Reactor (120.3)		671,958,269	566,785,247
10	Spent Nuclear Fuel (120.4)		85,078,302	45,418,490
11	Nuclear Fuel Under Capital Leases (120.6)			
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202	481,458,915	377,554,986
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		610,771,895	605,164,362
14	Net Utility Plant (Enter Total of lines 6 and 13)		46,271,813,668	42,570,997,005
15	Utility Plant Adjustments (116)			
16	Gas Stored Underground - Noncurrent (117)			
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		188,743,237	159,439,589
19	(Less) Accum. Prov. for Depr. and Amort. (122)		7,966,065	15,205,867
20	Investments in Associated Companies (123)		15,086,675	12,105,898
21	Investment in Subsidiary Companies (123.1)	224	45,415,088	52,399,208
23	Noncurrent Portion of Allowances	228		
24	Other Investments (124)		12,363,305	11,106,903
25	Sinking Funds (125)			
26	Depreciation Fund (126)			
27	Amortization Fund - Federal (127)			
28	Other Special Funds (128)		3,118,316,095	(b) 2,967,948,441
29	Special Funds (Non Major Only) (129)			
30	Long-Term Portion of Derivative Assets (175)			

31	Long-Term Portion of Derivative Assets - Hedges (176)		13,306,802	9,825,805
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		3,385,265,137	3,197,619,977
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)			
35	Cash (131)		62,328,389	9,236,353
36	Special Deposits (132-134)		21,011,508	37,201,180
37	Working Fund (135)			
38	Temporary Cash Investments (136)		35,000,000	
39	Notes Receivable (141)			
40	Customer Accounts Receivable (142)		1,713,169,207	1,540,769,397
41	Other Accounts Receivable (143)		171,329,236	179,156,533
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		14,967,120	4,000,360
43	Notes Receivable from Associated Companies (145)			
44	Accounts Receivable from Assoc. Companies (146)		65,284,886	51,084,909
45	Fuel Stock (151)	227	371,907,472	468,132,742
46	Fuel Stock Expenses Undistributed (152)	227	5,459,044	4,961,210
47	Residuals (Elec) and Extracted Products (153)	227		
48	Plant Materials and Operating Supplies (154)	227	967,915,466	883,001,663
49	Merchandise (155)	227		
50	Other Materials and Supplies (156)	227	113,505	263,239
51	Nuclear Materials Held for Sale (157)	202/227		
52	Allowances (158.1 and 158.2)	228	7,208,067	7,223,951
53	(Less) Noncurrent Portion of Allowances	228		
54	Stores Expense Undistributed (163)	227	(9,110)	12,811
55	Gas Stored Underground - Current (164.1)			
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)			
57	Prepayments (165)		35,381,002	118,270,591
58	Advances for Gas (166-167)			
59	Interest and Dividends Receivable (171)		77,920	
60	Rents Receivable (172)		27,237,443	25,218,067
61	Accrued Utility Revenues (173)		375,479,780	309,903,728
62	Miscellaneous Current and Accrued Assets (174)		115,283,178	90,204,515
63	Derivative Instrument Assets (175)			533,845
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)			

65	Derivative Instrument Assets - Hedges (176)		19,045,679	11,891,102
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176)		13,306,802	9,825,805
67	Total Current and Accrued Assets (Lines 34 through 66)		3,964,948,750	3,723,239,671
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		123,440,774	121,537,906
70	Extraordinary Property Losses (182.1)	230a		
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b		
72	Other Regulatory Assets (182.3)	232	8,398,375,276	7,618,024,924
73	Prelim. Survey and Investigation Charges (Electric) (183)		74,764,269	26,106,826
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)			
75	Other Preliminary Survey and Investigation Charges (183.2)			
76	Clearing Accounts (184)		(799,635)	(681,863)
77	Temporary Facilities (185)			
78	Miscellaneous Deferred Debits (186)	233	896,705,002	1,580,154,688
79	Def. Losses from Disposition of Utility Plt. (187)			
80	Research, Devel. and Demonstration Expend. (188)	352		
81	Unamortized Loss on Reaquired Debt (189)		182,687,028	197,335,147
82	Accumulated Deferred Income Taxes (190)	234	[a]1,445,250,307	1,504,090,951
83	Unrecovered Purchased Gas Costs (191)			
84	Total Deferred Debits (lines 69 through 83)		11,120,423,021	11,046,568,579
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		64,742,450,576	60,538,425,232

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

ACCUMULATED DEFERRED INCOME TAXES (ACCOUNT 190)	BALANCE AT BEG OF YEAR	BALANCE AT END OF YEAR
Accrual for Uncollectibles	$ 1,018,960	$ 3,747,816
Accumulated Rate Refund Georgia Public Service Commission	$ 12	$ 1,244
Affirmative Adjustments*	$ 8,478,950	$ —
Capacity Buybacks*	$ —	$ —
Capitalized Purchase Power Agreement Southern Power Co	$ 8,878,525	$ 7,702,895
Deferred Revenues - Electric	$ 981,932	$ (7,938,864)
Demand Side Management Recovery	$ 11,673,980	$ 13,143,149
FAS 133 Mark to Market*	$ 7,776,485	$ 8,453,921
Health Reimbursement Accrual	$ 598,744	$ 584,486
Income Taxes Deferred - Electric (OATT Included)	$ 158,582,525	$ 158,276,089
Income Taxes Deferred - Electric (OATT Excluded)	$ 94,265,490	$ 76,491,728
Protected Gross Up EADIT	$ 530,655,047	$ 492,900,313
Income Taxes Deferred - CWIP Electric	$ (8,376,711)	$ (290,564)
Income Taxes Deferred - Non Electric*	$ (19,793,690)	$ (28,698,853)
Income Taxes Deferred - CWIP Non Electric*	$ (16,158,001)	$ —
Injuries & Damages Reserve	$ 696,625	$ (10,670,864)
Nuclear Construction Cost Recovery Over/Under Recovery	$ —	$ —
Other Comprehensive Income - Hedge Settlement	$ 3,038,900	$ (4,952,159)
Other Basis Differences	$ 77,408,551	$ 78,271,629
Accrued Liabilities - Electric	$ 114,650,508	$ 80,776,983
Accrued Liabilities - Non Electric*	$ 16,445,346	$ 27,374,480
Environmental Remediation (RBA Order)	$ (5,133,539)	$ (3,980,559)
Storm Damage	$ —	$ —
Tax Credit Carry Forward - Electric	$ 363,710,569	$ 387,149,475
Tax Credit Carry Forward - Non Electric*	$ 160,032,604	$ 125,756,902
Unbilled Fuel Revenues	$ 31,714,873	$ 49,330,885
Unprotected Gross Up Deficient EADIT NCCR	$ (37,055,734)	$ (33,803,978)
Unprotected State Gross Up EADIT OATT Included	$ —	$ 19,154,141
Unprotected State Gross Up EADIT OATT Excluded	$ —	$ 6,470,012
Total	$ 1,504,090,951	$ 1,445,250,307
*Other Income and Deductions		
Classification of Totals:		
Federal Income Tax	$ 828,576,722	$ 848,777,309
State Income Tax	$ 675,514,229	$ 596,472,998

(b) Concept: OtherSpecialFunds

Other Special Funds (128)	**December 31, 2023**
Restricted Cash	$ 28,657,712
External Trusts	2,939,290,729
Total Other Special Funds (128)	**$ 2,967,948,441**

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	398,473,175	398,473,175
3	Preferred Stock Issued (204)	250		
4	Capital Stock Subscribed (202, 205)			
5	Stock Liability for Conversion (203, 206)			
6	Premium on Capital Stock (207)		8,664,636	8,664,636
7	Other Paid-In Capital (208-211)	253	19,698,739,336	17,914,475,721
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254b		
11	Retained Earnings (215, 215.1, 216)	118	3,533,387,133	3,034,736,783
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118	28,915,088	35,899,208
13	(Less) Reacquired Capital Stock (217)	250		
14	Noncorporate Proprietorship (Non-major only) (218)			
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	12,645,678	(9,477,463)
16	Total Proprietary Capital (lines 2 through 15)		23,680,825,046	21,382,772,060
17	**LONG-TERM DEBT**			
18	Bonds (221)	256	100,000,000	100,000,000
19	(Less) Reacquired Bonds (222)	256	100,000,000	100,000,000
20	Advances from Associated Companies (223)	256		
21	Other Long-Term Debt (224)	256	18,232,722,112	16,601,214,069
22	Unamortized Premium on Long-Term Debt (225)		2,436,166	2,578,134
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		23,497,232	21,402,810
24	Total Long-Term Debt (lines 18 through 23)		18,211,661,046	16,582,389,393
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)		1,401,078,930	962,010,262
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		16,370,485	56,079,551
29	Accumulated Provision for Pensions and Benefits (228.3)		1,154,524,035	1,282,371,802

30	Accumulated Miscellaneous Operating Provisions (228.4)			
31	Accumulated Provision for Rate Refunds (229)		(31,699,336)	3,855,051
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		9,493,389	42,242,787
34	Asset Retirement Obligations (230)		5,414,874,898	5,665,310,299
35	Total Other Noncurrent Liabilities (lines 26 through 34)		7,964,642,401	8,011,869,752
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Notes Payable (231)		200,000,000	520,000,000
38	Accounts Payable (232)		1,803,420,795	1,117,804,471
39	Notes Payable to Associated Companies (233)			810,595,000
40	Accounts Payable to Associated Companies (234)		983,940,656	839,901,727
41	Customer Deposits (235)		256,440,927	249,667,033
42	Taxes Accrued (236)	262	803,240,718	581,916,137
43	Interest Accrued (237)		190,363,137	175,033,552
44	Dividends Declared (238)			
45	Matured Long-Term Debt (239)			
46	Matured Interest (240)			
47	Tax Collections Payable (241)		33,273,318	28,768,959
48	Miscellaneous Current and Accrued Liabilities (242)		539,967,446	492,370,168
49	Obligations Under Capital Leases-Current (243)		188,541,747	152,189,061
50	Derivative Instrument Liabilities (244)		1,262,063	
51	(Less) Long-Term Portion of Derivative Instrument Liabilities			
52	Derivative Instrument Liabilities - Hedges (245)		41,178,240	124,070,993
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		9,493,389	42,242,787
54	Total Current and Accrued Liabilities (lines 37 through 53)		5,032,135,658	5,050,074,314
55	**DEFERRED CREDITS**			
56	Customer Advances for Construction (252)		71,532,396	103,078,581
57	Accumulated Deferred Investment Tax Credits (255)	266	342,926,296	325,679,523
58	Deferred Gains from Disposition of Utility Plant (256)			
59	Other Deferred Credits (253)	269	357,785,663	229,202,535
60	Other Regulatory Liabilities (254)	278	3,250,841,066	3,331,057,051
61	Unamortized Gain on Reacquired Debt (257)		3,666	14,447
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272	483,444,657	529,573,839
63	Accum. Deferred Income Taxes-Other Property (282)		3,901,436,675	3,508,541,899

64	Accum. Deferred Income Taxes-Other (283)		1,445,216,006	1,484,171,838
65	Total Deferred Credits (lines 56 through 64)		9,853,186,425	9,511,319,713
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		64,742,450,576	60,538,425,232

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 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) t 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) tl 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

Do not report fourth quarter data in columns (e) and (f)
Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility column in a similar manner department. Spread the amount(s) over Lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
Use page 122 for important notes regarding the statement of income for any account thereof.
Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be 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 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 with respect to power or gas purchases.
Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proce revenues received or costs incurred for power or gas purchases, and a summary of the adjustments made to balance sheet, income, and expense ac
If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
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, inclu allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to th

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 Utiity Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)
1	UTILITY OPERATING INCOME									
2	Operating Revenues (400)	300	11,064,821,255	9,901,740,533			11,064,821,255	9,901,740,533		
3	Operating Expenses									
4	Operation Expenses (401)	320	4,426,790,935	4,310,438,388			4,426,790,935	4,310,438,388		
5	Maintenance Expenses (402)	320	676,914,330	503,403,501			676,914,330	503,403,501		
6	Depreciation Expense (403)	336	1,509,442,181	1,335,454,797			1,509,442,181	1,335,454,797		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336	27,077,698	29,215,684			27,077,698	29,215,684		

8	Amort. & Depl. of Utility Plant (404-405)	336	63,559,610	63,664,133			63,559,610	63,664,133		
9	Amort. of Utility Plant Acq. Adj. (406)	336	58,323	642,691			58,323	642,691		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)									
11	Amort. of Conversion Expenses (407.2)									
12	Regulatory Debits (407.3)		300,501,333	340,934,732			300,501,333	340,934,732		
13	(Less) Regulatory Credits (407.4)		332,097,725	315,146,948			332,097,725	315,146,948		
14	Taxes Other Than Income Taxes (408.1)	262	645,294,370	539,316,945			645,294,370	539,316,945		
15	Income Taxes - Federal (409.1)	262	228,592,848	207,197,765			228,592,848	207,197,765		
16	Income Taxes - Other (409.1)	262	25,650,554	55,563,409			25,650,554	55,563,409		
17	Provision for Deferred Income Taxes (410.1)	234, 272	1,197,286,971	784,036,268			1,197,286,971	784,036,268		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272	937,183,946	579,857,490			937,183,946	579,857,490		
19	Investment Tax Credit Adj. - Net (411.4)	266	(35,251,079)	(10,981,079)			(35,251,079)	(10,981,079)		
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,563,222	928,305			1,563,222	928,305		
21	Losses from Disp. of Utility Plant (411.7)									
22	(Less) Gains from Disposition of Allowances (411.8)		183	103,403			183	103,403		
23	Losses from Disposition of Allowances (411.9)									
24	Accretion Expense (411.10)		231,909,439	230,524,826			231,909,439	230,524,826		

25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		8,026,982,437	7,493,375,914			8,026,982,437	7,493,375,914		
27	Net Util Oper Inc (Enter Tot line 2 less 25)		3,037,838,818	2,408,364,619			3,037,838,818	2,408,364,619		
28	Other Income and Deductions									
29	Other Income									
30	Nonutilty Operating Income									
31	Revenues From Merchandising, Jobbing and Contract Work (415)		299,882,471	223,850,482						
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		253,147,989	181,276,630						
33	Revenues From Nonutility Operations (417)									
34	(Less) Expenses of Nonutility Operations (417.1)		3,448,290	2,966,713						
35	Nonoperating Rental Income (418)		18,363,969	17,979,149						
36	Equity in Earnings of Subsidiary Companies (418.1)	119	5,831,360	7,109,580						
37	Interest and Dividend Income (419)		11,946,209	11,587,161						
38	Allowance for Other Funds Used During Construction (419.1)		151,611,782	147,082,877						
39	Miscellaneous Nonoperating Income (421)		22,891,388	6,041,849						
40	Gain on Disposition of Property (421.1)		115,900,456	25,980,365						

41	TOTAL Other Income (Enter Total of lines 31 thru 40)		369,831,356	255,388,120						
42	Other Income Deductions									
43	Loss on Disposition of Property (421.2)		165,648	4,028,126						
44	Miscellaneous Amortization (425)		9,780	16,487						
45	Donations (426.1)		13,460,068	8,069,609						
46	Life Insurance (426.2)		(423,371)	(245,535)						
47	Penalties (426.3)		614,926	201,218						
48	Exp. for Certain Civic, Political & Related Activities (426.4)		9,612,182	11,313,873						
49	Other Deductions (426.5)		10,553,782	(80,026,363)						
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		33,993,015	(56,642,585)						
51	Taxes Applic. to Other Income and Deductions									
52	Taxes Other Than Income Taxes (408.2)	262	15,803,626	15,001,791						
53	Income Taxes-Federal (409.2)	262	(29,134,662)	(2,354,936)						
54	Income Taxes-Other (409.2)	262	26,076,323	(18,126,521)						
55	Provision for Deferred Inc. Taxes (410.2)	234, 272	204,084,484	114,431,710						
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272	112,381,667	112,239,674						
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)		104,448,104	(3,287,630)						
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		231,390,237	315,318,335						
61	Interest Charges									
62	Interest on Long-Term Debt (427)		699,601,171	582,910,407						
63	Amort. of Debt Disc. and Expense (428)		14,532,548	11,799,979						
64	Amortization of Loss on Reaquired Debt (428.1)		14,743,235	15,787,836						
65	(Less) Amort. of Premium on Debt-Credit (429)		141,968	116,787						
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		10,781	37,704						
67	Interest on Debt to Assoc. Companies (430)		10,069,022	13,616,515						
68	Other Interest Expense (431)		41,511,029	90,653,443						
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		53,773,430	70,545,178						
70	Net Interest Charges (Total of lines 62 thru 69)		726,530,826	644,068,511						
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		2,542,698,229	2,079,614,443						
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	0							
77	Extraordinary Items After Taxes (line 75 less line 76)									
78	Net Income (Total of line 71 and 77)		2,542,698,229	2,079,614,443						

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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		2,960,528,828	2,734,899,204
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Adjustments to Retained Earnings Credit			
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adjustments to Retained Earnings Debit			
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		2,536,866,869	2,072,504,863
17	Appropriations of Retained Earnings (Acct. 436)			
17.1	Hydro Amortization Reserve, Federal		(4,923,393)	(3,395,345)
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		(4,923,393)	(3,395,345)
23	Dividends Declared-Preferred Stock (Account 437)			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
30.1	[(a)] Common Stock (all owned by Southern Company)		(2,051,032,000)	(1,855,420,000)
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		(2,051,032,000)	(1,855,420,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		12,815,480	11,940,106
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		3,454,255,784	2,960,528,828
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)		79,131,349	74,207,955
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		79,131,349	74,207,955
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		3,533,387,133	3,034,736,783
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account Report only on an Annual Basis, no Quarterly)			
49	Balance-Beginning of Year (Debit or Credit)		35,899,208	40,729,734
50	Equity in Earnings for Year (Credit) (Account 418.1)		5,831,360	7,109,580
51	(Less) Dividends Received (Debit)		12,815,480	11,940,106
52	TOTAL other Changes in unappropriated undistributed subsidiary earnings for the year			
53	Balance-End of Year (Total lines 49 thru 52)		28,915,088	35,899,208

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DividendsDeclaredCommonStockDescription

Note 1: Dividend Declarations

	2024	2023
Common Stock	$ 2,051,032,000	$ 1,855,420,000

All common stock of the respondent is owned by Southern Company.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)	2,542,698,229	2,079,614,443
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,690,891,648	1,524,369,889
5	Amortization of (Specify) (footnote details)		
5.1	Amortization of		
5.2	Nuclear Fuel	213,385,139	144,146,696
5.3	Other	331,019,127	329,772,708
8	Deferred Income Taxes (Net)	369,177,147	184,932,165
9	Investment Tax Credit Adjustment (Net)	(23,994,958)	10,457,571
10	Net (Increase) Decrease in Receivables	468,909,502	250,254,426
11	Net (Increase) Decrease in Inventory	14,698,586	(342,187,959)
12	Net (Increase) Decrease in Allowances Inventory	15,883	15,569
13	Net Increase (Decrease) in Payables and Accrued Expenses	795,029,236	(76,118,794)
14	Net (Increase) Decrease in Other Regulatory Assets	(638,822,114)	(48,614,816)
15	Net Increase (Decrease) in Other Regulatory Liabilities	(130,458,391)	(123,553,797)
16	(Less) Allowance for Other Funds Used During Construction	151,611,782	147,082,877
17	(Less) Undistributed Earnings from Subsidiary Companies	5,831,361	7,109,580
18	Other (provide details in footnote):		
18.1	Other (provide details in footnote):		
18.2	Estimated Loss on Plant Vogtle Units 3 and 4	(21,328,800)	(67,510,140)
18.3	Other, Net	[a](626,810,456)	[f](914,478,787)
22	Net Cash Provided by (Used in) Operating Activities (Total of Lines 2 thru 21)	4,826,966,635	2,796,906,717
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		

26	Gross Additions to Utility Plant (less nuclear fuel)	(4,794,586,681)	(4,835,206,002)
27	Gross Additions to Nuclear Fuel	(206,330,627)	(143,710,608)
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	(39,751,880)	(35,358,116)
30	(Less) Allowance for Other Funds Used During Construction	(151,611,782)	(147,082,877)
31	Other (provide details in footnote):		
31.1	Other (provide details in footnote):		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	(4,889,057,406)	(4,867,191,849)
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	(3,135,383)	(3,048,072)
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	28,883,702	6,649,442
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	39,508,758	43,767,779
53	Other (provide details in footnote):		
53.1	Fixed Assets	356,969,037	59,408,086
53.2	Other (provide details in footnote):	[b](462,746,751)	[g](363,754,491)
57	Net Cash Provided by (Used in) Investing Activities (Total of lines 34 thru 55)	(4,929,578,043)	(5,124,169,105)
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	2,117,087,000	2,679,485,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
64.1	Other (provide details in footnote):		
64.2	Short-Term Borrowings	350,000,000	350,000,000
66	Net Increase in Short-Term Debt (c)		810,595,000

67	Other (provide details in footnote):		
67.1	Other (provide details in footnote):		
67.2	Capital Contributions from Parent Company	1,780,123,565	2,290,884,036
70	Cash Provided by Outside Sources (Total 61 thru 69)	4,247,210,565	6,130,964,036
72	Payments for Retirement of:		
73	Long-term Debt (b)	(485,578,957)	(885,578,957)
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
76.1	Other (provide details in footnote):	(c)(84,148,549)	(b)(37,782,543)
76.2	Short-Term Borrowings	(670,000,000)	(1,430,000,000)
78	Net Decrease in Short-Term Debt (c)	(810,595,000)	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	(2,051,032,000)	(1,855,420,000)
83	Net Cash Provided by (Used in) Financing Activities (Total of lines 70 thru 81)	145,856,059	1,922,182,536
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)	43,244,651	(405,079,852)
88	Cash and Cash Equivalents at Beginning of Period	(d)75,095,246	480,175,098
90	Cash and Cash Equivalents at End of Period	(e)118,339,897	(i)75,095,246

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Other Operating Activities		**Year-to-Date December 2024**
Pension, Postretirement, & Other Employee Benefits	$	(285,949,794)
Asset Retirement Obligation Settlements		(270,159,762)
Net (Gain)/Loss on Asset Sales		(115,625,058)
Plant Dismantlement Costs Reclassed from Cost of Removal		(35,300,626)
Contract Assets		(30,439,392)
Noncash Gain for CIAC (eliminating net income impact)		(21,003,399)
SNC Inventory Progress Payments		(11,126,946)
Jobbing Holding (Various)		(5,847,002)
Spent Fuel Dry Cask Storage		(4,259,603)
Affiliate Company Earnings		(4,090,109)
Prepayments		(3,392,698)
Worker's Comp Reserve		(2,058,454)
Capacity RFP Bid Bond		52,669,261
Prepaid Income Taxes - Federal		25,552,885
Hedge Settlements		24,910,267
Prepaid Income Taxes - State		16,498,594
Stock Option Expense		13,236,438
Provision for Uncollectible Accounts		10,966,760
Noncash V4 Online Station Service & Gross Generation		5,761,091
Unregulated Sales Commission		4,790,697
Outdoor Lighting NEC Jobbing		2,781,959
Noncash YTD Property Write Downs (eliminating net income impact)		2,716,721
Other Operating		2,557,714
Total Other Operating Activities	**$**	**(626,810,456)**

(b) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Other Investing Activities		**Year-to-Date December 2024**
Nuclear Decommissioning Trust (NDT) Fund Purchases	$	(958,195,939)
Cost of Removal, Net of Salvage		(335,965,017)
Long-Term Service Agreement		(73,851,099)
Preliminary Survey and Investigation		(51,096,277)
NDT Fund Sales		942,435,750
SEGCO Dividends		13,602,527
Other Investing		323,304
Total Other Investing Activities	**$**	**(462,746,751)**

(c) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Other Financing Activities		**Year-to-Date December 2024**
Customer Advances	$	(33,046,318)
Finance Lease Redemptions		(23,493,826)
Debt Issuance Costs		(18,624,955)
Performance Shares Payroll Taxes		(9,096,388)
Other Financing		112,938
Total Other Financing Activities	**$**	**(84,148,549)**

(d) Concept: CashAndCashEquivalents

		Year-to-Date December 2023
Supplemental Cash Flow Information		
Cash Paid During the Period for:		
Interest	$	592,462,994
Income Taxes (Net of Refunds)		219,591,780
Noncash Transactions:		
Accrued Property Additions at End of Period	$	680,266,331
Right-of-Use Assets Obtained Under Operating Leases		25,961,030
Right-of-Use Assets Obtained Under Finance Leases		18,061,907
Balance Sheet		
Other Special Funds - Restricted Cash (128)	$	28,657,712
Cash (131)		9,236,353
Other Special Deposits - Restricted Cash (134)		37,201,181
Working Funds (135)		—
Temporary Cash Investments (136)		—
Cash Flow Cash, Cash Equivalents, and Restricted Cash	**$**	**75,095,246**

(e) Concept: CashAndCashEquivalents

		Year-to-Date December 2024
Supplemental Cash Flow Information		
Cash Paid (Received) During the Period for:		
Interest	$	680,051,427
Income Taxes, Net (excludes credit transfers)		(14,344,907)
Noncash Transactions:		
Accrued Property Additions at End of Period	$	739,135,801
Right-of-Use Assets Obtained Under Operating Leases		609,381,772
Right-of-Use Assets Obtained Under Finance Leases		44,219,139
Balance Sheet		
Other Special Funds - Restricted Cash (128)	$	—
Cash (131)		62,328,389
Other Special Deposits - Restricted Cash (134)		21,011,508
Working Funds (135)		—
Temporary Cash Investments (136)		35,000,000
Cash Flow Cash, Cash Equivalents, and Restricted Cash	**$**	**118,339,897**

(f) Concept: OtherAdjustmentsToCashFlowsFromOperatingActivities

Other Operating Activities		Year-to-Date December 2023
Asset Retirement Obligation Settlements	$	(303,619,993)
Pension, Postretirement, & Other Employee Benefits		(270,388,159)
Retail Fuel Cost Under Recovery - Long-Term		(156,545,636)
Storm Damage Reserve		(83,324,714)
Contract Assets		(32,751,608)
Plant Dismantlement Costs Reclassed from Cost of Removal		(29,667,329)
Net (Gain)/Loss on Asset Sales		(21,862,926)
Spent Fuel Dry Cask Storage		(12,802,544)
Prepaid Income Taxes - Federal		(7,725,290)
Jobbing Holding (Various)		(6,693,142)
Noncash Vogtle 3&4 AFUDC-Debt		(6,300,500)
SNC Inventory Progress Payments		(5,052,218)
Prepaid Income Taxes - State		(4,519,120)
Distributed Generation Collateral		(3,871,964)
Worker's Comp Reserve		(3,654,458)
Prepayments		(3,550,268)
Hedge Settlements		(2,548,313)
Bank Line of Credit Fees		(2,501,844)
Outdoor Lighting NEC Jobbing		(2,329,500)
Stock Option Expense		15,468,725
Noncash V3 Online Station Service & Gross Generation		13,467,806
SEGCO Dividends		13,158,207
Other Operating		3,136,001
Total Other Operating Activities	**$**	**(914,478,787)**

(g) Concept: OtherAdjustmentsToCashFlowsFromInvestmentActivities

Other Investing Activities		Year-to-Date December 2023
Nuclear Decommissioning Trust (NDT) Fund Purchases	$	(841,384,032)
Cost of Removal, Net of Salvage		(278,747,013)
Long-Term Service Agreement		(49,372,996)
Preliminary Survey and Investigation		(5,326,925)
Oconee 1 LLC Loan		(5,000,000)
Prepaid Construction Insurance		(4,320,935)
NDT Fund Sales		820,904,966
Other Investing		(507,556)
Total Other Investing Activities	**$**	**(363,754,491)**

(h) Concept: OtherRetirementsOfBalancesImpactingCashFlowsFromFinancingActivities

Other Financing Activities		Year-to-Date December 2023
Debt Issuance Costs	$	(16,963,654)
Finance Lease Redemptions		(16,121,739)
Performance Shares Payroll Taxes		(8,325,480)
Customer Advances		3,607,913
Other Financing		20,417
Total Other Financing Activities	**$**	**(37,782,543)**

(i) Concept: CashAndCashEquivalents

		Year-to-Date December 2023
Supplemental Cash Flow Information		
Cash Paid During the Period for:		
Interest	$	592,462,994
Income Taxes (Net of Refunds)		219,591,780
Noncash Transactions:		
Accrued Property Additions at End of Period	$	680,266,331
Right-of-Use Assets Obtained Under Operating Leases		25,961,030
Right-of-Use Assets Obtained Under Finance Leases		18,061,907
Balance Sheet		
Other Special Funds - Restricted Cash (128)	$	28,657,712
Cash (131)		9,236,353
Other Special Deposits - Restricted Cash (134)		37,201,181
Working Funds (135)		—
Temporary Cash Investments (136)		—
Cash Flow Cash, Cash Equivalents, and Restricted Cash	**$**	**75,095,246**

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 Commission 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.

Notes to the Financial Statements
for
The Southern Company and Subsidiary Companies
Alabama Power Company
Georgia Power Company
Mississippi Power Company
Southern Power Company and Subsidiary Companies
Southern Company Gas and Subsidiary Companies

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1	Summary of Significant Accounting Policies
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7	Consolidated Entities and Equity Method Investments
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Index to Applicable Notes to Financial Statements by Registrant

The following notes to the financial statements are a combined presentation; however, information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf and each Registrant makes no representation as to information related to the other Registrants. The table below indicates the Registrants to which each note applies.

	Applicable Notes															
Registrant	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Southern Company	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Alabama Power	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•
Georgia Power	•	•	•	•	•	•	•	•	•	•	•	•	•	•		•
Mississippi Power	•	•	•	•	•	•		•	•	•	•	•	•	•	•	•
Southern Power	•		•	•	•	•	•	•	•	•	•	•	•	•	•	•
Southern Company Gas	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•	•

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in the applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States (GAAP). These requirements as they relate to the attached financial statements differ from GAAP primarily in:

- The classification of the components of:
  - Accumulated deferred income taxes
  - Uncertain tax positions
  - Certain miscellaneous current and accrued liabilities
  - Prepaid assets
  - Pension and post-retirement benefit obligations
  - Maturities of long-term debt
  - Deferred debits and credits
  - Certain regulatory assets and liabilities
- The presentation of:
  - Majority-owned subsidiaries and certain other investments
  - Certain other cost of removal obligations
  - Post-retirement defined benefit plans
  - Unamortized debt expense
  - Unamortized discounts for certain short-term debt
  - Taxes applicable to other income and deductions
  - Gains and losses on disposition of property
  - Line of credit commitment fees and associated expenses
  - Certain disallowances on operations and maintenance expenses
  - The fair value amounts of derivative assets and liabilities
  - ASU 2016-02, Leases (Topic 842)
  - ASU 2018-15, Intangibles – Goodwill and Other – Internal-Use Software (Topic 350)
  - ASC 606, Revenue from Contracts with Customers
  - Establishment and/or amortization of regulatory assets and liabilities
  - Assets held for sale
- Comparative presentation

The Notes to the Financial Statements have been prepared in conformity with GAAP. Accordingly, certain Notes are not prepared on the same basis as the financial statements presented herein.

Management has evaluated the impact of events occurring after December 31, 2024 up to February 19, 2025, the date that Georgia Power's GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 1, 2025 as it pertains to Georgia Power. These financial statements include all necessary adjustments and disclosures from these evaluations.

General

Southern Company is the parent company of three traditional electric operating companies, as well as Southern Power, Southern Company Gas, SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in three Southeastern states. Southern Power develops, constructs, acquires, owns, operates, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through natural gas distribution utilities, including Nicor Gas (Illinois), Atlanta Gas Light (Georgia), Virginia Natural Gas, and Chattanooga Gas (Tennessee). Southern Company Gas is also involved in several other complementary businesses including gas pipeline investments and gas marketing services. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services within the Southeast. Southern Holdings is an intermediate holding company subsidiary. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including Alabama Power's Plant Farley and Georgia Power's Plants Hatch and Vogtle. PowerSecure develops distributed energy and resilience solutions and deploys microgrids for commercial, industrial, governmental, and utility customers.

The Registrants' financial statements reflect investments in subsidiaries on a consolidated basis. Intercompany transactions have been eliminated in consolidation. The equity method is used for investments in entities in which a Registrant has significant influence but does not have control and for VIEs where a Registrant has an equity investment but is not the primary beneficiary. Southern Power has controlling ownership in certain legal entities for which the contractual provisions represent profit-sharing arrangements because the allocations of cash distributions and tax benefits are not based on fixed ownership percentages. For these arrangements, the noncontrolling interest is accounted for under a balance sheet approach utilizing the HLBV method. The HLBV method calculates each partner's share of income based on the change in net equity the partner can legally claim in an HLBV at the end of the period compared to the beginning of the period. See "Variable Interest Entities" herein and Note 7 for additional information.

The traditional electric operating companies, Southern Power, certain subsidiaries of Southern Company Gas, and certain other subsidiaries are subject to regulation by the FERC, and the traditional electric operating companies and the natural gas distribution utilities are also subject to regulation by their respective state PSCs or other applicable state regulatory agencies. As such, the respective financial statements of the applicable Registrants reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by relevant state PSCs or other applicable state regulatory agencies.

The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no impact on the Registrants' results of operations, financial position, or cash flows.

Recently Adopted Accounting Standards

In November 2023, the FASB issued ASU 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures* (ASU 2023-07), which requires entities to disclose significant segment expenses, other segment items, the title and position of the CODM, and information related to how the CODM assesses segment performance and allocates resources, among certain other required disclosures. Additionally, previous annual disclosures will be required in interim periods. The Registrants adopted ASU 2023-07 and applied the guidance retrospectively effective for the fiscal year beginning January 1, 2024. ASU 2023-07 will be applied retrospectively for the interim periods beginning January 1, 2025. See Note 16 for additional information and related disclosures.

Affiliate Transactions

The traditional electric operating companies, Southern Power, and Southern Company Gas have agreements with SCS under which certain of the following services are rendered to them at direct or allocated cost: general executive and advisory, general and design engineering, operations, purchasing, accounting, finance, treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, cellular tower space, and other services with respect to business and operations, construction management, and Southern Company power pool transactions. These costs are primarily included in other operations and maintenance expenses or capitalized to property, plant, and equipment. Costs for these services from SCS in 2024, 2023, and 2022 were as follows:

	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)		
2024	**$ 813**	**$ 1,197**	**$ 130**	**$ 93**	**$ 290**
2023	611	857	113	86	261
2022	549	762	115	86	262

Alabama Power and Georgia Power also have agreements with Southern Nuclear under which Southern Nuclear renders the following nuclear-related services at cost: general executive and advisory services; general operations, management, and technical services; administrative services including procurement, accounting, employee relations, systems, and procedures services; strategic planning and budgeting services; and other services with respect to business and operations. These costs are primarily included in other operations and maintenance expenses or capitalized to property, plant, and equipment. Costs for these services in

2024, 2023, and 2022 amounted to $260 million, $251 million, and $267 million, respectively, for Alabama Power and $835 million, $899 million, and $895 million, respectively, for Georgia Power.

Cost allocation methodologies used by SCS and Southern Nuclear prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

Alabama Power's and Georgia Power's power purchases from affiliates through the Southern Company power pool are included in purchased power, affiliates on their respective statements of income. Mississippi Power's and Southern Power's power purchases from affiliates through the Southern Company power pool are included in purchased power on their respective statements of income and were as follows:

	Mississippi Power	Southern Power
	(in millions)	
2024	**$ 8**	**$ 17**
2023	4	13
2022	4	29

Georgia Power has entered into several PPAs with Southern Power and one PPA with Mississippi Power for capacity and energy. Georgia Power's total expenses associated with these PPAs were $203 million, $143 million, and $151 million in 2024, 2023, and 2022, respectively. Southern Power's total revenues from all PPAs with Georgia Power, included in wholesale revenue affiliates on Southern Power's consolidated statements of income, were $149 million, $145 million, and $154 million for 2024, 2023, and 2022, respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $121 million, $116 million, and $116 million for 2024, 2023, and 2022, respectively. Mississippi Power's total revenues from its PPA with Georgia Power, which commenced in 2024, were $60 million in 2024 and are included in wholesale revenue affiliates on Mississippi Power's statements of income. See Notes 2 and 9 for additional information.

SCS (as agent for Alabama Power, Georgia Power, and Southern Power) and certain subsidiaries of Southern Company Gas have long-term interstate natural gas transportation agreements with SNG that are governed by the terms and conditions of SNG's natural gas tariff and are subject to FERC regulation. See Note 7 under "Southern Company Gas" for additional information. Transportation costs under these agreements in 2024, 2023, and 2022 were as follows:

	Alabama Power	Georgia Power	Southern Power	Southern Company Gas
		(in millions)		
2024	**$ 13**	**$ 103**	**$ 35**	**$ 28**
2023	12	101	34	28
2022	18	99	37	27

SCS, as agent for the traditional electric operating companies and Southern Power, has agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made under these agreements were immaterial for Alabama Power, Georgia Power, Mississippi Power, and Southern Power for all periods presented.

Alabama Power and Mississippi Power jointly own Plant Greene County. The companies have an agreement under which Alabama Power operates Plant Greene County and Mississippi Power reimburses Alabama Power for its proportionate share of non-fuel operations and maintenance expenses, which totaled $7 million, $5 million, and $6 million in 2024, 2023, and 2022, respectively. See Notes 2 and 5 under "Mississippi Power – Integrated Resource Plans" and "Joint Ownership Agreements," respectively, for additional information.

Alabama Power, Georgia Power, and Mississippi Power each have agreements with PowerSecure for equipment purchases and/or services related to utility infrastructure construction, distributed energy, and energy efficiency projects. Costs under these agreements were immaterial for all periods presented.

Southern Company Gas has a $74 million contract with the U.S. General Services Administration to increase energy efficiency at certain federal buildings across Georgia, which is expected to be completed in 2025. Southern Company Gas engaged PowerSecure to provide the majority of the construction services under the contract. During 2024, 2023, and 2022, Southern Company Gas paid $13 million, $29 million, and $10 million, respectively, to PowerSecure related to this agreement.

See Note 7 under "SEGCO" for information regarding Alabama Power's and Georgia Power's equity method investment in SEGCO and related affiliate purchased power costs, as well as Alabama Power's gas pipeline ownership agreement with SEGCO.

Southern Power has several agreements with SCS for transmission services, which are billed to Southern Power based on the Southern Company Open Access Transmission Tariff as filed with the FERC. Transmission services purchased by Southern Power from SCS totaled $25 million, $33 million, and $39 million for 2024, 2023, and 2022, respectively, and were charged to other operations and maintenance expenses in Southern Power's consolidated statements of income.

The traditional electric operating companies and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 14 under "Contingent Features" for additional information. Southern Power and the traditional electric operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity. See "Revenues – Southern Power" herein for additional information.

The traditional electric operating companies, Southern Power, and Southern Company Gas provide incidental services to and receive such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas neither provided nor received any material services to or from affiliates in any year presented.

Regulatory Assets and Liabilities

The traditional electric operating companies and the natural gas distribution utilities are subject to accounting requirements for the effects of rate regulation. Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent costs recovered that are expected to be incurred in the future or probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

In the event that a portion of a traditional electric operating company's or a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, such company would be required to write off to income or reclassify to AOCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional electric operating company or the natural gas distribution utility would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 2 for additional information including details of regulatory assets and liabilities reflected in the balance sheets for Southern Company, the traditional electric operating companies, and Southern Company Gas.

Revenues

The Registrants generate revenues from a variety of sources which are accounted for under various revenue accounting guidance, including revenue from contracts with customers, lease, derivative, and regulatory accounting. See Notes 4, 9, and 14 for additional information.

Traditional Electric Operating Companies

The majority of the revenues of the traditional electric operating companies are generated from contracts with retail electric customers. These revenues, generated from the integrated service to deliver electricity when and if called upon by the customer, are recognized as a single performance obligation satisfied over time, at a tariff rate, and as electricity is delivered to the customer during the month. Unbilled revenues related to retail sales are recognized for estimated deliveries of electricity not yet billed to these customers from the last bill date to the end of the accounting period. Retail rates may include provisions to adjust revenues for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are

adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered from or returned to customers, respectively, through adjustments to the billing factors. See Note 2 for additional information regarding regulatory matters of the traditional electric operating companies.

Wholesale capacity revenues from PPAs are recognized in amounts billable under the contract terms. Energy and other revenues are generally recognized as services are provided. The contracts for capacity and energy in a wholesale PPA have multiple performance obligations where the contract's total transaction price is allocated to each performance obligation based on the standalone selling price. The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, the traditional electric operating companies recognize revenue as the performance obligations are satisfied over time as electricity is delivered to the customer or as generation capacity is available to the customer.

For both retail and wholesale revenues, the traditional electric operating companies have elected to recognize revenue for their sales of electricity and capacity using the invoice practical expedient as they generally have a right to consideration in an amount that corresponds directly with the value to the customer of the performance completed to date and that may be invoiced. Payment for goods and services rendered is typically due in the subsequent month following satisfaction of the Registrants' performance obligation.

Southern Power

Southern Power sells capacity and energy at rates specified under contractual terms in long-term PPAs. These PPAs are accounted for as leases, normal sale derivatives, or contracts with customers. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Energy revenues are recognized in the period the energy is delivered. Capacity revenues from PPAs classified as sales-type leases are recognized by accounting for interest income on the net investment in the lease.

Southern Power's non-lease contracts commonly include capacity and energy which are considered separate performance obligations. In these contracts, the total transaction price is allocated to each performance obligation based on the standalone selling price. The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, Southern Power recognizes revenue as the performance obligations are satisfied over time, as electricity is delivered to the customer or as generation capacity is made available to the customer.

Southern Power generally has a right to consideration in an amount that corresponds directly with the value to the customer of the performance completed to date and may recognize revenue in the amount to which the entity has a right to invoice. Payment for goods and services rendered is typically due in the subsequent month following satisfaction of Southern Power's performance obligation.

When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

Southern Power may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains and losses on such contracts are recorded in wholesale revenues. See Note 14 and "Financial Instruments" herein for additional information.

Southern Company Gas

Southern Company Gas records revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory agencies of the natural gas distribution utilities.The majority of the revenues of Southern Company Gas are generated from contracts with natural gas distribution customers. Revenues from this integrated service to deliver gas when and if called upon by the customer are recognized as a single performance obligation satisfied over time and are recognized at a tariff rate as gas is delivered to the customer during the month.

Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers, revenues are based on actual deliveries through the end of the period.

Southern Company Gas has elected to recognize revenue for sales of gas using the invoice practical expedient as it generally has a right to consideration in an amount that corresponds directly with the value to the customer of the performance completed to date and that may be invoiced. Payment for goods and services rendered is typically due in the subsequent month following satisfaction of Southern Company Gas' performance obligation.

Gas Distribution Operations

Atlanta Gas Light operates in a deregulated natural gas market whereby Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. As required by the Georgia PSC, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial, and industrial end-use customer's distribution costs as well as for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable charge, which reflects the historic volumetric usage pattern for the entire residential class. With the exception of Atlanta Gas Light, the natural gas distribution utilities have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage.

The tariffs for the natural gas distribution utilities include provisions which allow for the recognition of certain revenues prior to the time such revenues are billed to customers. These provisions are referred to as alternative revenue programs and provide for the recognition of certain revenues prior to billing, as long as the amounts recognized will be collected from customers within 24 months of recognition. Revenue related to alternative revenue programs was $43 million, $20 million, and $(5) million in 2024, 2023, and 2022, respectively. These programs primarily consist of:

- *Weather normalization adjustments* – reduce customer bills when winter weather is colder than normal and increase customer bills when weather is warmer than normal and are included in the tariffs for Virginia Natural Gas and Chattanooga Gas;
- *Revenue normalization mechanisms* – mitigate the impact of conservation and declining customer usage and are contained in the tariffs for Virginia Natural Gas and Nicor Gas; and
- *Revenue true-up adjustment* – included within the provisions of the GRAM program in which Atlanta Gas Light participates as a short-term alternative to formal rate case filings, the revenue true-up feature provides for a positive (or negative) adjustment to record revenue in the amount of any variance to budgeted revenues, which are submitted and approved annually as a requirement of GRAM. Such adjustments are reflected in customer billings in a subsequent program year.

Gas Marketing Services

Gas marketing services is comprised of several choice-based natural gas marketers operating in various deregulated jurisdictions. While gas marketing services follows the same general approach to revenue recognition described for Southern Company Gas above, it recognizes revenues on certain 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts.

Concentration of Revenue

Southern Company, Alabama Power, Georgia Power, Mississippi Power (with the exception of its full requirements cost-based MRA electric tariffs described below), Southern Power, and Southern Company Gas each have a diversified base of customers and no single customer comprises 10% or more of each company's revenues.

Mississippi Power provides service under long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under requirements cost-based MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 13.9% of Mississippi Power's total operating revenues in 2024.

Fuel Costs

Fuel costs for the traditional electric operating companies and Southern Power are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. For Alabama Power and Georgia Power, fuel expense also includes the amortization of the cost of nuclear fuel. For the traditional electric operating companies, fuel costs also include gains and/or losses from fuel-hedging programs as approved by their respective state PSCs.

Cost of Natural Gas

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, Southern Company Gas charges its utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the applicable state regulatory agencies. Under these mechanisms, all prudently-incurred natural gas costs are passed through to customers without markup, subject to regulatory review. Southern Company Gas defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period such that no operating income is recognized related to these costs. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred and accrued natural gas costs are included in the balance sheets as regulatory assets and regulatory liabilities, respectively.

Southern Company Gas' gas marketing services' customers are charged for actual or estimated natural gas consumed. Within cost of natural gas, Southern Company Gas also includes costs of lost and unaccounted for gas and gains and losses associated with certain derivatives.

Income Taxes

The Registrants use the liability method of accounting for deferred income taxes and provide deferred income taxes for all significant income tax temporary differences. In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies are amortized over the average life of the related property, with such amortization normally applied as a credit to reduce depreciation and amortization in the statements of income. Southern Power's and the natural gas distribution utilities' deferred federal ITCs, as well as certain state ITCs for Nicor Gas, are amortized to income tax expense over the life of the respective asset.

Under current tax law, certain projects at Southern Power related to the construction of renewable facilities are eligible for federal ITCs. Southern Power estimates eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of the purchase price to assets has been finalized. Southern Power applies the deferred method to ITCs, whereby the ITCs are recorded as a deferred credit and amortized to income tax expense over the life of the respective asset. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, which, together with the deferred credit, results in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. State ITCs are recognized as an income tax benefit in the period in which the credits are generated. In addition, certain projects are eligible for federal and state PTCs, which are recognized as an income tax benefit based on KWH production.

Federal ITCs and PTCs, as well as state ITCs and other state tax credits available to reduce income taxes payable, were not fully utilized in 2024 and will be carried forward and utilized in future years. In addition, Southern Company is expected to have various state net operating loss (NOL) carryforwards for certain of its subsidiaries, including Mississippi Power and Southern Power, which would result in income tax benefits in the future, if utilized. See Note 10 under "Deferred Tax Assets and Liabilities – Tax Credit Carryforwards" and " – Net Operating Loss Carryforwards" for additional information.

In April 2024, the IRS issued final regulations related to the transferability of certain tax credits under the IRA. Southern Company and certain subsidiaries have tax credits that are eligible to be transferred at a discount to the generated credit value. The discount will be recorded as a reduction in tax credits recognized in the financial statements. See Note 10 under "Current and Deferred Income Taxes" for additional information.

Under current tax law, Georgia Power is eligible to generate advanced nuclear PTCs for Plant Vogtle Units 3 and 4, which are recognized as an income tax benefit based on KWH production and are eligible to be transferred. Pursuant to the Vogtle Joint Ownership Agreements (as defined in Note 2 under "Georgia Power – Nuclear Construction – Cost and Schedule"), Georgia

Power is purchasing advanced nuclear PTCs for Plant Vogtle Units 3 and 4 from the other Vogtle Owners. The gain recognized on the purchase of the joint owner PTCs is recognized as an income tax benefit.

The Registrants recognize tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 10 under "Unrecognized Tax Benefits" for additional information.

Other Taxes

Taxes imposed on and collected from customers on behalf of governmental agencies are presented net on the Registrants' statements of income and are excluded from the transaction price in determining the revenue related to contracts with a customer.

Southern Company Gas is taxed on its gas revenues by various governmental authorities, but is allowed to recover these taxes from its customers. Revenue taxes imposed on the natural gas distribution utilities are recorded at the amount charged to customers, which may include a small administrative fee, as operating revenues, and the related taxes imposed on Southern Company Gas are recorded as operating expenses on the statements of income. Revenue taxes included in operating expenses were $112 million, $129 million, and $158 million in 2024, 2023, and 2022, respectively.

Allowance for Funds Used During Construction and Interest Capitalized

The traditional electric operating companies and the natural gas distribution utilities record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the asset through a higher rate base and higher depreciation. The equity component of AFUDC is not taxable.

Interest related to financing the construction of new facilities at Southern Power and new facilities not included in the traditional electric operating companies' and Southern Company Gas' regulated rates is capitalized in accordance with standard interest capitalization requirements.

Total AFUDC and interest capitalized for the applicable Registrants in 2024, 2023, and 2022 was as follows:

	Southern Company	Alabama Power	Georgia Power(*)	Southern Power	Southern Company Gas
			(in millions)		
2024	**$ 339**	**$ 76**	**$ 209**	**$ 7**	**$ 47**
2023	400	109	251	3	37
2022	327	90	213	—	24

* See Note 2 under "Georgia Power – Nuclear Construction" for information on the inclusion of a portion of construction costs related to Plant Vogtle Units 3 and 4 in Georgia Power's rate base through each unit's respective in-service date.

The average AFUDC composite rates for 2024, 2023, and 2022 for the traditional electric operating companies and the natural gas distribution utilities were as follows:

	2024	2023	2022
Alabama Power	**8.1 %**	8.1 %	7.9 %
Georgia Power[(a)]	**7.7 %**	7.6 %	7.3 %
Mississippi Power[(b)]	**— %**	— %	5.3 %
Southern Company Gas:			
Atlanta Gas Light	**7.7 %**	7.4 %	7.6 %
Chattanooga Gas	**7.1 %**	7.1 %	7.1 %
Nicor Gas	**5.6 %**	4.6 %	2.0 %

(a) Excludes AFUDC related to the construction of Plant Vogtle Units 3 and 4 in 2022 and 2023 and Plant Vogtle Unit 4 in 2024. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

(b) Mississippi Power's AFUDC was immaterial in 2024 and 2023.

Impairment of Long-Lived Assets

The Registrants evaluate long-lived assets for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance, a sales transaction price that is less than the asset group's carrying amount, or an estimate of undiscounted future cash flows attributable to the asset group, as compared with the carrying amount of the assets. If an impairment has occurred, the amount of the impairment loss recognized is determined by

either the amount of regulatory disallowance or by the amount the carrying amount exceeds the estimated fair value of the assets. For assets identified as held for sale, the carrying amount is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

In the third quarter 2024, Alabama Power discontinued the development of a multi-use commercial facility. Given the decision to discontinue commercial development, Alabama Power performed an impairment test using a comparative market analysis and determined the carrying amount of the asset exceeded its fair value, net of selling costs. This resulted in a pre-tax impairment loss of $36 million ($27 million after tax) reflected in other operations and maintenance on the statements of income.

See Note 15 under "Southern Company Gas" for information regarding impairment charges recorded during 2022.

Goodwill and Other Intangible Assets

Goodwill and other intangible assets not subject to amortization are evaluated for impairment on an annual basis and when events or changes in circumstances necessitate an evaluation for impairment. Other intangible assets subject to amortization are evaluated for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable.

Southern Power's intangible assets consist primarily of certain PPAs acquired, which are amortized over the term of the respective PPA. Southern Company Gas' goodwill and other intangible assets primarily relate to its 2016 acquisition by Southern Company. In addition to these items, Southern Company's goodwill and other intangible assets also relate to its 2016 acquisition of PowerSecure.

For its 2024 annual goodwill impairment test, Southern Company Gas management performed the quantitative assessment, which resulted in the fair value of its reporting units with goodwill exceeding their carrying amounts. For its 2023 and 2022 annual goodwill impairment tests, Southern Company Gas management performed the qualitative assessment and determined that it was more likely than not that the fair value of its reporting units with goodwill exceeded their carrying amounts, and therefore no quantitative assessment was required.

For its 2024 annual goodwill impairment test, PowerSecure management performed the qualitative assessment and determined that it was more likely than not that the fair value of PowerSecure exceeded its carrying amount, and therefore no quantitative assessment was required. For its 2023 annual goodwill impairment test, PowerSecure management performed the quantitative assessment, which resulted in the fair value of PowerSecure exceeding its carrying amount. For its 2022 annual goodwill impairment test, PowerSecure management performed the quantitative assessment, which resulted in the fair value of PowerSecure being lower than its carrying amount. The fair value was estimated using a discounted cash flow analysis. The decline in fair value primarily resulted from declining macroeconomic conditions, reducing sales growth and estimated cash flows. As a result, a goodwill impairment of $119 million was recorded in the fourth quarter 2022.

At December 31, 2024 and 2023, goodwill was as follows:

	At December 31, 2024	At December 31, 2023
	(in millions)	
Southern Company	**$ 5,161**	$ 5,161
Southern Company Gas:		
Gas distribution operations	**$ 4,034**	$ 4,034
Gas marketing services	**981**	981
Southern Company Gas total	**$ 5,015**	$ 5,015

At December 31, 2024 and 2023, other intangible assets were as follows:

	At December 31, 2024			At December 31, 2023		
	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
	(in millions)			*(in millions)*		
Southern Company						
Subject to amortization:						
Customer relationships	**$ 212**	**$ (182)**	**$ 30**	$ 212	$ (172)	$ 40
Trade names	**64**	**(59)**	**5**	64	(53)	11
PPA fair value adjustments	**390**	**(168)**	**222**	390	(148)	242
Other	**3**	**(3)**	**—**	3	(3)	—
Total subject to amortization	**$ 669**	**$ (412)**	**$ 257**	$ 669	$ (376)	$ 293
Not subject to amortization:						
FCC licenses	**75**	**—**	**75**	75	—	75
Total other intangible assets	**$ 744**	**$ (412)**	**$ 332**	$ 744	$ (376)	$ 368
Southern Power(*)						
PPA fair value adjustments	**$ 390**	**$ (168)**	**$ 222**	$ 390	$ (148)	$ 242
Southern Company Gas(*)						
Gas marketing services						
Customer relationships	**$ 156**	**$ (150)**	**$ 6**	$ 156	$ (145)	$ 11
Trade names	**26**	**(23)**	**3**	26	(21)	5
Total other intangible assets	**$ 182**	**$ (173)**	**$ 9**	$ 182	$ (166)	$ 16

* All subject to amortization.

Amortization associated with other intangible assets in 2024, 2023, and 2022 was as follows:

	2024	2023	2022
		(in millions)	
Southern Company[a]	**$ 35**	$ 38	$ 39
Southern Power[b]	**20**	20	20
Southern Company Gas			
Gas marketing services	**7**	10	11

(a) Includes $20 million annually recorded as a reduction to operating revenues.

(b) Recorded as a reduction to operating revenues.

At December 31, 2024, the estimated amortization associated with other intangible assets for the next five years is as follows:

	2025	2026	2027	2028	2029
			(in millions)		
Southern Company	$ 32	$ 27	$ 23	$ 23	$ 23
Southern Power	20	20	20	20	19
Southern Company Gas					
Gas marketing services	6	3	—	—	—

Acquisition Accounting

At the time of an acquisition, management will assess whether acquired assets and activities meet the definition of a business. Acquisitions that meet the definition of a business are accounted for under the acquisition method, and operating results from the date of acquisition are included in the acquiring entity's financial statements. Identifiable assets acquired, liabilities assumed, and any noncontrolling interests (including any intangible assets) are recognized and measured at fair value. Assets acquired that do not meet the definition of a business are accounted for as an asset acquisition. The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. See Note 15 for additional information, including recent and proposed acquisitions.

Determining the fair value of assets acquired and liabilities assumed requires management judgment and management may engage independent valuation experts to assist in this process. Fair values are determined by using market participant assumptions and typically include the timing and amounts of future cash flows, incurred construction costs, the nature of acquired contracts, discount rates, power market prices, and expected asset lives. For potential or successful acquisitions that meet the definition of a business, any due diligence or transaction costs incurred are expensed as incurred. If the acquisition is accounted for as an asset acquisition, direct and incremental transaction costs can be capitalized as a component of the cost of the assets acquired.

Historically, any contingent consideration relates to fixed amounts due to the seller once an acquired construction project is placed in service. For contingent consideration with variable payments, management fair values the arrangement with any changes recorded in the statements of income. See Note 13 for additional fair value information.

Development Costs

For Southern Power, development costs are capitalized once a project is probable of completion, primarily based on a review of its economics and operational feasibility, as well as the status of power off-take agreements and regulatory approvals, if applicable. Southern Power's capitalized development costs are included in CWIP on the balance sheets. All of Southern Power's development costs incurred prior to the determination that a project is probable of completion are expensed as incurred and included in other operations and maintenance expense in the statements of income. If it is determined that a project is no longer probable of completion, any of Southern Power's capitalized development costs are expensed and included in other operations and maintenance expense in the statements of income.

Long-Term Service Agreements

The traditional electric operating companies and Southern Power have entered into LTSAs for the purpose of securing maintenance support for certain of their generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs for the performance of any planned inspections or unplanned capital maintenance are recorded in the statements of cash flows as investing activities. Receipts of major parts into materials and supplies inventory prior to planned inspections are treated as noncash transactions in the statements of cash flows. Any payments made prior to the work being performed are recorded as prepayments in other current assets and non-current assets on the balance sheets or reduce existing payables for LTSA-related work already completed. At the time work is performed, an appropriate amount is accrued for future payments or transferred from the prepayment and recorded as property, plant, and equipment or expensed.

Transmission Receivables/Prepayments

As a result of Southern Power's acquisition and construction of generating facilities, Southern Power has transmission receivables and/or prepayments representing the portion of interconnection network and transmission upgrades that will be reimbursed to Southern Power. Upon completion of the related project, transmission costs are generally reimbursed by the interconnection provider within a five-year period and the receivable/prepayments are reduced as payments or services are received.

Cash, Cash Equivalents, and Restricted Cash

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets that total to the amount shown in the statements of cash flows for the applicable Registrants:

	Southern Company	Alabama Power	Georgia Power	Southern Power	Southern Company Gas
			(in millions)		
At December 31, 2024					
Cash and cash equivalents	**$ 1,070**	**$ 585**	**$ 97**	**$ 159**	**$ 43**
Restricted cash[(a)]:					
Other current assets	**31**	**—**	**21**	**9**	**1**
Total cash, cash equivalents, and restricted cash[(b)]	**$ 1,101**	**$ 585**	**$ 118**	**$ 168**	**$ 44**
At December 31, 2023					
Cash and cash equivalents	$ 748	$ 324	$ 9	$ 124	$ 33
Restricted cash[(a)]:					
Other current assets	141	85	37	17	2
Other deferred charges and assets	31	—	29	3	—
Total cash, cash equivalents, and restricted cash[(b)]	$ 921	$ 409	$ 75	$ 144	$ 35

(a) For Alabama Power and Georgia Power, reflects proceeds from the issuance of solid waste disposal facility revenue bonds in 2023 and 2022, respectively. See Note 8 under "Long-term Debt" for additional information. For Southern Power, reflects $9 million and $17 million at December 31, 2024 and 2023, respectively, resulting from an arbitration award held to fund future replacement costs and $3 million at December 31, 2023 held to fund estimated construction completion costs at the Deuel Harvest wind facility. For Southern Company Gas, reflects collateral for workers' compensation, life insurance, and long-term disability insurance.

(b) Total may not add due to rounding.

Storm Damage and Reliability Reserves

In accordance with their respective state PSC orders, the traditional electric operating companies accrue certain amounts annually related to storm damage recovery. Each traditional electric operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution facilities and, for Mississippi Power, the cost of uninsured damages to its generation facilities and other property. Alabama Power and Mississippi Power also have authority from the Alabama PSC and the Mississippi PSC, respectively, to accrue certain additional amounts as circumstances warrant. Alabama Power recorded an additional accrual of $21 million in 2024, which is included in the table below.

Storm damage reserve activity for the traditional electric operating companies during 2023 and 2024 was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power
			(in millions)	
Balance at December 31, 2022	$ 216	$ 97	$ 83	$ 36
Accrual	61	18	31	12
Weather-related damages	(211)	(39)	(168)	(4)
Balance at December 31, 2023	$ 66	$ 76	$ (54)	$ 44
Accrual	**79**	**34**	**31**	**14**
Weather-related damages	**(850)**	**(40)**	**(804)**	**(6)**
Balance at December 31, 2024	**$ (705)**	**$ 70**	**$ (827)**	**$ 52**

The traditional electric operating companies accrued the following amounts related to storm damage recovery in 2022:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power
		(in millions)		
2022	$ 239	$ 19	$ 213	$ 7

In 2022, costs for weather-related damages charged against storm damage reserves totaled $24 million and $82 million for Alabama Power and Georgia Power, respectively, and were immaterial for Mississippi Power.

See Note 2 under "Alabama Power – Rate NDR," "Georgia Power – Storm Damage Recovery," and "Mississippi Power – System Restoration Rider" for additional information regarding each company's storm damage reserve.

During 2022, the Alabama PSC and the Mississippi PSC authorized Alabama Power and Mississippi Power, respectively, to make accruals to a reliability reserve if certain conditions are met. During 2024, 2023, and 2022, Alabama Power and Mississippi Power accrued the following amounts to their reliability reserves:

	Southern Company	Alabama Power	Mississippi Power
		(in millions)	
2024	**$ 84**	**$ 63**	**$ 21**
2023	63	52	11
2022	191	166	25

See Note 2 under "Alabama Power – Reliability Reserve Accounting Order" and "Mississippi Power – Reliability Reserve Accounting Order" for additional information.

Materials and Supplies

Materials and supplies for the traditional electric operating companies generally includes the average cost of transmission, distribution, and generating plant materials. Materials and supplies for Southern Company Gas generally includes the average cost of propane gas inventory, liquefied natural gas inventory, fleet fuel, and other materials and supplies. Materials and supplies for Southern Power generally includes the average cost of generating plant materials.

Materials are recorded to inventory when purchased and then expensed or capitalized to property, plant, and equipment, as appropriate, at weighted average cost when installed. In addition, certain major parts are recorded as inventory when acquired and then capitalized at cost when installed to property, plant, and equipment.

Fuel Inventory

Fuel inventory for the traditional electric operating companies includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel inventory for Southern Power, which is included in other current assets, includes the average cost of oil, natural gas, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted

average cost, as used. Emissions allowances granted by the EPA are included in inventory at zero cost. The traditional electric operating companies recover fuel expense through fuel cost recovery rates approved by each state PSC or, for wholesale rates, the FERC.

Natural Gas for Sale

With the exception of Nicor Gas, Southern Company Gas records natural gas inventories on a weighted average cost of gas basis. In Georgia's deregulated, competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. On a monthly basis, Atlanta Gas Light assigns to Marketers the majority of the pipeline storage services that it has under contract, along with a corresponding amount of inventory. Atlanta Gas Light retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand.

Nicor Gas' natural gas inventory is carried at cost on a LIFO basis. Inventory decrements occurring during the year that are restored prior to year-end are charged to cost of natural gas at the estimated annual replacement cost. Inventory decrements that are not restored prior to year-end are charged to cost of natural gas at the actual LIFO cost of the inventory layers liquidated. The cost of natural gas, including inventory costs, is recovered from customers under a purchased gas recovery mechanism adjusted for differences between actual costs and amounts billed; therefore, LIFO liquidations have no impact on Southern Company's or Southern Company Gas' net income. At December 31, 2024, the Nicor Gas LIFO inventory balance was $188 million. Based on the average cost of gas purchased in December 2024, the estimated replacement cost of Nicor Gas' inventory at December 31, 2024 was $326 million.

Provision for Uncollectible Accounts

The customers of the traditional electric operating companies and the natural gas distribution utilities are billed monthly. For the majority of receivables, a provision for uncollectible accounts is established based on historical collection experience and other factors. For the remaining receivables, if the company is aware of a specific customer's inability to pay, a provision for uncollectible accounts is recorded to reduce the receivable balance to the amount reasonably expected to be collected. If circumstances change, the estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect this estimate include, but are not limited to, customer credit issues, customer deposits, and general economic conditions. Customers' accounts are written off once they are deemed to be uncollectible. For all periods presented, uncollectible accounts averaged less than 1% of revenues for each Registrant.

Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year.

Concentration of Credit Risk

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 14 Marketers in Georgia (including SouthStar). The credit risk exposure to the Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain credit security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Financial Instruments

The traditional electric operating companies and Southern Power use derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and occasionally foreign currency exchange rates. Southern Company Gas uses derivative financial instruments to limit exposure to fluctuations in natural gas prices, weather, and

interest rates. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 13 for additional information regarding fair value. Substantially all of the traditional electric operating companies', Southern Power's,

and Southern Company Gas' bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs result in the deferral of related gains and losses in AOCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 14 for additional information regarding derivatives.

The Registrants offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. The Registrants had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2024.

The Registrants are exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The Registrants have established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate their exposure to counterparty credit risk.

Southern Company Gas

Southern Company Gas enters into weather derivative contracts as economic hedges of natural gas revenues in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in natural gas revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are also reflected in natural gas revenues in the statements of income.

Southern Company Gas enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. NYMEX futures and OTC contracts are used to capture the price differential or spread between the locations served by the capacity to substantially protect the natural gas revenues that will ultimately be realized when the physical flow of natural gas between delivery points occurs. These contracts generally meet the definition of derivatives and are carried at fair value on the balance sheets, with changes in fair value included in earnings in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage, and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis utilized for the derivatives used to mitigate the natural gas price risk associated with the storage and transportation portfolio. Monthly demand charges are incurred for the contracted storage and transportation capacity and payments associated with asset management agreements, and these demand charges and payments are recognized on the statements of income in the period they are incurred. This difference in accounting methods can result in volatility in reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income attributable to the Registrant, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income. Comprehensive income also consists of certain changes in pension and other postretirement benefit plans for Southern Company, Southern Power, and Southern Company Gas.

AOCI (loss) balances, net of tax effects, for Southern Company, Southern Power, and Southern Company Gas were as follows:

	Qualifying Hedges	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)(*)
		(in millions)	
Southern Company			
Balance at December 31, 2021	$ (162)	$ (76)	$ (237)
Current period change	13	58	71
Balance at December 31, 2022	(149)	(18)	(167)
Current period change	28	(38)	(10)
Balance at December 31, 2023	(121)	(56)	(177)
Current period change	**75**	**24**	**99**
Balance at December 31, 2024	**$ (46)**	**$ (32)**	**$ (78)**
Southern Power			
Balance at December 31, 2021	$ 1	$ (29)	$ (27)
Current period change	(10)	20	10
Balance at December 31, 2022	(9)	(9)	(18)
Current period change	8	(7)	1
Balance at December 31, 2023	(1)	(16)	(17)
Current period change	**8**	**7**	**15**
Balance at December 31, 2024	**$ 7**	**$ (9)**	**$ (2)**
Southern Company Gas			
Balance at December 31, 2021	$ (14)	$ 38	$ 24
Current period change	(11)	18	7
Balance at December 31, 2022	(25)	56	31
Current period change	1	(16)	(15)
Balance at December 31, 2023	(24)	40	16
Current period change	**21**	**11**	**32**
Balance at December 31, 2024	**$ (3)**	**$ 51**	**$ 48**

* May not add due to rounding.

Variable Interest Entities

The Registrants may hold ownership interests in a number of business ventures with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE. The primary beneficiary of a VIE is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the VIE. See Note 7 for additional information regarding VIEs.

2. REGULATORY MATTERS

Regulatory Assets and Liabilities

Details of regulatory assets and (liabilities) reflected in the balance sheets at December 31, 2024 and 2023 are provided in the following tables:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
At December 31, 2024					
AROs(*)	**$ 5,810**	**$ 1,906**	**$ 3,658**	**$ 248**	**$ —**
Retiree benefit plans(*)	**2,605**	**680**	**892**	**134**	**44**
Remaining net book value of retired assets	**1,198**	**454**	**729**	**15**	**—**
Deferred income tax charges	**927**	**264**	**634**	**27**	**—**
Storm damage	**859**	**—**	**827**	**32**	**—**
Deferred depreciation	**535**	**286**	**249**	**—**	**—**
Environmental remediation(*)	**249**	**—**	**16**	**—**	**233**
Vacation pay(*)	**224**	**85**	**112**	**12**	**15**
Loss on reacquired debt	**219**	**32**	**183**	**4**	**—**
Software and cloud computing costs	**200**	**76**	**116**	**4**	**4**
Under recovered regulatory clause revenues	**167**	**119**	**—**	**17**	**31**
Regulatory clauses	**162**	**82**	**—**	**—**	**80**
Nuclear outage	**92**	**39**	**53**	**—**	**—**
Fuel-hedging (realized and unrealized) losses	**69**	**23**	**29**	**17**	**—**
Qualifying repairs of natural gas distribution systems	**53**	**—**	**—**	**—**	**53**
Long-term debt fair value adjustment	**52**	**—**	**—**	**—**	**52**
Plant Daniel Units 3 and 4	**23**	**—**	**—**	**23**	**—**
Other regulatory assets	**184**	**42**	**40**	**30**	**72**
Deferred income tax credits	**(4,536)**	**(1,398)**	**(2,149)**	**(219)**	**(755)**
Other cost of removal obligations	**(1,176)**	**24**	**816**	**(170)**	**(1,846)**
Over recovered regulatory clause revenues	**(285)**	**(29)**	**(52)**	**—**	**(204)**
Reliability reserves	**(188)**	**(131)**	**—**	**(57)**	**—**
Storm/property damage reserves	**(122)**	**(70)**	**—**	**(52)**	**—**
Nuclear fuel disposal cost recovery	**(100)**	**(100)**	**—**	**—**	**—**
Other regulatory liabilities	**(180)**	**(28)**	**(14)**	**(6)**	**(31)**
Total regulatory assets (liabilities), net	**$ 7,041**	**$ 2,356**	**$ 6,139**	**$ 59**	**$ (2,252)**
At December 31, 2023					
AROs(*)	$ 5,733	$ 1,936	$ 3,505	$ 247	$ —
Retiree benefit plans(*)	3,011	815	976	140	146
Remaining net book value of retired assets	1,357	499	841	17	—
Deferred income tax charges	897	262	605	28	—
Under recovered regulatory clause revenues	413	381	—	12	20
Fuel-hedging (realized and unrealized) losses	270	100	121	49	—
Deferred depreciation	270	143	127	—	—
Environmental remediation(*)	255	—	20	—	235
Loss on reacquired debt	238	35	197	5	1
Vacation pay(*)	217	83	107	11	16
Software and cloud computing costs	150	59	84	2	5
Regulatory clauses	140	112	—	—	28
Storm damage	92	—	54	38	—
Nuclear outage	83	50	33	—	—
Long-term debt fair value adjustment	60	—	—	—	60
Qualifying repairs of natural gas distribution systems	40	—	—	—	40
Plant Daniel Units 3 and 4	25	—	—	25	—
Other regulatory assets	189	39	33	25	93
Deferred income tax credits	(4,686)	(1,506)	(2,161)	(241)	(759)
Other cost of removal obligations	(1,312)	28	617	(186)	(1,771)
Over recovered regulatory clause revenues	(287)	(3)	(46)	—	(238)
Reliability reserves	(179)	(143)	—	(36)	—
Storm/property damage reserves	(120)	(76)	—	(44)	—
Other regulatory liabilities	(333)	(94)	(23)	(2)	(101)
Total regulatory assets (liabilities), net	$ 6,523	$ 2,720	$ 5,090	$ 90	$ (2,225)

* Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

Unless otherwise noted, the following recovery and amortization periods for these regulatory assets and (liabilities) have been approved by the respective state PSC or regulatory agency:

AROs and other cost of removal obligations – Generally recorded over the related property lives, which may range up to 64 years for Alabama Power, 54 years for Georgia Power, 67 years for Mississippi Power, and 85 years for Southern Company Gas. AROs and other cost of removal obligations are settled and trued up following completion of the related activities. Alabama Power is recovering CCR ARO expenditures over a 38-year period ending in 2054 through Rate CNP Compliance. Effective January 1, 2023, Georgia Power is recovering CCR ARO expenditures over four-year periods through its ECCR tariff. Prior to 2023, expenditures were recovered over three-year periods. See "Georgia Power – Rate Plans" herein and Note 6 for additional information.

Retiree benefit plans – Recovered and amortized over the average remaining service period, which may range up to 14 years for Alabama Power, Georgia Power, Mississippi Power, and Southern Company Gas. Southern Company's balances also include amounts at SCS and Southern Nuclear that are allocated to the applicable regulated utilities. See Note 11 for additional information.

Remaining net book value of retired assets –

Alabama Power: Primarily represents the net book value of Plant Gorgas Unit 10 ($419 million at December 31, 2024) being amortized over 13 years (through 2037) and Plant Barry Unit 4 ($35 million at December 31, 2024) being amortized over 10 years (through 2034). See "Alabama Power – Environmental Accounting Order" herein for additional information.

Georgia Power: Net book values of Plant Wansley Units 1 and 2 and Plant Hammond Units 3 and 4 (totaling $418 million and $302 million, respectively, at December 31, 2024) are being amortized over remaining periods between one and 11 years (between 2025 and 2035). Balance also includes unusable materials and supplies inventories, for which the Georgia PSC will determine a recovery period in a future base rate case.

Mississippi Power: Represents net book value of certain environmental compliance assets at Plant Watson and Plant Greene County. The retail portion is being amortized over 10 years (through 2033) and the wholesale portion is being amortized over 10 years (through 2034). See "Mississippi Power – Environmental Compliance Overview Plan" herein for additional information.

Deferred income tax charges and credits – Charges are recovered and credits are primarily amortized over the related property lives, which may range up to 64 years for Alabama Power, 54 years for Georgia Power, 67 years for Mississippi Power, and 85 years for Southern Company Gas. See Note 10 for additional information. These accounts include certain deferred income tax assets and liabilities not subject to normalization, as described further below:

Alabama Power: Related amounts at December 31, 2024 include excess federal deferred income tax liabilities that are available for the benefit of customers in 2025, as discussed under "Alabama Power – Excess Accumulated Deferred Income Tax Accounting Order" herein. Remaining amounts are being recovered and amortized ratably over the related property lives.

Georgia Power: Related amounts at December 31, 2024 include $135 million of deferred income tax assets related to construction costs for Plant Vogtle Units 3 and 4 being recovered over 10 years (through 2034) and $102 million of excess state deferred income tax liabilities that will be returned to customers in 2025. See "Georgia Power – Nuclear Construction – Regulatory Matters" herein for additional information on recovery of costs related to Plant Vogtle Units 3 and 4.

Southern Company Gas: Related amounts at December 31, 2024 include $24 million of deferred income tax liabilities being amortized over periods generally not exceeding five years, primarily related to excess state deferred income tax liabilities. See "Southern Company Gas – Rate Proceedings" herein for additional information.

Storm damage – See "Georgia Power – Storm Damage Recovery" herein and Note 1 under "Storm Damage and Reliability Reserves" for additional information. Mississippi Power's balance represents deferred storm costs associated with Hurricanes Ida and Zeta being recovered through PEP over seven years (through 2029).

Deferred depreciation –

Alabama Power: Represents deferred depreciation for Plant Barry Unit 5 ($114 million at December 31, 2024) and Plant Barry common coal assets ($48 million at December 31, 2024) to be amortized until 2036 beginning when Plant Barry Unit 5 is retired and Plant Gaston Unit 5 coal assets ($124 million at December 31, 2024) to be amortized until 2039 beginning when the assets are retired.

Georgia Power: Represents deferred depreciation for Plant Scherer Units 1 through 3 ($139 million at December 31, 2024) to be amortized over six years beginning in 2029 and Plant Bowen Units 1 and 2 ($80 million at December 31, 2024) to be amortized over four years beginning in 2031, both as approved under Georgia Power's 2022 ARP, and Plant Vogtle Unit 3 and common facilities ($29 million at December 31, 2024) being amortized over 10 years (through 2034). See "Georgia Power – Nuclear Construction – Regulatory Matters" herein for additional information on recovery of costs related to Plant Vogtle Units 3 and 4.

Environmental remediation – Effective January 1, 2023, Georgia Power is recovering $5 million annually for environmental remediation under the 2022 ARP. Southern Company Gas' costs are recovered through environmental cost recovery mechanisms when the remediation work is performed. See Note 3 under "Environmental Remediation" for additional information.

Vacation pay – Recorded as earned by employees and recovered as paid, generally within one year. Includes both vacation and banked holiday pay, if applicable.

Loss on reacquired debt – Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue. At December 31, 2024, the remaining amortization periods do not exceed 23 years for Alabama Power, 28 years for Georgia Power, 17 years for Mississippi Power, and three years for Southern Company Gas.

Software and cloud computing costs – Represents certain deferred operations and maintenance costs associated with software and cloud computing projects. For Alabama Power, costs are amortized ratably over the life of the related software, which ranges up to 10 years (through 2034). For Georgia Power, costs incurred through 2022 are being amortized over five years (through 2027), and the recovery period for costs incurred after 2022 will be determined in its next base rate case. For Mississippi Power, the recovery period will be determined in Mississippi Power's annual PEP filing process following the completion of the projects and is expected to begin no earlier than 2026. For Southern Company Gas, costs are being amortized ratably over the life of the related software, which ranges up to 10 years (through 2034).

Under and over recovered regulatory clause revenues –

Alabama Power: Balances are recorded monthly and expected to be recovered over periods of up to six years, with the majority expected to be recovered within one year. See "Alabama Power – Rate CNP PPA," " – Rate CNP Compliance," and " – Rate ECR" herein for additional information.

Georgia Power: Balances are recorded monthly and expected to be recovered or returned within two years. See "Georgia Power – Rate Plans" herein for additional information.

Mississippi Power: At December 31, 2024, $17 million is expected to be recovered through various rate recovery mechanisms over a period to be determined in future rate filings. See "Mississippi Power – Ad Valorem Tax Adjustment" herein for additional information.

Southern Company Gas: Balances are recorded and recovered or amortized over periods generally not exceeding five years. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities have various other cost recovery mechanisms for the recovery of costs, including those related to infrastructure replacement programs.

Regulatory clauses –

Alabama Power: Effective January 1, 2023, balance is being amortized through Rate RSE over a five-year period ending in 2027.

Southern Company Gas: Represents amounts related to Nicor Gas' volume balancing adjustment rider expected to be recovered over a period of less than two years.

Nuclear outage – Costs are deferred to a regulatory asset when incurred and amortized over a subsequent period of 18 months for Alabama Power and up to 24 months for Georgia Power. See Note 5 for additional information.

Fuel-hedging (realized and unrealized) losses and gains – Assets and liabilities are recorded over the life of the underlying hedged purchase contracts. Upon final settlement, actual costs incurred are recovered through the applicable traditional electric operating company's fuel cost recovery mechanism. Purchase contracts generally do not exceed three and a half years for Alabama Power, three years for Georgia Power, and four years for Mississippi Power. Immaterial amounts for fuel-hedging gains at December 31, 2024 and 2023 are included in other regulatory liabilities.

Qualifying repairs of natural gas distribution systems – Represents deferred costs of certain repairs at Atlanta Gas Light being amortized over 20 years.

Long-term debt fair value adjustment – Recovered over the remaining lives of the original debt issuances at acquisition, which range up to 14 years at December 31, 2024.

Plant Daniel Units 3 and 4 – Represents the difference between Mississippi Power's revenue requirement for Plant Daniel Units 3 and 4 under purchase accounting and operating lease accounting. At December 31, 2024, consists of the $16 million retail portion being amortized through 2039 over the remaining life of the related property and the $8 million wholesale portion being amortized over 10 years (through 2034).

Other regulatory assets – Comprised of numerous immaterial components with remaining amortization periods at December 31, 2024 generally not exceeding 19 years for Alabama Power, 10 years for Georgia Power, 10 years for Mississippi Power, and 15 years for Southern Company Gas.

Reliability reserves and storm/property damage reserves – Utilized as related expenses are incurred. See "Alabama Power – Rate NDR" and " – Reliability Reserve Accounting Order," "Georgia Power – Storm Damage Recovery," and "Mississippi Power – System Restoration Rider" and " – Reliability Reserve Accounting Order" herein and Note 1 under "Storm Damage and Reliability Reserves" for additional information.

Nuclear fuel disposal cost recovery – Represents award resulting from litigation related to nuclear fuel disposal costs. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Other regulatory liabilities – Comprised of numerous immaterial components with remaining amortization periods at December 31, 2024 generally not exceeding one year for Alabama Power, three years for Georgia Power, one year for Mississippi Power, and 20 years for Southern Company Gas.

Alabama Power

Alabama Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Alabama PSC. Alabama Power currently recovers its costs from the regulated retail business primarily through Rate RSE, Rate CNP, Rate ECR, and Rate NDR. In addition, the Alabama PSC issues accounting orders to address current events impacting Alabama Power.

Petition for Certificate of Convenience and Necessity

On October 24, 2024, Alabama Power entered into an agreement to acquire all of the equity interests in Tenaska Alabama Partners, L.P. for a total purchase price of approximately $622 million, subject to working capital adjustments. Tenaska Alabama Partners, L.P. owns and operates the Lindsay Hill Generating Station, an approximately 855-MW combined cycle generation facility in Autauga County, Alabama. On October 30, 2024, Alabama Power filed a petition for a CCN with the Alabama PSC for authorization to procure additional generating capacity through the acquisition of the Lindsay Hill Generating Station.

As part of the acquisition, Alabama Power will assume an existing power sales agreement under which the full output of the generating facility remains committed to a third party through April 2027. Upon expiration of the power sales agreement, Alabama Power expects to recover costs associated with the Lindsay Hill Generating Station acquisition through Rate CNP New Plant, Rate CNP Compliance, Rate ECR, and Rate RSE.

The completion of the acquisition is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, approval by the Alabama PSC and the FERC, as well as the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act. Alabama Power expects to complete the acquisition by the end of the third quarter 2025.

The ultimate outcome of this matter cannot be determined at this time.

Renewable Generation Certificate

Through the issuance of a Renewable Generation Certificate (RGC), Alabama Power is authorized by the Alabama PSC to procure renewable capacity and energy and to market the related energy and environmental attributes to customers and other third parties. Under the original RGC, Alabama was authorized to procure up to 500 MWs of renewable capacity and energy. In June 2023, the Alabama PSC issued an order approving modifications to Alabama Power's RGC. The modifications authorized Alabama Power to procure an additional 2,400 MWs of renewable capacity and energy by June 14, 2029 and to market the related energy and environmental attributes to customers and other third parties. The modifications also increased the size of allowable renewable projects from 80 MWs to 200 MWs and increased the annual approval limit from 160 MWs to 400 MWs. Through December 31, 2024, Alabama Power has procured solar capacity totaling approximately 498 MWs under the RGC.

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted common equity return (WCER) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. When the projected WCER is under the allowed range, there is an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCER adjusting point if Alabama Power (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Alabama Power continues to reduce growth in total debt by increasing equity, with corresponding reductions in debt issuances, thereby de-leveraging its capital structure. Alabama Power's goal is to achieve an equity ratio of approximately 55% by the end of 2025. At December 31, 2024 and 2023, Alabama Power's equity ratio was approximately 53.9% and 52.3%, respectively.

Generally, during a year without a Rate RSE upward adjustment, if Alabama Power's actual WCER is between 6.15% and 7.65%, customers will receive 25% of the amount between 6.15% and 6.65%, 40% of the amount between 6.65% and 7.15%, and 75% of

the amount between 7.15% and 7.65%. Customers will receive all amounts in excess of an actual WCER of 7.65%. During a year with a Rate RSE upward adjustment, if Alabama Power's actual WCER exceeds 6.15%, customers receive 50% of the amount between 6.15% and 6.90% and all amounts in excess of an actual WCER of 6.90%. Alabama Power's ability to retain a portion of the revenue that causes the actual WCER for a given year to exceed the allowed range positions Alabama Power to address the pressure on its credit quality, without increasing retail rates under Rate RSE in the near term. There is no provision for additional customer billings should the actual retail return fall below the WCER range.

Retail rates under Rate RSE did not change for 2023 or 2024.

For the years ended December 31, 2022, 2023, and 2024, Alabama Power's WCER exceeded 6.15%, resulting in Alabama Power establishing a current regulatory liability of $62 million, $15 million, and $12 million, respectively, for Rate RSE refunds. In accordance with an Alabama PSC order issued in February 2023, Alabama Power refunded the 2022 amount to customers through bill credits in August 2023. The $15 million regulatory liability at December 31, 2023 was refunded to customers through bill credits in April 2024. The $12 million regulatory liability at December 31, 2024 will be refunded to customers through bill credits in May 2025.

On November 27, 2024, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2025, resulting in an increase of 4.87%, or $325 million annually, that became effective for the billing month of January 2025.

Excess Accumulated Deferred Income Tax Accounting Order

In 2022, the Alabama PSC directed Alabama Power to accelerate the amortization of a regulatory liability associated with excess federal accumulated deferred income taxes. Under this order, in 2023, approximately $304 million was returned to customers through bill credits to offset the impact of the rate increase discussed under "Rate CNP Depreciation" herein.

In October 2023, the Alabama PSC issued an order modifying its 2022 order and authorizing Alabama Power to (i) flow back in 2023 approximately $24 million of certain federal excess accumulated deferred income taxes resulting from the Tax Reform Legislation and (ii) make available any remaining balance of excess accumulated deferred income taxes at the end of 2023 for the benefit of customers in 2024 and/or 2025. At December 31, 2023, the remaining balance was $81 million, of which approximately $67 million was flowed back in 2024 and $14 million will flow back in 2025 for the benefit of customers.

Rate CNP New Plant

Rate CNP New Plant allows for recovery of Alabama Power's retail costs associated with newly developed or acquired certificated generating facilities placed into retail service.

In July 2022, the Alabama PSC approved a CCN authorizing Alabama Power to complete the acquisition of the Calhoun Generating Station. The transaction closed in September 2022, and, in October 2022, Alabama Power filed Rate CNP New Plant with the Alabama PSC to recover the related costs. The filing reflected an increase in annual revenues of $34 million, or 0.6%, effective with November 2022 billings.

In 2020, the Alabama PSC approved a CCN authorizing Alabama Power to complete the acquisition of the Central Alabama Generating Station, which occurred in August 2020. Through May 2023, Alabama Power recovered substantially all costs associated with the Central Alabama Generating Station through Rate RSE, offset by revenues from a power sales agreement. Beginning in July 2022, fuel costs associated with Central Alabama Generating Station are being recovered through Rate ECR. In March 2023, Alabama Power filed Rate CNP New Plant with the Alabama PSC to recover costs associated with the acquisition of the Central Alabama Generating Station. The filing reflected an annual increase in retail revenues of $78 million, or 1.1%, effective with June 2023 billings. On May 24, 2023, the Central Alabama Generating Station was placed into retail service.

The Alabama PSC's 2020 CCN also authorized Alabama Power to construct an approximately 720-MW combined cycle facility at Alabama Power's Plant Barry (Plant Barry Unit 8) and the recovery of estimated in-service costs. On November 1, 2023, the unit was placed in service. In December 2023, Alabama Power filed Rate CNP New Plant with the Alabama PSC to recover the related costs. The filing reflected an annual increase in retail revenues of $91 million, or 1.4%, effective with January 2024 billings.

Rate CNP PPA

Rate CNP PPA allows for the recovery of Alabama Power's retail costs associated with certificated PPAs. Revenues for Rate CNP PPA, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factors will have no significant effect on Southern Company's or Alabama Power's revenues or net income but will affect annual cash flow. No adjustments to Rate CNP PPA occurred during the period 2022 through 2024 and no adjustment is expected for 2025. At December 31, 2024 and 2023, Alabama Power had an under recovered Rate CNP PPA balance of $84 million and $103 million, respectively, of which $17 million and $18 million, respectively, is included in other regulatory assets, current and $67 million and $85 million, respectively, is included in other regulatory assets, deferred on Southern Company's and Alabama Power's balance sheets.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of Alabama Power's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting Alabama Power's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to factors that are calculated and submitted to the Alabama PSC by December 1 with rates effective for the following calendar year. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factors will have no significant effect on Southern Company's or Alabama Power's revenues or net income, but will affect annual cash flow. Changes in Rate CNP Compliance-related operations and maintenance expenses and depreciation generally will have no effect on net income.

In December 2022, December 2023, and November 2024, Alabama Power submitted calculations to the Alabama PSC associated with its cost of complying with governmental mandates for the following calendar year, as provided under Rate CNP Compliance. The 2022 filing reflected a $255 million, or 3.7%, annual increase effective with January 2023 billings, primarily due to updated depreciation rates. The 2023 filing reflected a $23 million, or 0.3%, annual decrease effective with January 2024 billings. The 2024 filing reflected a projected under recovered retail revenue requirement of $50 million. On December 3, 2024, the Alabama PSC issued a consent order requiring Alabama Power to leave the 2024 Rate CNP Compliance factors in effect for 2025, with any prior year under collected amount deemed recovered before any current year amounts are recovered, and any remaining under recovered amounts reflected in the 2025 filing.

At December 31, 2024, Alabama Power had an under recovered Rate CNP Compliance balance of $35 million which is included in other regulatory assets, deferred on Southern Company's and Alabama Power's balance sheets. At December 31, 2023, Alabama Power had an under recovered Rate CNP Compliance balance of $33 million, of which $8 million is included in other regulatory assets, current and $25 million is included in other regulatory assets, deferred on Southern Company's and Alabama Power's balance sheets.

Rate CNP Depreciation

In 2022, the Alabama PSC approved Rate CNP Depreciation, which allows Alabama Power to recover changes in depreciation resulting from updates to certain depreciation rates, excluding any depreciation recovered through Rate CNP New Plant, Rate CNP Compliance, or costs associated with the capitalization of asset retirement costs. Rate CNP Depreciation resulted in an annual revenue increase of approximately $318 million, or 4.6%, effective with January 2023 billings. No adjustments to Rate CNP Depreciation occurred during 2024 and no adjustment is expected for 2025.

Rate ECR

Rate ECR recovers Alabama Power's retail energy costs based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed gives rise to the over or under recovered amounts recorded as regulatory assets or liabilities. Alabama Power, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment

to billing rates is required. Changes in the Rate ECR factor have no significant effect on Southern Company's or Alabama Power's net income but will impact the related operating cash flows. The Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH.

The Alabama PSC approved adjustments to Rate ECR from 1.960 cents per KWH to 2.557 cents per KWH, or approximately $310 million annually, effective with August 2022 billings and from 2.557 cents per KWH to 3.510 cents per KWH, or approximately $500 million annually, effective with December 2022 billings. In November 2023, the Alabama PSC approved a decrease to Rate ECR from 3.510 cents per KWH to 3.270 cents per KWH, or approximately $126 million annually, effective with December 2023 billings. On May 7, 2024, the Alabama PSC approved a decrease to Rate ECR from 3.270 cents per KWH to 3.015 cents per KWH, or approximately $135 million annually, effective with July 2024 billings. On December 3, 2024, the Alabama PSC approved an additional reduction to Rate ECR from 3.015 cents per KWH to 2.600 cents per KWH, or $218 million annually, effective with January 2025 billings. The rate will adjust to 5.910 cents per KWH in January 2026 absent a further order from the Alabama PSC.

At December 31, 2024, Alabama Power's over recovered fuel costs totaled $29 million and is included in other regulatory liabilities, current on Southern Company's and Alabama Power's balance sheets. At December 31, 2023, Alabama Power's under recovered fuel costs totaled $246 million and is included in regulatory assets – under recovered retail fuel clause revenues on Southern Company's and Alabama Power's balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a significant impact on the timing of any recovery or return of fuel costs.

Plant Greene County

Alabama Power jointly owns Plant Greene County Units 1 and 2 with an affiliate, Mississippi Power. See Note 5 under "Joint Ownership Agreements" for additional information. Mississippi Power's 2024 IRP includes a schedule to retire Mississippi Power's 40% ownership interest in Plant Greene County Units 1 and 2 by the end of 2028. Alabama Power currently expects to retire Plant Greene County Units 1 and 2 (300 MWs based on 60% ownership) by the end of 2028. Alabama Power and Mississippi Power have continued to evaluate operating conditions and business needs relevant to the anticipated retirement of Plant Greene County Units 1 and 2. The ultimate outcome of this matter cannot be determined at this time. See "Mississippi Power – Integrated Resource Plans" herein for additional information.

Rate NDR

Based on an order from the Alabama PSC, Alabama Power maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. When the reserve balance falls below $50 million, a reserve establishment charge will be activated (and the on-going reserve maintenance charge concurrently suspended) until the reserve balance reaches $75 million.

The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 48-month period (24-month period prior to modifications approved by the Alabama PSC in 2022). The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. The maximum total Rate NDR charge was limited to $10.00 per month per non-residential customer account and $5.00 per month per residential customer account through July 12, 2022. Subsequently, modifications approved by the Alabama PSC replaced the maximum total Rate NDR charge with a maximum charge to recover a deficit of $5.00 per month per non-residential customer account and $2.50 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant, which can be used to offset storm charges. Alabama Power made an additional accrual of $21 million in 2024.

Alabama Power collected approximately $12 million, $12 million, and $14 million in 2024, 2023, and 2022, respectively, under Rate NDR. Beginning with August 2022 billings, the reserve establishment charge was suspended and the reserve maintenance charge was activated as a result of the NDR balance exceeding $75 million. Alabama Power expects to collect approximately $12

million annually under Rate NDR unless the NDR balance falls below $50 million. At December 31, 2024 and 2023, the NDR balance was $70 million and $76 million, respectively, and is included in other regulatory liabilities, deferred on Southern Company's and Alabama Power's balance sheets.

As revenue from the Rate NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, the Rate NDR charge will not have an effect on net income but will impact operating cash flows.

Reliability Reserve Accounting Order

In 2022, the Alabama PSC approved an accounting order authorizing Alabama Power to create a reliability reserve separate from the NDR and transition the previous Rate NDR authority related to reliability expenditures to the reliability reserve. Alabama Power may make accruals to the reliability reserve if the NDR balance exceeds $35 million. In July 2023, the Alabama PSC issued an order authorizing Alabama Power to expand the existing authority of its reliability reserve to include certain production-related expenses that are intended to maintain reliability in between scheduled generating unit maintenance outages.

At December 31, 2022, Alabama Power accrued $166 million to the reserve. In August 2023 and on September 18, 2024, Alabama Power notified the Alabama PSC of its intent to use a portion of its reliability reserve balance in 2023 and 2024, respectively. As a result, Alabama Power had usage of the reliability reserve in the amount of $23 million and $12 million during the fourth quarter 2023 and 2024, respectively, for reliability-related transmission, distribution, and generation expenses and nuclear production-related expenses.

At December 31, 2024 and 2023, Alabama Power's reliability reserve balance was $131 million and $143 million, respectively, and is included in other regulatory liabilities, deferred on Southern Company's and Alabama Power's balance sheets.

Environmental Accounting Order

Based on an order from the Alabama PSC, Alabama Power is authorized to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements, caused by environmental regulations. The regulatory asset is amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement, through Rate CNP Compliance.

With the completion of the Calhoun Generating Station acquisition, Alabama Power expected to retire Plant Barry Unit 5 in late 2023 or early 2024, subject to certain operating conditions. In 2022, Alabama Power reclassified approximately $600 million for Plant Barry Unit 5 from plant in service, net of depreciation to other utility plant, net and will continue to depreciate the asset according to the original depreciation rates. Alabama Power has continued to evaluate operating conditions relevant to the expected retirement of Plant Barry Unit 5 and now expects to retire the unit on or before December 31, 2028. At retirement, Alabama Power will reclassify the remaining net investment costs of the unit to a regulatory asset to be recovered over the unit's remaining useful life, as established prior to the decision to retire, through Rate CNP Compliance. See "Rate CNP New Plant" herein for additional information.

Georgia Power

Georgia Power's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. Georgia Power recovers its costs from the regulated retail business through traditional base tariffs, Demand-Side Management (DSM) tariffs, the ECCR tariff, and Municipal Franchise Fee (MFF) tariffs. These tariffs were set under the 2019 ARP for the years 2020 through 2022 and under the 2022 ARP for the years 2023 through 2025 as described herein. In addition, fuel costs are collected through a separate fuel cost recovery tariff.

See "Nuclear Construction – Regulatory Matters" herein for information regarding the approved recovery through retail base rates of certain costs related to Plant Vogtle Unit 3 and the common facilities shared between Plant Vogtle Units 3 and 4 (Common Facilities) that became effective August 1, 2023 based on the in-service date of July 31, 2023 for Unit 3, as well as base rate adjustments for the remaining costs related to Plant Vogtle Units 3 and 4 that became effective May 1, 2024 based on the in-service date of April 29, 2024 for Unit 4. Financing costs on certified construction costs of Plant Vogtle Units 3 and 4 were

collected through Georgia Power's NCCR tariff until the inclusion of certified construction costs in rate base. When the base rate adjustments occurred following commercial operation of Unit 4, the NCCR tariff ceased to be collected and financing costs are now included in Georgia Power's general retail revenue requirements. See "Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

Rate Plans

2022 ARP

In 2022, the Georgia PSC voted to approve the 2022 ARP, under which Georgia Power increased its rates on January 1, 2023. In November 2023 and on December 17, 2024, the Georgia PSC approved tariff adjustments effective January 1, 2024 and 2025, respectively. Details of tariff adjustments are provided in the following table:

Tariff	2023	2024	2025
		(in millions)	
Traditional base[a]	$ 194	$ 275	$ 194
ECCR	(21)	(99)	126
DSM	37	10	(22)
MFF	6	5	9
Total[b]	$ 216	$ 191	$ 306

(a) For 2025, net of $122 million related to the Georgia state tax rate reduction.

(b) Totals may not add due to rounding.

In the 2022 ARP, the Georgia PSC approved recovery through the ECCR tariff of estimated CCR ARO compliance costs for 2023, 2024, and 2025 over four-year periods beginning January 1 of each respective year, with recovery of construction contingency beginning in the year following actual expenditures, resulting in $20 million and $60 million reductions in the related amortization for 2023 and 2024, respectively, and an increase of $123 million in the related amortization for 2025. Compliance costs incurred were $300 million and $265 million in 2023 and 2024, respectively, and are expected to be $330 million in 2025. The CCR ARO costs are expected to be revised for actual expenditures and updated estimates through future annual compliance filings.

Further, under the 2022 ARP, Georgia Power's retail ROE is set at 10.50% and its equity ratio is set at 56%. Earnings will be evaluated against a retail ROE range of 9.50% to 11.90%. Any retail earnings above 11.90% will be shared, with 40% being applied to reduce regulatory assets, 40% directly refunded to customers, and the remaining 20% retained by Georgia Power. There will be no recovery of any earnings shortfall below 9.50% on an actual basis. However, if at any time during the term of the 2022 ARP, Georgia Power projects that its retail earnings will be below 9.50% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff to adjust Georgia Power's retail rates to achieve a 9.50% ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff would expire at the earlier of January 1, 2026 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case. In 2023 and 2024, Georgia Power's retail ROE was within the allowed retail ROE range.

Georgia Power is required to file a general base rate case by July 1, 2025, in response to which the Georgia PSC would be expected to determine whether the 2022 ARP should be continued, modified, or discontinued.

2019 ARP

Georgia Power's retail ROE under the 2019 ARP was set at 10.50% and earnings were evaluated against a retail ROE range of 9.50% to 12.00%. Any retail earnings above 12.00% were shared, with 40% applied to reduce regulatory assets, 40% directly refunded to customers, and the remaining 20% retained by Georgia Power. In 2022, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power reduced regulatory assets by $117 million and refunded $117 million to customers through bill credits in the first quarter 2023.

Integrated Resource Plans

2022 IRP

In 2022, the Georgia PSC approved Georgia Power's 2022 IRP, as modified by a stipulation among Georgia Power, the staff of the Georgia PSC, and certain intervenors and as further modified by the Georgia PSC.

In the 2022 IRP decision, the Georgia PSC approved, among other things, the certification of six PPAs (including five affiliate PPAs with Southern Power that are subject to approval by the FERC) with capacities of 1,567 MWs beginning in 2024, 380 MWs beginning in 2025, and 228 MWs beginning in 2028, procured through a capacity request for proposals (RFP) authorized in the 2019 IRP. On June 27, 2024, the FERC approved the five affiliate PPAs with Southern Power. See Note 9 for additional information.

In the third quarter 2024, Georgia Power entered into an agreement for engineering, procurement, and construction of a 265-MW battery energy storage facility, which is projected to be placed in service in 2026, as authorized in the 2022 IRP. Georgia Power is required to file quarterly construction monitoring reports with the Georgia PSC through commercial operation. The ultimate outcome of this matter cannot be determined at this time.

As included in the 2022 IRP final order, Georgia Power initiated an RFP of up to 8,500 MWs of capacity from a variety of resources with expected CODs or delivery commencement dates between 2028 and 2030. The RFP included Georgia Power-owned proposals. In conjunction with those proposals, Georgia Power entered into agreements for engineering, procurement, and construction through January 2025. Winning participants are expected to be notified in June 2025, and the Georgia PSC is anticipated to render a decision related to the certification of the winning submissions in the fourth quarter 2025. Depending on the outcomes of the RFP and certification processes, Georgia Power could spend up to $14 billion, excluding AFUDC, on approved Georgia Power-owned proposals and related transmission investments through 2029. The ultimate outcome of this matter cannot be determined at this time.

2023 IRP Update

On April 16, 2024, the Georgia PSC approved Georgia Power's updated IRP as modified by a stipulation among Georgia Power, the staff of the Georgia PSC, and certain intervenors (2023 IRP Update), which set forth a plan to support the recent increase in the state of Georgia's economic development and Georgia Power's projected energy needs since the 2022 IRP. In the 2023 IRP Update decision, the Georgia PSC approved the following requests:

- Authority to develop, own, and operate up to 1,400 MWs from three simple cycle combustion turbines at Plant Yates with the recoverable costs not to exceed the certified amount, which was approved by the Georgia PSC on August 20, 2024. With this approval, the Georgia PSC recognized the potential for circumstances beyond Georgia Power's control that could cause the project costs to exceed the certified amount, in which case Georgia Power would provide documentation to the Georgia PSC to explain and justify potential recovery of additional reasonable and prudent costs. Georgia Power is required to file semi-annual construction monitoring reports with the Georgia PSC through commercial operation, the first of which was filed on February 14, 2025.
- Certification of an affiliate PPA with Mississippi Power for 750 MWs, which began January 1, 2024 and will continue through December 2028.
- Certification of a non-affiliate PPA for 230 MWs, which began May 1, 2024 and will continue through December 2028.
- Authority to develop, own, and operate up to 500 MWs of battery energy storage facilities, including storage systems co-located with existing Georgia Power-owned solar facilities with the recoverable costs not to exceed the certified amount, as approved by the Georgia PSC on December 3, 2024, as well as the issuance of an expedited RFP for an additional 500 MWs of battery energy storage facilities. Georgia Power is required to file quarterly construction monitoring reports for Georgia Power-owned resources with the Georgia PSC through commercial operation.
- Approval of transmission projects necessary to support the generation resources approved in the 2023 IRP Update.

The 2023 IRP Update assumed a retirement date at the end of 2035 for Plant Bowen Units 1 and 2 (1,400 MWs). See "2025 IRP" herein for additional information.

On January 12, 2024, Georgia Power entered into an agreement for engineering, procurement, and construction to construct three 442-MW simple cycle combustion turbine units at Plant Yates (Plant Yates Units 8, 9, and 10), which are projected to be placed in service in the fourth quarter 2026, the second quarter 2027, and the third quarter 2027, respectively.

In the third quarter 2024, Georgia Power entered into agreements for engineering, procurement, and construction of four battery energy storage facilities totaling 500 MWs, which are projected to be placed in service in 2026.

At December 31, 2024, Georgia Power had recorded approximately $760 million of combined capital costs, excluding AFUDC, for the 265-MW battery energy storage facility approved in the 2022 IRP, the 500 MWs of battery energy storage facilities approved in the 2023 IRP Update, and the 1,400 MWs from three simple cycle combustion turbines at Plant Yates approved in the 2023 IRP Update. The total certified amounts related to these projects are approximately $2.8 billion, excluding AFUDC.

The ultimate outcome of these matters cannot be determined at this time.

2025 IRP

On January 31, 2025, Georgia Power filed its triennial IRP (2025 IRP). The filing includes a request to extend the operation of Plant Scherer Unit 3 (614 MWs based on 75% ownership) through at least December 31, 2035 and Plant Gaston Units 1 through 4 (500 MWs based on 50% ownership through SEGCO) through at least December 31, 2034. See Note 7 under "SEGCO" for additional information.

As in the 2023 IRP Update, Plant Bowen Units 1 and 2 are also assumed to operate through at least the end of 2035.

In addition, the 2025 IRP includes, among other things, requests for approval of the following:

- Pursuit of installation of environmental controls and natural gas co-firing at Plant Bowen Units 1 through 4 (3,160 MWs), Plant Scherer Units 1 and 2 (137 MWs based on 8.4% ownership), and Plant Scherer Unit 3 for compliance with both ELG supplemental rules and GHG rules.
- Upgrades to Plant McIntosh Units 10 and 11 (1,319 MWs) for a projected 194 MWs of incremental capacity by 2028 and Plant McIntosh Units 1 through 8 (640 MWs) for a projected 74 MWs of incremental capacity by 2033.
- Upgrades to Plant Hatch Units 1 and 2 (900 MWs based on 50.1% ownership) and Plant Vogtle Units 1 and 2 (1,060 MWs based on 45.7% ownership) for a projected 112 MWs of incremental capacity, some of which would be available as early as 2028.
- Investments related to the continued reliable hydro operations of nine facilities, as well as the authority to develop, own, and operate a projected incremental 16 MWs from Plant Goat Rock Units 3 through 6.
- RFPs for at least 1,100 MWs of utility scale and distributed generation renewable resources. Georgia Power is seeking to add up to 4,000 MWs of incremental renewable resources by 2035.
- Issuance of a capacity RFP to procure resources to meet capacity needs in 2032 and 2033.
- Strategic power delivery infrastructure plan necessary to help ensure adequate reliability and serve the projected future load growth expected in Georgia.
- Certification of approximately 187 MWs of wholesale capacity associated with Plant Scherer Unit 3 to be placed in retail rate base, some of which is projected to be available in 2026.

A decision from the Georgia PSC on the 2025 IRP is expected in July 2025. The ultimate outcome of these matters cannot be determined at this time.

Transmission Asset Sales

On March 7, 2024, the FERC approved the sale of transmission line assets under the integrated transmission system agreement, with a net book value of $236 million. On April 24, 2024, the sale, with a purchase price of $351 million, was completed resulting in a pre-tax gain of approximately $114 million ($84 million after tax) recorded in the second quarter 2024.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. During 2022, Georgia Power's under recovered fuel balance increased significantly due to higher fuel and purchased power costs. In May 2023, the Georgia PSC approved a stipulation between Georgia Power and the staff of the Georgia PSC to increase annual fuel billings by 54%, or approximately $1.1 billion, effective June 1, 2023. The increase includes a three-year recovery period for $2.2 billion of Georgia Power's under recovered fuel balance at May 31, 2023. Under the approved stipulation, Georgia Power is allowed to adjust its fuel cost recovery rates under an interim fuel rider prior to the next fuel case, subject to a maximum 40% cumulative change, if its under or over recovered fuel balance accumulated since May 31, 2023 exceeds $200 million. Georgia Power is scheduled to file its next fuel case no later than February 28, 2026.

Georgia Power's under recovered fuel balance totaled $1.2 billion at December 31, 2024, of which $713 million is included in under recovered fuel clause revenues and under recovered retail fuel clause revenues on Southern Company's and Georgia Power's balance sheets, respectively, and $453 million is included in deferred under recovered retail fuel clause revenues on Southern Company's and Georgia Power's balance sheets. The under recovered fuel balance totaled $1.9 billion at December 31, 2023, of which $694 million is included in under recovered fuel clause revenues and under recovered retail fuel clause revenues on Southern Company's and Georgia Power's balance sheets, respectively, and $1.2 billion is included in deferred under recovered retail fuel clause revenues on Southern Company's and Georgia Power's balance sheets.

Georgia Power's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 36-month time horizon.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's or Georgia Power's revenues or net income but will affect operating cash flows.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. During 2022, Georgia Power recovered $213 million annually under the 2019 ARP. Beginning January 1, 2023, Georgia Power is recovering $31 million annually under the 2022 ARP. At December 31, 2023, Georgia Power's regulatory asset balance related to storm damage was $54 million, of which $31 million is included in other regulatory assets, current and $23 million is included in other regulatory assets, deferred on Southern Company's and Georgia Power's balance sheets. During September 2024, Hurricane Helene caused significant damage to Georgia Power's transmission and distribution facilities. The incremental restoration costs related to this hurricane totaled approximately $870 million, of which approximately $750 million was deferred in the regulatory asset for storm damage, approximately $90 million was capitalized to property, plant, and equipment, and approximately $30 million was deferred to be billed in 2025 to open access transmission tariff customers. At December 31, 2024, Georgia Power's regulatory asset balance related to storm damage was $827 million, of which $31 million is included in other regulatory assets, current and $795 million is included in other regulatory assets, deferred on Southern Company's and Georgia Power's balance sheets. The rate of storm damage cost recovery is expected to be adjusted in future regulatory proceedings as necessary. As a result of this regulatory treatment, costs related to storms are not expected to have a material impact on Southern Company's or Georgia Power's net income but do impact the related operating cash flows. See Note 1 under "Storm Damage and Reliability Reserves" for additional information.

Nuclear Construction

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4, in which Georgia Power holds a 45.7% ownership interest. In 2012, the NRC issued the related combined construction and operating licenses, which allowed full construction of the two AP1000 nuclear units (with electric generating capacity of approximately 1,100 MWs each) and related facilities to begin.

In 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, under which Bechtel is reimbursed for actual costs plus a base fee and an at-risk fee, subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Vogtle Owner is severally (not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement.

See Note 8 under "Long-term Debt – DOE Loan Guarantee Borrowings" for information on the Amended and Restated Loan Guarantee Agreement, including applicable covenants, events of default, and mandatory prepayment events.

Cost and Schedule

Georgia Power placed Unit 3 and Unit 4 in service on July 31, 2023 and April 29, 2024, respectively. During the second quarter 2024, following Unit 4's in-service date, Southern Nuclear evaluated the remaining expected site demobilization costs and other contractor obligations and reduced the remaining estimate to complete forecast by approximately $21 million, including the impact of joint owner cost-sharing described below. Accordingly, Georgia Power recorded a pre-tax credit to income of approximately $21 million ($16 million after tax), including the joint owner impacts described below, in the second quarter 2024 to recognize forecasted capital costs previously charged to income.

Georgia Power's net capital costs incurred through December 31, 2024 in connection with Plant Vogtle Units 3 and 4, and its approximate proportionate share of additional capital costs to be incurred after December 31, 2024, including completion of site demobilization and remaining contractor obligations, is as follows:

	(in millions)
Total project capital cost forecast[a][b]	$ 10,732
Net investment at December 31, 2024[b]	(10,663)
Remaining estimate to complete	**$ 69**

(a) Includes approximately $1.2 billion of costs that are not shared with the other Vogtle Owners. Excludes financing costs capitalized through AFUDC of approximately $440 million accrued through Unit 4's in-service date.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related customer refunds.

Georgia Power's financing costs for construction of Plant Vogtle Units 3 and 4 totaled approximately $3.53 billion, of which $3.08 billion had been recovered through Unit 4's in-service date.

Pursuant to the regulatory orders discussed below, any further changes to the capital cost forecast will not be recoverable through regulated rates and will be required to be charged or credited to income. Such charges or credits are not expected to be material.

Georgia Power previously reached agreements with MEAG Power, OPC, and Dalton to resolve its respective dispute with each regarding the cost-sharing and tender provisions of the joint ownership agreements, as amended (Vogtle Joint Ownership Agreements). Under the terms of these agreements, among other items, Georgia Power will reimburse a portion of MEAG Power's, OPC's, and Dalton's costs of construction for Plant Vogtle Units 3 and 4 as such costs are incurred and with no further adjustment for force majeure costs, which payments (including amounts paid to date) will total approximately $91 million, $99 million, and $5.3 million for MEAG Power, OPC, and Dalton, respectively, based on the current project capital cost forecast. Georgia Power will also reimburse 20% of MEAG Power's costs of construction and 66% of each of OPC's and Dalton's costs of construction with respect to any amounts over the current project capital cost forecast, with no further adjustment for force majeure costs.

Georgia Power recorded pre-tax charges to income through 2023 of $567 million ($424 million after tax) and a pre-tax credit to income in the second quarter 2024 of $7.6 million ($5.7 million after tax) associated with the cost-sharing provisions of the Vogtle Joint Ownership Agreements, including the settlements with the other Vogtle Owners described above. These charges are included in the total project capital cost forecast and will not be recovered from retail customers.

The ultimate impact of these matters on the project capital cost forecast for Plant Vogtle Units 3 and 4 is not expected to be material.

Regulatory Matters

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4 with a certified capital cost of $4.418 billion. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allowed Georgia Power to recover financing costs for Plant Vogtle Units 3 and 4. Financing costs were recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion. Financing costs related to capital costs above $4.418 billion up

to $7.562 billion approved for recovery as described below were recognized through AFUDC and are being recovered through retail rates over the life of Plant Vogtle Units 3 and 4; however, Georgia Power did not record AFUDC related to any capital costs in excess of $7.562 billion. In 2022, the Georgia PSC approved Georgia Power's filing to increase the NCCR tariff by $36 million annually, effective January 1, 2023. In November 2023, Georgia Power filed a request to continue for 2024 the NCCR tariff that was effective during 2023. The staff of the Georgia PSC accepted the proposal and no further approval from the Georgia PSC was required. See additional information below on AFUDC and the NCCR tariff following commercial operation of Unit 4.

In 2021, the Georgia PSC approved an order under which Georgia Power would include in rate base an allocation of $2.1 billion to Plant Vogtle Unit 3 and the Common Facilities from the $3.6 billion of Plant Vogtle Units 3 and 4 costs previously deemed prudent by the Georgia PSC and would recover the related depreciation through retail base rates effective the month after Unit 3 is placed in service. In compliance with the Georgia PSC order, Georgia Power increased annual retail base rates by $318 million effective August 1, 2023 based on the in-service date of July 31, 2023 for Unit 3. The related increase in annual retail base rates included recovery of all projected operations and maintenance expenses for Unit 3 and the Common Facilities and other related costs of operation, partially offset by the related PTCs. Financing costs (debt and equity) on the remaining portion of the total Unit 3 and the Common Facilities construction costs continued to be recovered through the NCCR tariff or deferred. Georgia Power deferred as a regulatory asset the debt component of financing costs as well as the remaining depreciation until Unit 4 costs were placed in retail base rates as described below. The regulatory assets for the debt component of financing costs and depreciation are being recovered over 10 years beginning May 2024, as approved by the Georgia PSC, with a remaining balance of $23 million and $29 million, respectively, at December 31, 2024. The equity component of financing costs ($39 million at December 31, 2024) represents an unrecognized ratemaking amount that is not reflected on Georgia Power's balance sheets. This amount will be recognized in Georgia Power's income statements in the periods it is billable to customers.

In December 2023, the Georgia PSC approved Georgia Power's application to adjust rates to include reasonable and prudent Plant Vogtle Units 3 and 4 costs as modified by the related stipulation (Prudency Stipulation) among Georgia Power, the staff of the Georgia PSC, and certain intervenors.

Under the terms of the approved Prudency Stipulation, Georgia Power will recover $7.562 billion in total construction and capital costs and associated retail rate base items of $1.02 billion, which includes AFUDC financing costs above $4.418 billion (the Georgia PSC-certified amount) up to $7.562 billion. Georgia Power will also recover projected operations and maintenance expenses, depreciation, nuclear decommissioning accruals, and property taxes, net of projected PTCs. After considering construction and capital costs already in retail base rates of $2.1 billion and $362 million of associated retail rate base items for Unit 3 and Common Facilities (approved by the Georgia PSC in 2021), Georgia Power included in retail rate base the remaining $5.462 billion of construction and capital costs as well as $647 million of associated retail rate base items effective with the April 29, 2024 in-service date for Unit 4. Annual retail base revenues increased approximately $730 million and the average retail base rates were adjusted by approximately 5% (net of the elimination of the NCCR tariff described below) effective May 1, 2024.

Reductions to the ROE used to calculate the NCCR tariff (pursuant to prior Georgia PSC orders) negatively impacted earnings by approximately $80 million through the second quarter 2024 and $310 million and $300 million in 2023 and 2022, respectively. Further, as included in the approved Prudency Stipulation, since commercial operation for Unit 4 was not achieved by March 31, 2024, Georgia Power's ROE used to determine the NCCR tariff and calculate AFUDC was reduced to zero effective April 1, 2024, which resulted in a negative impact to earnings of approximately $10 million (for one month) in the second quarter 2024 based on the April 29, 2024 in-service date. Effective May 1, 2024, following commercial operation of Unit 4, Georgia Power's NCCR tariff was eliminated and financing costs are included in Georgia Power's general retail revenue requirements. Financing costs of $10 million that were not recovered through the NCCR tariff will be addressed in Georgia Power's next retail base rate case proceeding.

As of each Unit's respective first refueling outage, if the respective Unit's performance has materially deviated from expected performance, the Georgia PSC may order Georgia Power to credit customers for operations and maintenance expenses or disallow costs associated with the repair or replacement of any system, structure, or component found to have caused the material deviation in performance if proven to be the result of imprudent engineering, construction, procurement, testing, or start-up. Unit 3 demonstrated high performance and reliability during the first 14 months of operation leading up to its first refueling outage, which took place in the fall of 2024 and no performance-related disallowance is expected. Unit 4 has also demonstrated high

performance and reliability since being placed in service and its first refueling outage is projected to begin in the fall of 2025. The ultimate outcome of these matters cannot be determined at this time.

The approval of the Prudency Stipulation resolved all issues for determination by the Georgia PSC regarding the reasonableness, prudence, and cost recovery for the remaining Plant Vogtle Units 3 and 4 construction and capital costs not already in retail base rates.

As a result of the Georgia PSC's approval of the Prudency Stipulation, Georgia Power recorded a pre-tax credit to income of approximately $228 million ($170 million after tax) in the fourth quarter 2023 to recognize CWIP costs previously charged to income, which are now recoverable through retail rates. Associated AFUDC on these costs, which totaled approximately $14 million, was also recognized.

Mississippi Power

Mississippi Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. Mississippi Power's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are expected to be recovered through Mississippi Power's base rates.

Performance Evaluation Plan

Mississippi Power's retail base rates generally are set under the PEP, a rate plan approved by the Mississippi PSC. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, PEP includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed ROE. PEP measures Mississippi Power's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). Typically, two PEP filings are made for each calendar year:

the PEP projected filing in March of the current year and the PEP lookback filing in March of the subsequent year. The annual PEP projected filings utilize a historic test year adjusted for "known and measurable" changes and discounted cash flow and regression formulas to determine base ROE. The PEP lookback filing reflects the actual revenue requirement.

In June 2022, the Mississippi PSC approved Mississippi Power's annual retail PEP filing, resulting in an annual increase in revenues of approximately $18 million, or 1.9%, effective with the first billing cycle of April 2022. In June 2023 and on June 13, 2024, the Mississippi PSC approved Mississippi Power's annual retail PEP filings for 2023 and 2024, respectively, with no change in retail rates.

Integrated Resource Plans

In 2020, the Mississippi PSC issued an order requiring Mississippi Power to incorporate into its 2021 IRP a schedule of early or anticipated retirement of 950 MWs of fossil-steam generation by year-end 2027 to reduce the excess reserve margin Mississippi Power anticipated at that time. The order stated that Mississippi Power will be allowed to defer any retirement-related costs as regulatory assets for future recovery.

In 2021, the Mississippi PSC concluded its review of Mississippi Power's 2021 IRP. The 2021 IRP included a schedule to retire Plant Watson Unit 4 (268 MWs) and Plant Greene County Units 1 and 2 (206 MWs based on 40% ownership) in December 2023, 2025, and 2026, respectively, consistent with each unit's remaining useful life in the most recent approved depreciation studies. In addition, the schedule reflected the early retirement of Plant Daniel Units 1 and 2 (502 MWs based on 50% ownership) by the end of 2027.

In October 2023, Mississippi Power signed an affiliate PPA with Georgia Power for 750 MWs of capacity, which began January 1, 2024 and will continue through December 2028.

On April 26, 2024, Mississippi Power filed its 2024 IRP with the Mississippi PSC. The Mississippi PSC did not note any deficiencies within the prescribed 120-day review period; therefore, the filing is concluded. The 2024 IRP included a schedule to

retire Plant Watson Unit 4 and Plant Greene County Units 1 and 2 and to retire early Plant Daniel Units 1 and 2, all by the end of 2028, which is consistent with the completion of Mississippi Power's affiliate PPA with Georgia Power. On January 9, 2025, Mississippi Power notified the Mississippi PSC of its intent to extend the retirement date of Plant Daniel Unit 2 and potentially extend the retirement dates of other fossil steam units beyond their current 2028 retirement dates in order to serve recently signed economic development loads of approximately 600 MWs.

The remaining net book value of Plant Daniel Units 1 and 2 was approximately $478 million at December 31, 2024, and Mississippi Power is continuing to depreciate these units using the current approved rates. Mississippi Power expects to reclassify the net book value remaining at retirement to a regulatory asset to be amortized over a period to be determined by the Mississippi PSC in future proceedings, consistent with the 2020 order. The Plant Watson and Plant Greene County units are expected to be fully depreciated upon retirement.

The ultimate outcome of these matters cannot be determined at this time.

Plant Daniel

On November 8, 2024, Mississippi Power entered into an agreement with FP&L to acquire FP&L's 50% ownership interest in Plant Daniel Units 1 and 2. This acquisition will include a payment by FP&L to Mississippi Power of between $35 million and $38 million, which represents an estimate of the incremental cost to Mississippi Power to assume ownership of FP&L's interest, based on the timing of the completion of the transaction. On January 7, 2025, the Mississippi PSC approved Mississippi Power's request for (i) the inclusion of the acquired assets and the associated costs at Plant Daniel in Mississippi Power's retail rate base, upon completion of the transaction, (ii) the establishment of a new regulatory liability account in which all of the proceeds to be paid by FP&L will be recorded, and (iii) Mississippi Power's ability to amortize that regulatory liability by charging certain expenditures against it. The completion of the transaction is subject to the satisfaction or waiver of certain conditions, including, among other customary closing conditions, approval by the Florida PSC. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

The Mississippi PSC has authorized Mississippi Power to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations.

In April 2022, April 2023, and May 2024, the Mississippi PSC approved Mississippi Power's annual ECO Plan filings, resulting in increases in revenues of approximately $1 million annually effective with the first billing cycle of May 2022, $3 million annually effective with the first billing cycle of May 2023, and $9 million annually effective with the first billing cycle of June 2024, respectively.

On February 14, 2025, Mississippi Power submitted its annual ECO Plan filing to the Mississippi PSC, which requested a $6 million annual increase in revenues. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

Mississippi Power annually establishes, and is required to file for an adjustment to, the retail fuel cost recovery factor that is approved by the Mississippi PSC. The Mississippi PSC approved an increase of $43 million effective in February 2022. On February 6, 2024, the Mississippi PSC approved Mississippi Power's request to increase retail fuel revenues by $18 million annually effective with the first billing cycle of March 2024. The approved filing included the deferral of approximately $61 million of under recovered fuel costs as of October 2023. On January 7, 2025, the Mississippi PSC approved Mississippi Power's request for no change in retail fuel revenues effective with the first billing cycle of February 2025. The approved filing included the deferral of approximately $25 million of under recovered fuel costs as of October 2024, which is expected to be included in Mississippi Power's next fuel filing. Mississippi Power will continue to accrue its weighted-average cost of capital on any under or over fuel recovery balance.

At December 31, 2024, Mississippi Power had $32 million of deferred under recovered retail fuel clause revenues primarily associated with its fuel-hedging program and $32 million of over recovered retail fuel clause revenues primarily related to lower recoverable fuel costs on its balance sheet. At December 31, 2023, Mississippi Power had $50 million of deferred under recovered

retail fuel clause revenues and $27 million of over recovered retail fuel clause revenues primarily associated with its fuel-hedging program on its balance sheet. See Note 1 under "Fuel Costs" for additional information.

Mississippi Power has wholesale MRA and Market Based (MB) fuel cost recovery factors. Effective with the first billing cycles for January 2023, 2024, and 2025, annual revenues under the wholesale MRA fuel rate increased $22 million, decreased $4 million, and decreased $19 million, respectively. At December 31, 2024 and 2023, wholesale MRA fuel costs were over recovered $19 million and $5 million, respectively, and were included in other current liabilities on Mississippi Power's balance sheets. The wholesale MB fuel rate did not change materially in any period presented. The wholesale MB fuel cost recovery was immaterial for both periods presented.

Mississippi Power's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on Mississippi Power's revenues or net income but will affect operating cash flows.

Ad Valorem Tax Adjustment

Mississippi Power annually establishes an ad valorem tax adjustment factor that is approved by the Mississippi PSC. Any changes are not expected to have a significant effect on Mississippi Power's net income but will affect operating cash flows. Effective with the first billing cycle of July 2022, June 2023, and July 2024, the Mississippi PSC approved changes in annual revenues collected through the ad valorem tax adjustment factor resulting in a $5 million increase, a $7 million decrease, and a $5 million decrease, respectively.

System Restoration Rider

Mississippi Power carries insurance for the cost of certain types of damage to generation plants and general property. However, Mississippi Power is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, Mississippi Power accrues for the cost of such damage through an annual expense accrual which is credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. Every year, the Mississippi PSC, the MPUS, and Mississippi Power agree on SRR revenue level(s). In the event the expected annual charges exceed the annual accrual or the target balance has been met, Mississippi Power and the Mississippi PSC will determine the appropriate change to the annual accrual. Additionally, if PEP earnings are above a certain threshold, Mississippi Power has the ability to apply any required PEP refund as an additional accrual to the property damage reserve in lieu of customer refunds.

Mississippi Power's net retail SRR accrual, which includes carrying costs and previously included amortization of related excess deferred income tax benefits, was $12.6 million in 2024, $11.7 million in 2023, and $6.9 million in 2022. At December 31, 2024 and 2023, the retail property damage reserve balance was $52 million and $45 million, respectively, and is included in other regulatory liabilities, deferred on Mississippi Power's balance sheets.

In 2021, the Mississippi PSC approved Mississippi Power's annual SRR filing, which requested an increase in retail revenues of approximately $9 million annually effective with the first billing cycle of March 2022. In April 2023, the Mississippi PSC approved Mississippi Power's annual SRR filing, with no change in retail rates. Mississippi Power's minimum annual SRR accrual was increased

from $8.3 million to $11.7 million. On April 11, 2024, the Mississippi PSC approved Mississippi Power's annual SRR filing to the Mississippi PSC, with no change in retail rates. Mississippi Power's minimum annual SRR accrual was increased from $11.7 million to $12.6 million.

Reliability Reserve Accounting Order

In 2022, the Mississippi PSC approved an accounting order authorizing Mississippi Power to create a reliability reserve to offset future generation, transmission, and distribution reliability-related expenditures for use in a future year. Mississippi Power may make accruals to the reliability reserve each year after meeting with the MPUS and Mississippi PSC staff. Mississippi Power will provide annually, through its capital plan, energy delivery plan, or PEP filing, any amounts to be charged against the reliability reserve during the current year. During 2024, 2023, and 2022, Mississippi Power accrued $21 million, $11 million, and $25 million, respectively, to the reliability reserve. At December 31, 2024 and 2023, the reliability reserve balance was

$57 million and $36 million, respectively, and is included in other regulatory liabilities, deferred on Mississippi Power's balance sheets.

Municipal and Rural Associations Tariff

Mississippi Power provides wholesale electric service to Cooperative Energy, East Mississippi Electric Power Association, and the City of Collins, all located in southeastern Mississippi, under a long-term, cost-based, FERC-regulated MRA tariff.

In 2017, Mississippi Power and Cooperative Energy executed, and the FERC accepted, a Shared Service Agreement (SSA), as part of the MRA tariff, under which Mississippi Power and Cooperative Energy share in providing electricity to the Cooperative Energy delivery points under the tariff. In August 2022, the FERC accepted an amended SSA between Mississippi Power and Cooperative Energy, effective July 1, 2022, under which Cooperative Energy will continue to decrease its use of Mississippi Power's generation services under the MRA tariff up to 2.5% annually through 2035. At December 31, 2024, Mississippi Power is serving approximately 385 MWs of Cooperative Energy's annual demand. Beginning in 2036, Cooperative Energy will provide 100% of its electricity requirements at the MRA delivery points under the tariff. Neither party has the option to cancel the amended SSA.

In October 2023, the FERC approved a settlement agreement filed by Mississippi Power and Cooperative Energy in July 2023 related to Mississippi Power's July 2022 request for a $23 million increase in annual wholesale base revenues under the MRA tariff. The settlement agreement provided for a $16 million increase in annual wholesale base revenues, effective September 14, 2022, and a refund to customers of approximately $6 million, which was completed in November 2023, primarily related to the difference between the approved rates and interim rates.

On May 28, 2024, the FERC issued an order accepting Mississippi Power's request for an $8 million increase in annual wholesale base revenues under the MRA tariff, effective May 29, 2024, subject to refund. On December 23, 2024, Mississippi Power and Cooperative Energy filed a settlement agreement with the FERC. The settlement agreement provides for (i) a $1 million increase in annual wholesale base revenues and a refund to customers of approximately $4 million, (ii) a rate escalation of 2.5% on an annual basis in periods subsequent to December 31, 2024 and continuing through the end of the SSA on December 31, 2035, and (iii) a waiver of rights by Mississippi Power and Cooperative Energy to file for any changes in non-fuel rates through the end of the term of the SSA. The settlement agreement is subject to approval by the FERC. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

Utility Regulation and Rate Design

The natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies. Rates charged to customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable ROE.

As a result of operating in a deregulated environment, Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically. The Marketers add these fixed charges when billing their respective customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. Southern Company Gas has various mechanisms, such as weather and revenue normalization mechanisms and weather derivative instruments, that limit exposure to weather changes within typical ranges in these utilities' respective service territories.

In addition to natural gas cost recovery mechanisms, other cost recovery mechanisms and regulatory riders, which vary by utility, allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation, energy efficiency plans, and bad debts. In traditional rate designs, utilities recover a significant portion of the fixed

customer service and pipeline infrastructure costs based on assumed natural gas volumes used by customers. With the exception of Chattanooga Gas, the natural gas distribution utilities have decoupled regulatory mechanisms that Southern Company Gas believes encourage conservation by separating the recoverable amount of these fixed costs from the amounts of natural gas used by customers. See "Rate Proceedings" herein for additional information. Also see "Infrastructure Replacement Programs and Capital Projects" herein for additional information regarding infrastructure replacement programs at certain of the natural gas distribution utilities.

The following table provides regulatory information for Southern Company Gas' natural gas distribution utilities:

	Nicor Gas	Atlanta Gas Light	Virginia Natural Gas	Chattanooga Gas
Authorized ROE at December 31, 2024	9.51%	10.25%	9.70%	9.80%
Weather normalization mechanisms[a]			✓	✓
Decoupled, including straight-fixed-variable rates[b]	✓	✓	✓	
Regulatory infrastructure program rate[c]		✓	✓	✓
Bad debt rider[d]	✓		✓	✓
Energy efficiency plan[e]	✓		✓	
Annual base rate adjustment mechanism[f]		✓		✓
Year of last base rate case decision	2023	2019	2023	2018

(a) Designed to help stabilize operating results by allowing recovery of costs in the event of unseasonal weather, but are not direct offsets to the potential impacts on earnings of weather and customer consumption.

(b) Allows for recovery of fixed residential customer service costs separately from assumed natural gas volumes used by customers and provides a benchmark level of revenue for recovery.

(c) See "Infrastructure Replacement Programs and Capital Projects" herein for additional information. Chattanooga Gas' pipeline replacement program costs are recovered through its annual base rate review mechanism.

(d) The recovery (refund) of bad debt expense over (under) an established benchmark expense. The gas portion of bad debt expense is recovered through purchased gas adjustment mechanisms. Nicor Gas also has a rider to recover the non-gas portion of bad debt expense.

(e) Recovery of costs associated with plans to achieve specified energy savings goals.

(f) Regulatory mechanism allowing annual adjustments to base rates up or down based on authorized ROE and/or ROE range.

Infrastructure Replacement Programs and Capital Projects

In addition to capital expenditures recovered through base rates by each of the natural gas distribution utilities, Virginia Natural Gas has a separate rate rider that provides timely recovery of capital expenditures for specific infrastructure replacement programs, and Atlanta Gas Light has a separate rate rider that provides for the timely recovery of capital expenditures for a specific reinforcement capital program. Total capital expenditures incurred during 2024 for all gas distribution operations were $1.7 billion.

The following table and discussions provide updates on the infrastructure replacement programs and capital projects at the natural gas distribution utilities at December 31, 2024. These programs are risk-based and designed to update and replace cast iron, bare steel, and mid-vintage plastic materials or expand Southern Company Gas' distribution systems to improve reliability and meet operational flexibility and growth.

Utility	Program	Recovery	Capital Expenditures in 2024	Capital Expenditures Since Project Inception	Pipe Installed Since Project Inception	Scope of Program	Program Duration	Last Year of Program
			(in millions)		*(miles)*	*(miles)*	*(years)*	
Virginia Natural Gas	SAVE	Rider	$ 75	$ 561	598	938	18	2029
Atlanta Gas Light	System Reinforcement Rider	Rider	99	279	29	N/A	6	2027
Chattanooga Gas	Pipeline Replacement Program	Rate Base	12	28	24	73	7	2027
Total			$ 186	$ 868	651	1,011		

Virginia Natural Gas

The SAVE program, an accelerated infrastructure replacement program, allows Virginia Natural Gas to continue replacing aging pipeline infrastructure. The program included authorized annual investments of $70 million in each year from 2022 through 2024, with a total potential variance of up to $5 million allowed for the program, for a maximum total investment over the previous six-year term (2019 through 2024) of $365 million.

On June 7, 2024, the Virginia Commission approved the extension of the existing SAVE program through 2029. The extension of the program includes investments of $70 million in each year from 2025 through 2029, with a potential variance of up to $5 million allowed for the program, for a maximum total investment over the five-year extension (2025 through 2029) of $355 million.

The SAVE program is subject to annual review by the Virginia Commission. In accordance with the base rate case approved by the Virginia Commission in 2023, Virginia Natural Gas is recovering program costs incurred prior to January 1, 2023 through base rates. Program costs incurred subsequent to January 1, 2023 are currently being recovered through a separate rider and are subject to future base rate case proceedings. See "Rate Proceedings – Virginia Natural Gas" herein for additional information.

Atlanta Gas Light

In 2019, the Georgia PSC approved the continuation of GRAM as part of Atlanta Gas Light's 2019 rate case order. Various infrastructure programs previously authorized by the Georgia PSC, including the Integrated Vintage Plastic Replacement Program to replace aging plastic pipe and the Integrated System Reinforcement Program to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, continue under GRAM and the recovery of and return on the infrastructure program investments are included in annual base rate adjustments. The amounts to be recovered through rates related to allowed, but not incurred, costs have been quantified as an unrecognized ratemaking amount that is not reflected on the balance sheets. These allowed costs are primarily the equity return on the capital investment under the infrastructure programs in place prior to GRAM and are being recovered through GRAM and base rates until the earlier of the full recovery of such amounts or December 31, 2025. The under recovered balance at December 31, 2024 was $22 million, including $11 million of unrecognized equity return, and is expected to be recovered by December 31, 2025. The Georgia PSC reviews Atlanta Gas Light's performance annually under GRAM. See "Unrecognized Ratemaking Amounts" herein for additional information.

Atlanta Gas Light and the staff of the Georgia PSC previously agreed to a variation of the Integrated Customer Growth Program to extend pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. A separate tariff provides recovery of up to $15 million annually for strategic economic development projects approved by the Georgia PSC.

See "Rate Proceedings – Atlanta Gas Light" herein for additional information regarding the Georgia PSC's 2021 approval of Atlanta Gas Light's GRAM filing and Integrated Capacity and Delivery Plan (i-CDP). The Georgia PSC also approved a new System Reinforcement Rider for authorized large pressure improvement and system reliability projects, which is expected to recover related capital investments totaling $286 million for the years 2022 through 2024, of which $99 million, $104 million, and $76 million was incurred in 2024, 2023, and 2022, respectively.

Chattanooga Gas

In 2021, the Tennessee Public Utilities Commission approved Chattanooga Gas' pipeline replacement program to replace approximately 73 miles of distribution main over a seven-year period. The estimated total cost of the program is $118 million, which will be recovered through Chattanooga Gas' annual base rate review mechanism.

Nicor Gas

Illinois legislation allowed Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system through 2023 and stipulated that rate increases to customers as a result of any infrastructure investments did not exceed a cumulative annual average of 4.0% or, in any given year, 5.5% of base rate revenues. In 2014, the Illinois Commission approved the nine-year regulatory infrastructure program, Investing in Illinois, which concluded in 2023 and is subject to annual review, as

discussed further below. In accordance with orders from the Illinois Commission, Nicor Gas recovered program costs incurred through a separate rider and base rates. See "Rate Proceedings – Nicor Gas" herein for additional information.

In June 2023, the Illinois Commission concluded its review of the Qualifying Infrastructure Plant (QIP) capital investments by Nicor Gas for calendar year 2019 under the QIP rider, also referred to as Investing in Illinois program. The Illinois Commission disallowed $32 million of the $415 million of capital investments commissioned in 2019, together with the related return on investment. Nicor Gas recorded a pre-tax charge to income in the second quarter 2023 of $38 million ($28 million after tax) associated with the disallowance of capital investments placed in service in 2019. The disallowance is reflected on the statement of income as an $8 million reduction to revenues and $30 million in estimated loss on regulatory disallowance. On August 3, 2023, the Illinois Commission denied a rehearing request filed by Nicor Gas. On August 24, 2023, Nicor Gas filed a notice of appeal with the Illinois Appellate Court. On November 25, 2024, the Illinois Appellate Court agreed with the Illinois Commission's review of the QIP capital investments by Nicor Gas for calendar year 2019 under the QIP rider apart from one immaterial item. On December 24, 2024, Nicor Gas filed a petition for leave to appeal $14 million of the 2019 QIP disallowance with the Illinois Supreme Court. Nicor Gas defends these investments in infrastructure as prudently incurred.

The following table provides a summary of QIP capital investments during the nine-year program:

Year	Status of QIP Annual Review Proceeding	Capital Investments	Disallowed	Month of Disallowance
		(in millions)		
2015 – 2018	Complete	$ 1,246	$ —	
2019	Complete[a]	415	32	June 2023
2020	Filed March 2021	402 [b]		
2021	Filed March 2022	392 [b]		
2022	Filed March 2023	408 [b]	6 [c][d]	November 2023
2023	Filed March 2024	365 [b]	25 [c][d]	November 2023
		$ 3,228	$ 63	

(a) Petition for leave to appeal filed to the Illinois Supreme Court for $14 million.

(b) Capital investments are subject to the required QIP annual review proceeding; years 2020 through 2023 are pending with the Illinois Commission.

(c) Appealed to the Illinois Appellate Court.

(d) Disallowed in Nicor Gas' 2023 general base rate case proceeding. See "Rate Proceedings – Nicor Gas" herein for additional information regarding the Illinois Commission's disallowance of certain capital investments.

Any further cost disallowances by the Illinois Commission in the pending cases could be material to the financial statements of Southern Company Gas. The ultimate outcome of these matters cannot be determined at this time.

Natural Gas Cost Recovery

With the exception of Atlanta Gas Light, the natural gas distribution utilities are authorized by the relevant regulatory agencies in the states in which they serve to use natural gas cost recovery mechanisms that adjust rates to reflect changes in the wholesale cost of natural gas and ensure recovery of all costs prudently incurred in purchasing natural gas for customers. The natural gas distribution utilities defer or accrue the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period. The deferred or accrued amount is either billed

or refunded to customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. Natural gas costs generally do not have a significant effect on Southern Company's or Southern Company Gas' net income but could have a significant effect on cash flows. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost through recovery mechanisms approved by the Georgia PSC. At December 31, 2024 and 2023, the over recovered balance was $193 million and $214 million, respectively, which is included in natural gas cost over recovery on Southern Company's and Southern Company Gas' balance sheets.

Rate Proceedings

Nicor Gas

In November 2023, the Illinois Commission approved a $223 million annual base rate increase for Nicor Gas, which became effective December 1, 2023. The base rate increase was based on an ROE of 9.51% and an equity ratio of 50.00%.

In connection with Nicor Gas' 2023 general base rate case proceeding, the Illinois Commission disallowed $126.8 million of capital investments that have been completed or were planned to be completed through December 31, 2024. This includes $31 million for capital investments placed in service in 2022 and 2023 under the Investing in Illinois program and $95.9 million for other transmission and distribution capital investments. Nicor Gas recorded a pre-tax charge to income in the fourth quarter 2023 of $58 million ($44 million after tax) associated with the disallowances, with the remaining $69 million related to prospective projects that will be postponed and/or reevaluated. The disallowance is reflected on the statement of income in estimated loss on regulatory disallowance. See "Infrastructure Replacement Programs and Capital Projects – Nicor Gas" herein for additional information regarding the Illinois Commission's disallowance of certain capital investments. On January 3, 2024, the Illinois Commission denied a request by Nicor Gas for rehearing on the base rate case disallowances associated with capital investment, as well as on other issues determined in the Illinois Commission's November 2023 base rate case decision. On February 6, 2024, Nicor Gas filed a notice of appeal with the Illinois Appellate Court related to the Illinois Commission's rate case ruling.

On January 3, 2025, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $309 million increase in annual base rate revenues. The requested increase is based on a projected test year for the 12-month period ending December 31, 2026, an ROE of 10.35%, and an equity ratio of 54.6%. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective.

The ultimate outcome of these matters cannot be determined at this time.

Atlanta Gas Light

The Georgia PSC evaluates Atlanta Gas Light's earnings against an ROE range of 10.05% to 10.45%, with disposition of any earnings above 10.45% to be determined by the Georgia PSC. Additionally, the Georgia PSC allows inclusion in base rates of the recovery of and return on the infrastructure program investments, including, but not limited to, GRAM adjustments. GRAM filing rate adjustments are based on an authorized ROE of 10.25%. GRAM adjustments for 2021 could not exceed 5% of 2020 base rates. The 5% limitation does not set a precedent in any future rate proceedings by Atlanta Gas Light.

In April 2021, Atlanta Gas Light filed its i-CDP with the Georgia PSC, which included a series of ongoing and proposed pipeline safety, reliability, and growth programs for the next 10 years (2022 through 2031), as well as the required capital investments and related costs to implement the programs. The i-CDP reflected capital investments totaling approximately $0.5 billion to $0.6 billion annually.

In November 2021, the Georgia PSC approved a stipulation between Atlanta Gas Light and the staff of the Georgia PSC, under which, for the years 2022 through 2024, Atlanta Gas Light would incrementally reduce its combined GRAM and System Reinforcement Rider request by 10% through Atlanta Gas Light's GRAM mechanism, which resulted in a reduction of $5 million for 2022, $7 million for 2023, and $9 million for 2024. The stipulation also provided for $1.7 billion of total capital investment for the years 2022 through 2024.

In December 2022 and December 2023, the Georgia PSC approved Atlanta Gas Light's annual GRAM filings, which resulted in annual base rate increases of $53 million effective January 1, 2023 and $53 million effective January 1, 2024, respectively. On December 12, 2024, the Georgia PSC approved Atlanta Gas Light's annual GRAM filing, which included annual base rate increases of $72 million, $73 million, and $74 million effective January 1, 2025, 2026, and 2027, respectively.

On July 2, 2024, the Georgia PSC approved a stipulation related to Atlanta Gas Light's 2024 i-CDP, which included a series of ongoing and proposed pipeline safety, reliability, and growth programs for the next 10 years (2025 through 2034), as well as the required capital investments and related cost to implement the programs. The i-CDP allows capital investments totaling approximately $0.6 billion annually for the years 2025 through 2027 with related revenue requirement recovery through either the

annual GRAM filing or the System Reinforcement Rider surcharge adjustment. Additionally, the Georgia PSC approved a surcharge recovery mechanism for capital projects related to municipal, county, and Georgia Department of Transportation infrastructure work. Rate changes associated with the new surcharge will be based on requests filed annually on September 1. If approved, new rates will become effective January 1 of the following year.

Virginia Natural Gas

In August 2023, the Virginia Commission approved a stipulation related to Virginia Natural Gas' August 2022 general base rate case filing, which allowed for a $48 million increase in annual base rate revenues based on an ROE of 9.70% and an equity ratio of 49.06%. Interim rates became effective as of January 1, 2023, subject to refund, based on Virginia Natural Gas' original requested increase of approximately $69 million. Refunds to customers related to the difference between the approved rates effective September 1, 2023 and the interim rates were completed during the fourth quarter 2023.

On August 1, 2024, Virginia Natural Gas filed a base rate case with the Virginia Commission seeking an increase in annual base revenues of $63 million, including $17 million related to the recovery of investments under the SAVE program, primarily to recover investments and increased costs associated with infrastructure and technology. The requested increase is based on a projected 12-month period beginning January 1, 2025, an ROE of 10.45%, and an equity ratio of 54.92%. Rate adjustments were effective January 1, 2025, subject to refund. The Virginia Commission is expected to issue an order on the requested increase in the fourth quarter 2025. The ultimate outcome of this matter cannot be determined at this time.

Unrecognized Ratemaking Amounts

The following table illustrates Southern Company Gas' authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily comprised of an allowed equity rate of return on assets associated with certain regulatory infrastructure programs. These amounts will be recognized as revenues in Southern Company Gas' financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

	December 31, 2024	December 31, 2023
	(in millions)	
Atlanta Gas Light	**$ 11**	$ 23
Virginia Natural Gas	**10**	10
Chattanooga Gas	**7**	7
Nicor Gas	**—**	3
Total	**$ 28**	$ 43

4. REVENUE FROM CONTRACTS WITH CUSTOMERS

The Registrants generate revenues from a variety of sources, some of which are not accounted for as revenue from contracts with customers, such as leases, derivatives, and certain cost recovery mechanisms. Included in the wholesale electric revenues of the traditional electric operating companies and Southern Power are revenues associated with affiliate transactions. These revenues are generated through long-term PPAs or short-term energy sales made in accordance with the IIC, as approved by the FERC. Amounts related to these affiliate revenues are eliminated in consolidation for Southern Company. See Note 1 under "Affiliate Transactions" and "Revenues" for additional information. See Notes 9 and 14 for additional information on revenue accounted for under lease and derivative accounting guidance, respectively.

The following table disaggregates revenue from contracts with customers for the periods presented:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024						
Operating revenues						
Retail electric revenues						
Residential	$ 8,276	$ 3,133	$ 4,835	$ 308	$ —	$ —
Commercial	6,585	2,042	4,219	324	—	—
Industrial	3,892	1,742	1,808	342	—	—
Other	124	13	102	9	—	—
Total retail electric revenues	18,877	6,930	10,964	983	—	—
Natural gas distribution revenues						
Residential	1,753	—	—	—	—	1,753
Commercial	417	—	—	—	—	417
Transportation	1,295	—	—	—	—	1,295
Industrial	34	—	—	—	—	34
Other	316	—	—	—	—	316
Total natural gas distribution revenues	3,815	—	—	—	—	3,815
Wholesale electric revenues						
PPA energy revenues	1,059	206	94	4	778	—
PPA capacity revenues	641	108	136	63	400	—
Non-PPA revenues	226	139	5	375	230	—
Total wholesale electric revenues	1,926	453	235	442	1,408	—
Other natural gas revenues						
Gas marketing services	507	—	—	—	—	507
Other	18	—	—	—	—	18
Total other natural gas revenues	525	—	—	—	—	525
Other revenues	1,621	240	721	52	37	—
Total revenue from contracts with customers	26,764	7,623	11,920	1,477	1,445	4,340
Other revenue sources[(*)]	(40)	(69)	(589)	(14)	569	116
Total operating revenues	$ 26,724	$ 7,554	$ 11,331	$ 1,463	$ 2,014	$ 4,456
2023						
Operating revenues						
Retail electric revenues						

Residential	$ 7,309	$ 2,904	$ 4,105	$ 300	$ —	$ —
Commercial	5,860	1,928	3,624	308	—	—
Industrial	3,613	1,721	1,558	334	—	—
Other	112	12	91	9	—	—
Total retail electric revenues	16,894	6,565	9,378	951	—	—
Natural gas distribution revenues						
Residential	1,981	—	—	—	—	1,981
Commercial	505	—	—	—	—	505
Transportation	1,184	—	—	—	—	1,184
Industrial	45	—	—	—	—	45
Other	324	—	—	—	—	324
Total natural gas distribution revenues	4,039	—	—	—	—	4,039
Wholesale electric revenues						
PPA energy revenues	1,107	234	87	20	790	—
PPA capacity revenues	624	156	51	45	376	—
Non-PPA revenues	250	65	35	407	409	—
Total wholesale electric revenues	1,981	455	173	472	1,575	—
Other natural gas revenues						
Gas marketing services	528	—	—	—	—	528
Other	31	—	—	—	—	31
Total other natural gas revenues	559	—	—	—	—	559
Other revenues	1,355	213	578	39	55	—
Total revenue from contracts with customers	24,828	7,233	10,129	1,462	1,630	4,598
Other revenue sources(*)	425	(183)	(11)	12	559	104
Total operating revenues	$ 25,253	$ 7,050	$ 10,118	$ 1,474	$ 2,189	$ 4,702
2022						
Operating revenues						
Retail electric revenues						
Residential	$ 6,604	$ 2,638	$ 3,664	$ 302	$ —	$ —
Commercial	5,369	1,685	3,385	299	—	—
Industrial	3,764	1,507	1,921	336	—	—
Other	102	14	79	9	—	—
Total retail electric revenues	15,839	5,844	9,049	946	—	—
Natural gas distribution revenues						
Residential	2,843	—	—	—	—	2,843
Commercial	763	—	—	—	—	763
Transportation	1,186	—	—	—	—	1,186
Industrial	84	—	—	—	—	84
Other	342	—	—	—	—	342
Total natural gas distribution revenues	5,218	—	—	—	—	5,218
Wholesale electric revenues						
PPA energy revenues	2,274	489	130	16	1,673	—
PPA capacity revenues	596	194	47	4	356	—
Non-PPA revenues	250	200	30	690	740	—
Total wholesale electric revenues	3,120	883	207	710	2,769	—
Other natural gas revenues						
Gas marketing services	636	—	—	—	—	636
Other	51	—	—	—	—	51
Total other natural gas revenues	687	—	—	—	—	687
Other revenues	1,077	194	446	47	36	—
Total revenue from contracts with customers	25,941	6,921	9,702	1,703	2,805	5,905
Other revenue sources(*)	3,338	896	1,882	(9)	564	57
Total operating revenues	$ 29,279	$ 7,817	$ 11,584	$ 1,694	$ 3,369	$ 5,962

(*) Other revenue sources relate to revenues from customers accounted for as derivatives and leases, alternative revenue programs at Southern Company Gas, and cost recovery mechanisms and revenues (including those related to fuel costs) that meet other scope exceptions for revenues from contracts with customers at the traditional electric operating companies.

Contract Balances

The following table reflects the closing balances of receivables, contract assets, and contract liabilities related to revenues from contracts with customers at December 31, 2024 and 2023:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Accounts Receivable						
At December 31, 2024	**$ 3,048**	**$ 783**	**$ 1,244**	**$ 113**	**$ 106**	**$ 660**
At December 31, 2023	2,820	821	1,011	90	122	684
Contract Assets						
At December 31, 2024	**$ 323**	**$ 3**	**$ 184**	**$ —**	**$ —**	**$ 72**
At December 31, 2023	271	2	121	—	—	56
Contract Liabilities						
At December 31, 2024	**$ 140**	**$ 11**	**$ 34**	**$ —**	**$ 2**	**$ 3**
At December 31, 2023	116	—	1	—	4	—

Contract assets for Georgia Power primarily relate to retail customer fixed bill programs, where the payment is contingent upon Georgia Power's continued performance and the customer's continued participation in the program over a one-year contract term, and unregulated service agreements, where payment is contingent on project completion. Contract liabilities for Georgia Power primarily relate to cash collections recognized in advance of revenue for unregulated service agreements. Southern Company Gas' contract assets relate to work performed on an energy efficiency enhancement and upgrade contract with the U.S. General Services Administration. Southern Company Gas receives cash advances from a third-party financial institution to fund work performed, of which approximately $68 million had been received at December 31, 2024. These advances have been accounted for as long-term debt on the balance sheets. See Note 1 under "Affiliate Transactions" for additional information regarding the construction contract. At December 31, 2024 and 2023, Southern Company's unregulated distributed generation business had contract assets of $67 million and $91 million, respectively, and contract liabilities of $95 million and $115 million, respectively, for outstanding performance obligations, all of which are expected to be satisfied within one year.

Revenues recognized in 2024 and 2023, which were included in contract liabilities at December 31, 2023 and 2022, respectively, were $98 million and $36 million respectively, for Southern Company and immaterial for the other Registrants. Contract liabilities are primarily classified as current on the balance sheets as the corresponding revenues are generally expected to be recognized within one year.

Remaining Performance Obligations

Southern Company's subsidiaries may enter into long-term contracts with customers in which revenues are recognized as performance obligations are satisfied over the contract term. For the traditional electric operating companies and Southern Power,

these contracts primarily relate to PPAs whereby electricity and generation capacity are provided to a customer. The revenue recognized for the delivery of electricity is variable; however, certain PPAs include a fixed payment for fixed generation capacity over the term of the contract. For Southern Company Gas, these contracts primarily relate to the U.S. General Services Administration contract described above. Southern Company's unregulated distributed generation business also has partially satisfied performance obligations related to certain fixed price contracts. Revenues from contracts with customers related to these performance obligations remaining at December 31, 2024 are expected to be recognized as follows:

	2025	2026	2027	2028	2029	Thereafter
			(in millions)			
Southern Company	$ 937	$ 427	$ 371	$ 343	$ 309	$ 2,636
Alabama Power	11	—	—	—	—	—
Georgia Power	69	30	15	16	2	27
Mississippi Power(*)	63	66	69	73	—	—
Southern Power(*)	340	331	340	316	312	2,609
Southern Company Gas	2	—	—	—	—	—

(*) Includes performance obligations related to affiliate PPAs with Georgia Power. See Note 1 under "Affiliate Transactions" for additional information.

5. PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment is stated at original cost or fair value at acquisition, as appropriate, less any regulatory disallowances and impairments. Original cost may include: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of equity funds used during construction.

The Registrants' property, plant, and equipment in service consisted of the following at December 31, 2024 and 2023:

At December 31, 2024:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	**$ 61,292**	**$ 16,801**	**$ 26,089**	**$ 2,946**	**$ 14,920**	**$ —**
Transmission	**16,280**	**6,449**	**8,800**	**989**	**—**	**—**
Distribution	**28,678**	**10,373**	**16,887**	**1,418**	**—**	**—**
General/other	**6,547**	**2,878**	**3,260**	**344**	**41**	**—**
Electric utilities' plant in service	**112,797**	**36,501**	**55,036**	**5,697**	**14,961**	**—**
Southern Company Gas:						
Natural gas transportation and distribution	**18,896**	**—**	**—**	**—**	**—**	**18,896**
Storage facilities	**1,748**	**—**	**—**	**—**	**—**	**1,748**
Other	**1,694**	**—**	**—**	**—**	**—**	**1,694**
Southern Company Gas plant in service	**22,338**	**—**	**—**	**—**	**—**	**22,338**
Other plant in service	**2,008**	**—**	**—**	**—**	**—**	**—**
Total plant in service	**$ 137,143**	**$ 36,501**	**$ 55,036**	**$ 5,697**	**$ 14,961**	**$ 22,338**

At December 31, 2023:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	$ 57,325	$ 16,584	$ 22,587	$ 2,909	$ 14,649	$ —
Transmission	15,561	6,152	8,402	966	—	—
Distribution	26,482	9,775	15,380	1,327	—	—
General/other	6,305	2,918	3,001	321	41	—
Electric utilities' plant in service	105,673	35,429	49,370	5,523	14,690	—
Southern Company Gas:						
Natural gas transportation and distribution	17,798	—	—	—	—	17,798
Storage facilities	1,565	—	—	—	—	1,565
Other	1,477	—	—	—	—	1,477
Southern Company Gas plant in service	20,840	—	—	—	—	20,840
Other plant in service	1,915	—	—	—	—	—
Total plant in service	$ 128,428	$ 35,429	$ 49,370	$ 5,523	$ 14,690	$ 20,840

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs and certain maintenance costs including those described below.

In accordance with orders from their respective state PSCs, Alabama Power and Georgia Power defer nuclear refueling outage operations and maintenance expenses to a regulatory asset when the charges are incurred. Alabama Power amortizes the costs over a subsequent 18-month period with Plant Farley's fall outage cost amortization beginning in January of the following year and spring outage cost amortization beginning in July of the same year. Georgia Power amortizes its costs over each unit's operating cycle, or 18 months for Plant Vogtle Units 1 through 4 and 24 months for Plant Hatch Units 1 and 2. Georgia Power's amortization period begins the month the refueling outage starts.

The portion of Southern Company Gas' non-working gas used to maintain the structural integrity of natural gas storage facilities that is considered to be non-recoverable is depreciated, while the recoverable or retained portion is not depreciated.

See Note 9 for information on finance lease right-of-use (ROU) assets, net, which are included in property, plant, and equipment.

The Registrants have deferred certain implementation costs related to cloud hosting arrangements. At December 31, 2024 and 2023, deferred cloud implementation costs, net of amortization, which are generally included in other deferred charges and assets on the Registrants' balance sheets, were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred cloud implementation costs, net:						
At December 31, 2024	**$ 321**	**$ 92**	**$ 111**	**$ 13**	**$ 12**	**$ 35**
At December 31, 2023	325	85	99	13	15	43

Once a hosted software is placed into service, the related deferred costs are amortized on a straight-line basis over the remaining expected hosting arrangement term, including any renewal options that are reasonably certain of exercise. The amortization is reflected with the associated cloud hosting fees, which are generally reflected in other operations and maintenance expenses on

the Registrants' statements of income. Amortization of deferred cloud implementation costs recognized in 2024, 2023, and 2022 was immaterial for Mississippi Power, Southern Power, and Southern Company Gas and was as follows for the other Registrants:

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
2024	**$ 56**	**$ 17**	**$ 22**
2023	46	11	19
2022	29	8	12

See Note 2 under "Regulatory Assets and Liabilities" for information on deferrals of certain other operations and maintenance costs associated with software and cloud computing projects by the traditional electric operating companies and natural gas distribution utilities, as authorized by their respective state PSCs or applicable state regulatory agencies.

Depreciation and Amortization

The traditional electric operating companies' and Southern Company Gas' depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates. The approximate rates for 2024, 2023, and 2022 were as follows:

	2024	2023	2022
Alabama Power	**4.2 %**	4.1 %	2.7 %
Georgia Power	**3.4 %**	3.8 %	3.3 %
Mississippi Power	**3.3 %**	3.4 %	3.4 %
Southern Company Gas	**2.9 %**	2.7 %	2.7 %

Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and/or other applicable state and federal regulatory agencies for the traditional electric operating companies and the natural gas distribution utilities. Effective January 1, 2023, Alabama Power's and Georgia Power's depreciation rates were revised. On October 25, 2024, Mississippi Power filed an updated depreciation study with the Mississippi PSC requesting an $11 million increase in total annual depreciation. On February 13, 2025, Mississippi Power entered into a stipulation with the MPUS to include certain modifications to the interim net salvage rates and increases to certain service lives. The stipulation requests an $8 million increase in total annual depreciation. The ultimate outcome of this matter cannot be determined at this time. See Note 2 for additional information.

When property, plant, and equipment subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the asset are retired when the related property unit is retired.

At December 31, 2024 and 2023, accumulated depreciation for Southern Company and Southern Company Gas consisted of utility plant in service totaling $38.9 billion and $36.6 billion, respectively, for Southern Company and $5.6 billion and $5.3 billion, respectively, for Southern Company Gas, as well as other plant in service totaling $1.2 billion and $1.1 billion, respectively, for Southern Company and $252 million and $210 million, respectively, for Southern Company Gas. Other plant in service includes the non-utility assets of Southern Company Gas, as well as, for Southern Company, certain other non-utility subsidiaries. Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives. Useful lives for Southern Company Gas's non-utility assets range from five to 10 years for transportation equipment, five to 40 years for storage facilities, and up to 78 years for other assets. Useful lives for the assets of Southern Company's other non-utility subsidiaries range up to 40 years.

Southern Power

Southern Power applies component depreciation, where depreciation is computed principally by the straight-line method over the estimated useful life of the asset. Certain of Southern Power's generation assets related to natural gas-fired facilities are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of, and revenues from, these assets. The primary assets in Southern Power's property, plant, and equipment are generating facilities, which generally have estimated useful lives as follows:

Southern Power Generating Facility	Useful life
Natural gas	Up to 50 years
Solar	Up to 35 years
Wind	Up to 35 years

When Southern Power's depreciable property, plant, and equipment is retired, or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed and a gain or loss is recognized in the statements of income. Southern Power reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on Southern Power's net income.

Joint Ownership Agreements

At December 31, 2024, the Registrants' percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Alabama Power				
Plant Greene County (natural gas) Units 1 and 2	60.0 % [a]	$ 192	$ 140	$ 1
Plant Miller (coal) Units 1 and 2	91.8 [b]	2,180	829	7
Georgia Power				
Plant Hatch (nuclear) Units 1 and 2	50.1 % [c]	$ 1,464	$ 604	$ 66
Plant Vogtle (nuclear) Units 1 and 2	45.7 [c]	3,621	2,342	162
Plant Vogtle (nuclear) Units 3 and 4	45.7 [c]	7,953	119	45
Plant Scherer (coal) Units 1 and 2	8.4 [c]	289	140	4
Plant Scherer (coal) Unit 3	75.0 [c]	1,316	720	22
Rocky Mountain (pumped storage)	25.4 [d]	182	160	6
Mississippi Power				
Plant Greene County (natural gas) Units 1 and 2	40.0 % [a]	$ 125	$ 88	$ 2
Plant Daniel (coal) Units 1 and 2	50.0 [e]	791	286	3
Southern Company Gas				
Dalton Pipeline (natural gas pipeline)	50.0 % [f]	$ 271	$ 32	$ 1

(a) Jointly owned by Alabama Power and Mississippi Power and operated and maintained by Alabama Power.

(b) Jointly owned with PowerSouth and operated and maintained by Alabama Power.

(c) Georgia Power owns undivided interests in Plants Hatch, Vogtle, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, FP&L, and Jacksonville Electric Authority. Georgia Power has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third-party claims related to these plants.

(d) Jointly owned with OPC, which is the operator of the plant.

(e) Jointly owned with FP&L. In accordance with the operating agreement, Mississippi Power acts as FP&L's agent with respect to the operation and maintenance of these units. See Note 2 under "Mississippi Power – Plant Daniel" for information on Mississippi Power's agreement with FP&L to acquire FP&L's 50% ownership interest in Plant Daniel Units 1 and 2.

(f) Jointly owned with The Williams Companies, Inc., the Dalton Pipeline is a 115-mile natural gas pipeline that serves as an extension of the Transcontinental Gas Pipe Line Company, LLC pipeline system into northwest Georgia. Southern Company Gas leases its 50% undivided ownership for approximately $26 million annually through 2042. The lessee is responsible for maintaining the pipeline during the lease term and for providing service to transportation customers under its FERC-regulated tariff.

The Registrants' proportionate share of their jointly-owned facility operating expenses is included in the corresponding operating expenses in the statements of income and each Registrant is responsible for providing its own financing.

Assets Subject to Lien

Mississippi Power provides retail service to its largest retail customer, Chevron Products Company (Chevron), at its refinery in Pascagoula, Mississippi through at least 2038 in accordance with agreements approved by the Mississippi PSC. The agreements grant Chevron a security interest in the co-generation assets located at the refinery and owned by Mississippi Power, with a lease receivable balance of $139 million at December 31, 2024, that is exercisable upon the occurrence of (i) certain bankruptcy events or (ii) other events of default coupled with specific reductions in steam output at the facility and a downgrade of Mississippi Power's credit rating to below investment grade by two of the three rating agencies. See Note 9 under "Lessor" for additional information.

See Note 8 under "Long-term Debt" for information regarding debt secured by certain assets of Georgia Power and Southern Company Gas.

6. ASSET RETIREMENT OBLIGATIONS

AROs are computed as the present value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. Each traditional electric operating company and natural gas distribution utility has received accounting guidance from its state PSC or applicable state regulatory agency allowing the continued accrual or recovery of other retirement costs for long-lived assets that it does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as regulatory liabilities and amounts to be recovered are reflected in the balance sheets as regulatory assets.

The ARO liabilities for the traditional electric operating companies primarily relate to facilities that are subject to the CCR Rule and the related state rules, principally surface impoundments. In addition, Alabama Power and Georgia Power have retirement obligations related to the decommissioning of nuclear facilities (Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle). See "Nuclear Decommissioning" herein for additional information. Other significant AROs include various landfill sites and asbestos removal for Alabama Power, Georgia Power, and Mississippi Power and gypsum cells and mine reclamation for Mississippi Power. The ARO liability for Southern Power primarily relates to its solar and wind facilities, which are located on long-term land leases requiring the restoration of land at the end of the lease.

The traditional electric operating companies and Southern Company Gas also have identified other retirement obligations, such as obligations related to certain electric transmission and distribution facilities, certain asbestos-containing material within long-term assets not subject to ongoing repair and maintenance activities, certain wireless communication towers, the disposal of polychlorinated biphenyls in certain transformers, leasehold improvements, equipment on customer property, and property

associated with the Southern Company system's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for certain retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

Southern Company and the traditional electric operating companies will continue to recognize in their respective statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the various state PSCs.

Details of the AROs included in the balance sheets are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power(*)
			(in millions)		
Balance at December 31, 2022	$ 10,840	$ 4,287	$ 6,034	$ 179	$ 144
Liabilities incurred	90	—	90	—	—
Liabilities settled	(617)	(270)	(304)	(18)	—
Accretion expense	403	156	230	5	6
Cash flow revisions	(399)	(15)	(385)	2	—
Balance at December 31, 2023	$ 10,317	$ 4,158	$ 5,665	$ 168	$ 150
Liabilities incurred	**130**	**8**	**120**	**—**	**2**
Liabilities settled	**(566)**	**(254)**	**(270)**	**(17)**	**—**
Accretion expense	**400**	**153**	**232**	**5**	**7**
Cash flow revisions	**(347)**	**(7)**	**(332)**	**(8)**	—
Balance at December 31, 2024	**$ 9,934**	**$ 4,058**	**$ 5,415**	**$ 148**	**$ 159**

(*) Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

In June 2023, Alabama Power completed an updated decommissioning cost site study for Plant Farley. The estimated cost of decommissioning based on the study resulted in a decrease in Alabama Power's ARO liability of approximately $15 million. See "Nuclear Decommissioning" herein for additional information.

Following initial criticality for Plant Vogtle Unit 3 and 4 on March 6, 2023 and February 14, 2024, respectively, Georgia Power recorded AROs of approximately $90 million and $118 million, respectively. See "Nuclear Decommissioning" herein and Note 2 under "Georgia Power – Nuclear Construction" for additional information.

In September 2023 and November 2023, Georgia Power recorded net decreases of approximately $175 million and $210 million, respectively, to its AROs related to the CCR Rule and the related state rule resulting from changes in estimates, including lower future inflation rates and the timing of closure activities.

In September 2024, Georgia Power completed updated decommissioning cost site studies for Plants Hatch and Vogtle Units 1 through 4. The estimated cost of decommissioning based on the studies resulted in a decrease in Georgia Power's ARO liability of $389 million. See "Nuclear Decommissioning" herein for additional information.

In November 2024, Georgia Power recorded a net increase of approximately $60 million to its AROs related to the CCR Rule and the related state rule resulting from changes in estimates, including higher future inflation rates and the timing of closure activities.

The cost estimates for AROs related to the disposal of CCR are based on information at December 31, 2024 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule and the related state rules. The traditional electric operating companies have periodically updated, and expect to continue periodically updating, their related cost estimates and ARO liabilities for each CCR unit as additional information related to these assumptions becomes available. Some of these updates have been, and future

updates may be, material. The cost estimates for Alabama Power are based on closure-in-place for all surface impoundments. The cost estimates for Georgia Power and Mississippi Power are based on a combination of closure-in-place for some surface impoundments and closure by removal for others. Additionally, the closure designs and plans in the States of Alabama and Georgia are subject to approval by environmental regulatory agencies. Absent continued recovery of ARO costs through regulated rates, results of operations, cash flows, and financial condition for Southern Company and the traditional electric operating companies could be materially impacted. The ultimate outcome of these matters cannot be determined at this time. See Note 3 under "General Litigation Matters – Alabama Power" for additional information.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third-party managers with oversight by the management of Alabama Power and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

Alabama Power and Georgia Power record the investment securities held in the Funds at fair value, as disclosed in Note 13, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

Investment securities in the Funds at December 31, 2024 and 2023 were as follows:

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
At December 31, 2024:			
Equity securities	**$ 1,413**	**$ 848**	**$ 565**
Debt securities	**976**	**335**	**641**
Other securities	**232**	**202**	**30**
Total investment securities in the Funds	**$ 2,621**	**$ 1,385**	**$ 1,236**
At December 31, 2023:			
Equity securities	$ 1,288	$ 796	$ 492
Debt securities	895	277	618
Other securities	239	186	53
Total investment securities in the Funds	$ 2,422	$ 1,259	$ 1,163

These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

The fair value increases (decreases) of the Funds, including unrealized gains (losses) and reinvested interest and dividends and excluding the Funds' expenses, for 2024, 2023, and 2022 are shown in the table below.

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
Fair value increases (decreases)			
2024	**$ 229**	**$ 143**	**$ 86**
2023	281	157	124
2022	(360)	(171)	(189)
Unrealized gains (losses)			
At December 31, 2024	**$ 113**	**$ 64**	**$ 49**
At December 31, 2023	241	119	122
At December 31, 2022	(391)	(204)	(187)

The investment securities held in the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, approximately $12 million and $13 million at December 31, 2024 and 2023, respectively, previously recorded in internal reserves is being transferred into the Funds through 2040 as approved by the Alabama PSC.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2024 and 2023, the accumulated provisions for the external decommissioning trust funds were as follows:

	2024	2023
	(in millions)	
Alabama Power		
Plant Farley	**$ 1,385**	$ 1,259
Georgia Power		
Plant Hatch	**$ 735**	$ 705
Plant Vogtle Units 1 and 2	**460**	434
Plant Vogtle Units 3 and 4	**41**	24
Total	**$ 1,236**	$ 1,163

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on removal of the plant from service and prompt dismantlement. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning at December 31, 2024 based on the most current studies were as follows:

	Alabama Power	Georgia Power		
	Plant Farley	Plant Hatch(*)	Plant Vogtle Units 1 and 2(*)	Plant Vogtle Unit 3 and 4(*)
Most current study year	2023	2024	2024	2024
Decommissioning periods:				
Beginning year	2037	2034	2047	2062
Completion year	2087	2088	2092	2074
		(in millions)		
Site study costs:				
Radiated structures	$ 1,402	$ 795	$ 674	$ 599
Spent fuel management	513	306	255	88
Non-radiated structures	133	77	107	89
Total site study costs	$ 2,048	$ 1,178	$ 1,036	$ 776

(*) Based on Georgia Power's ownership interests.

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management. Significant assumptions used to determine these costs for ratemaking were an estimated inflation rate of 4.5% for Plant Farley, 2.5% for Plants Hatch and Vogtle Units 1 and 2, and 2.3% for Plant Vogtle Units 3 and 4 and an estimated trust earnings rate of 7.0% for Plant Farley, 4.5% for Plants Hatch and Vogtle Units 1 and 2, and 4.3% for Plant Vogtle Units 3 and 4.

Amounts previously contributed to the Funds for Plant Farley are currently projected to be adequate to meet the decommissioning obligations. Alabama Power's site-specific estimates of decommissioning costs for Plant Farley are updated every five years. The next site study for Alabama Power is expected to be completed in 2028. Projections of funds are reviewed with the Alabama PSC to ensure that, over time, the deposits and earnings of the Funds will provide adequate funding to cover the site-specific costs. If necessary, Alabama Power would seek the Alabama PSC's approval to address any changes in a manner consistent with NRC and other applicable requirements.

Under the 2019 ARP, Georgia Power's annual decommissioning cost for ratemaking in 2022 was a total of $4 million for Plant Hatch and Plant Vogtle Units 1 and 2. Effective January 1, 2023, as approved in the 2022 ARP, there is no annual decommissioning cost for ratemaking for Plant Hatch and Plant Vogtle Units 1 and 2. Any funding amount required by the NRC during the period covered by the 2022 ARP will be deferred to a regulatory asset and recovery is expected to be determined in Georgia Power's next base rate case. See Note 2 under "Georgia Power – Rate Plans – 2022 ARP" for additional information. Effective August 1, 2023, as approved under the Plant Vogtle Unit 3 and Common Facilities rate proceeding, Georgia Power's annual decommissioning cost for ratemaking is $8 million for Plant Vogtle Unit 3. Effective May 1, 2024, as approved under the Prudency Stipulation, Georgia Power's annual decommissioning cost for ratemaking is $8 million for Plant Vogtle Unit 4. See Note 2 under "Georgia Power – Nuclear Construction – Regulatory Matters" for additional information.

7. CONSOLIDATED ENTITIES AND EQUITY METHOD INVESTMENTS

The Registrants may hold ownership interests in a number of business ventures with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE. If a venture is a VIE for which a Registrant is the primary beneficiary, the assets, liabilities, and results of operations of the entity are consolidated. The Registrants reassess the conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events.

For entities that are not determined to be VIEs, the Registrants evaluate whether they have control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under the control of a Registrant are

consolidated, and entities over which a Registrant can exert significant influence, but which a Registrant does not control, are accounted for under the equity method of accounting.

Investments accounted for under the equity method are recorded within equity investments in unconsolidated subsidiaries in the balance sheets and, for Southern Company and Southern Company Gas, the equity income is recorded within earnings from equity method investments in the statements of income. See "SEGCO" and "Southern Company Gas" herein for additional information.

Southern Company

At December 31, 2024 and 2023, Southern Holdings had equity method investments totaling $128 million and $126 million, respectively, primarily related to investments in venture capital funds focused on energy and utility investments. Earnings/losses from these investments were immaterial for all periods presented.

SEGCO

Alabama Power and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units at Plant Gaston with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. Retirement of SEGCO's generating units is currently expected to occur by December 31, 2028. However, Alabama Power, in conjunction with Georgia Power, is evaluating extending the operation of Plant Gaston Units 1 through 4 beyond the indicated retirement date. See Note 2 under "Georgia Power – Integrated Resource Plans – 2025 IRP" for additional information. Alabama Power and Georgia Power account for SEGCO using the equity method; Southern Company consolidates SEGCO. The capacity of these units is sold equally to Alabama Power and Georgia Power. Alabama Power and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and an ROE. The share of purchased power included in purchased power, affiliates in the statements of income totaled $115 million in 2024, $112 million in 2023, and $124 million in 2022 for Alabama Power and $118 million in 2024, $115 million in 2023, and $127 million in 2022 for Georgia Power.

SEGCO paid dividends of $20 million in 2024, $25 million in 2023, and $14 million in 2022, one half of which were paid to each of Alabama Power and Georgia Power. In addition, Alabama Power and Georgia Power each recognize 50% of SEGCO's net income.

Alabama Power, which owns and operates a generating unit adjacent to the SEGCO generating units, has a joint ownership agreement with SEGCO for the ownership of an associated gas pipeline. Alabama Power owns 14% of the pipeline with the remaining 86% owned by SEGCO.

See Note 3 under "Guarantees" for additional information regarding guarantees of Alabama Power and Georgia Power related to SEGCO.

Southern Power

Variable Interest Entities

Southern Power has certain subsidiaries that are determined to be VIEs. Southern Power is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

SP Solar and SP Wind

SP Solar is owned by Southern Power and a limited partner. A wholly-owned subsidiary of Southern Power is the general partner and holds a 1% ownership interest, and another wholly-owned subsidiary of Southern Power owns a 66% ownership interest. The limited partner holds the remaining 33% noncontrolling interest. SP Solar qualifies as a VIE since the arrangement is structured as a limited partnership and the 33% limited partner does not have substantive kick-out rights against the general partner.

At December 31, 2024 and 2023, SP Solar had total assets of $5.4 billion and $5.6 billion, respectively, total liabilities of $372 million and $399 million, respectively, and noncontrolling interests of $1.0 billion. Cash distributions from SP Solar are allocated 67% to Southern Power and 33% to the limited partner in accordance with their partnership interest percentage. Under the terms of the limited partnership agreement, distributions without limited partner consent are limited to available cash and SP Solar is

obligated to distribute all such available cash to its partners each quarter. Available cash includes all cash generated in the quarter subject to the maintenance of appropriate operating reserves.

SP Wind is owned by Southern Power and three financial investors. A wholly-owned subsidiary of Southern Power owns 100% of the Class B membership interests and the three financial investors own 100% of the Class A membership interests. SP Wind qualifies as a VIE since the structure of the arrangement is similar to a limited partnership and the Class A members do not have substantive kick-out rights against Southern Power.

At December 31, 2024 and 2023, SP Wind had total assets of $2.0 billion and $2.1 billion, respectively, total liabilities of $177 million and $187 million, respectively, and noncontrolling interests of $35 million and $38 million, respectively. Under the terms of the limited liability agreement, distributions without Class A member consent are limited to available cash and SP Wind is obligated to distribute all such available cash to its members each quarter. Available cash includes all cash generated in the quarter subject to the maintenance of appropriate operating reserves. Cash distributions from SP Wind are generally allocated 60% to Southern Power and 40% to the three financial investors in accordance with the limited liability agreement.

Southern Power consolidates both SP Solar and SP Wind, as the primary beneficiary, since it controls the most significant activities of each entity, including operating and maintaining their assets. Certain transfers and sales of the assets in the VIEs are subject to partner consent and the liabilities are non-recourse to the general credit of Southern Power. Liabilities consist of customary working capital items and do not include any long-term debt.

Other Variable Interest Entities

Southern Power has other consolidated VIEs that relate to certain subsidiaries that have either sold noncontrolling interests to tax equity investors or acquired less than a 100% interest from facility developers. These entities are considered VIEs because the arrangements are structured similar to a limited partnership and the noncontrolling members do not have substantive kick-out rights.

At December 31, 2024 and 2023, the other VIEs had total assets of $1.6 billion and $1.7 billion, respectively, total liabilities of $224 million and $230 million, respectively, and noncontrolling interests of $691 million and 761 million, respectively. Under the terms of the partnership agreements, distributions of all available cash are required each month or quarter and additional distributions require partner consent.

Equity Method Investments

During 2023 and 2022, Southern Power sold its remaining equity method investments in wind projects and received proceeds totaling $50 million and $38 million, respectively. Earnings (loss) from these investments, including the gains associated with the sales, were immaterial for 2023 and 2022.

Southern Company Gas

The carrying amounts of Southern Company Gas' equity method investments at December 31, 2024 and 2023 were as follows:

Investment Balance	December 31, 2024	December 31, 2023
	(in millions)	
SNG	**$ 1,245**	$ 1,202
Other	**34**	33
Total	**$ 1,279**	$ 1,235

The earnings from Southern Company Gas' equity method investment related to SNG were $146 million in 2024, $139 million in 2023, and $146 million in 2022. The earnings from Southern Company Gas' other equity method investments were immaterial for all periods presented.

8. FINANCING

Long-term Debt

Details of long-term debt at December 31, 2024 and 2023 are provided in the following table:

	At December 31, 2024		Balance Outstanding at December 31,	
	Maturity	Weighted Average Interest Rate	2024	2023
			(in millions)	
Southern Company				
Senior notes[a]	2025-2074	4.33%	**$ 44,862**	$ 40,235
Junior subordinated notes	2027-2081	4.32%	**7,389**	8,333
FFB loans[b]	2025-2044	2.88%	**4,703**	4,788
Revenue bonds[c]	2025-2063	3.15%	**3,379**	3,400
First mortgage bonds[d]	2025-2064	3.79%	**2,775**	2,500
Medium-term notes	2026-2027	7.03%	**84**	84
Other long-term debt	2025-2045	4.96%	**209**	234
Finance lease obligations[e]			**287**	298
Unamortized fair value adjustment			**275**	302
Unamortized debt premium (discount), net			**(58)**	(198)
Unamortized debt issuance expenses			**(419)**	(290)
Total long-term debt			**63,486**	59,686
Less: Amount due within one year			**4,718**	2,476
Total long-term debt excluding amount due within one year			**$ 58,768**	$ 57,210
Alabama Power				
Senior notes	2025-2073	3.94%	**$ 9,875**	$ 9,875
Revenue bonds[c]	2025-2063	3.11%	**1,300**	1,321
Other long-term debt	2026-2030	6.11%	**61**	75
Finance lease obligations[e]			**4**	5
Unamortized debt premium (discount), net			**(19)**	(20)
Unamortized debt issuance expenses			**(67)**	(73)
Total long-term debt			**11,154**	11,183
Less: Amount due within one year			**655**	223
Total long-term debt excluding amount due within one year			**$ 10,499**	$ 10,960
Georgia Power				
Senior notes	2025-2074	4.49%	**$ 11,292**	$ 9,575
Junior subordinated notes	2077	5.00%	**270**	270
FFB loans[b]	2025-2044	2.88%	**4,703**	4,788
Revenue bonds[c]	2025-2062	3.18%	**1,968**	1,968
Finance lease obligations[e]			**261**	240
Unamortized debt premium (discount), net			**(21)**	(19)
Unamortized debt issuance expenses			**(123)**	(122)
Total long-term debt			**18,350**	16,700
Less: Amount due within one year			**966**	502
Total long-term debt excluding amount due within one year			**$ 17,384**	$ 16,198
Mississippi Power				
Senior notes	2026-2054	4.33%	**$ 1,575**	$ 1,525
Revenue bonds[c]	2025-2052	3.16%	**111**	111
Finance lease obligations[e]			**14**	16
Unamortized debt premium (discount), net			**2**	1
Unamortized debt issuance expenses			**(9)**	(9)

Total long-term debt			**1,693**	1,644
Less: Amount due within one year			**12**	201
Total long-term debt excluding amount due within one year			**$ 1,681**	$ 1,443
Southern Power				
Senior notes[a]	2025-2046	4.05%	**$ 2,695**	$ 2,728
Unamortized debt premium (discount), net			**(4)**	(4)
Unamortized debt issuance expenses			**(11)**	(13)
Total long-term debt			**2,680**	2,711
Less: Amount due within one year			**500**	—
Total long-term debt excluding amount due within one year			**$ 2,180**	$ 2,711
Southern Company Gas				
Senior notes	2025-2051	4.41%	**$ 5,375**	$ 4,930
First mortgage bonds[d]	2025-2064	3.79%	**2,775**	2,500
Medium-term notes	2026-2027	7.03%	**84**	84
Other long-term debt	2025-2045	3.81%	**68**	59
Unamortized fair value adjustment			**275**	302
Unamortized debt premium (discount), net			**(9)**	(8)
Unamortized debt issuance expenses			**(37)**	(34)
Total long-term debt			**8,531**	7,833
Less: Amount due within one year			**302**	—
Total long-term debt excluding amount due within one year			**$ 8,229**	$ 7,833

(a) Includes a fair value gain (loss) of $(45) million and $(12) million at December 31, 2024 and 2023, respectively, related to Southern Power's foreign currency hedge on its euro-denominated senior notes.

(b) Secured by a first priority lien on (i) Georgia Power's undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. See "DOE Loan Guarantee Borrowings" herein for additional information.

(c) Revenue bond obligations represent loans to the traditional electric operating companies from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal and wastewater facilities. In some cases, the revenue bond obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of revenue bonds issued by public authorities. The traditional electric operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

(d) Secured by substantially all of Nicor Gas' properties.

(e) Secured by the underlying lease ROU asset. See Note 9 for additional information.

Maturities of long-term debt for the next five years are as follows:

	Southern Company[a]	Alabama Power[b]	Georgia Power[c]	Mississippi Power	Southern Power[d]	Southern Company Gas
			(in millions)			
2025	$ 4,727	$ 658	$ 967	$ 12	$ 500	$ 300
2026	3,792	47	451	66	964	530
2027	4,075	551	1,015	10	—	154
2028	2,827	107	868	357	—	150
2029	1,990	—	861	1	—	150

(a) See notes (b), (c), and (d) below.

(b) Alabama Power's 2025 maturities include $200 million aggregate principal amount of Series 2023A Floating Rate Senior Notes due May 15, 2073 that are repayable at the option of the holders at certain dates that began in 2024. As a result, the senior notes are classified as securities due within one year on the balance sheets of Southern Company and Alabama Power at December 31, 2024.

(c) Amounts include principal amortization related to the FFB borrowings; however, the final maturity date is February 20, 2044. See "DOE Loan Guarantee Borrowings" herein for additional information. Georgia Power's 2025 maturities include approximately $117 million aggregate principal amount of Series 2024C Floating Rate Senior Notes due November 15, 2074 that are repayable at the option of the holders at certain dates beginning in 2025. As a result, the senior notes are classified as securities due within one year on the balance sheets of Southern Company and Georgia Power at December 31, 2024.

(d) Southern Power's 2026 maturities include $564 million of euro-denominated debt at the U.S. dollar-denominated hedge settlement amount.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement in 2014 and the Amended and Restated Loan Guarantee Agreement in 2019. Under the Amended and Restated Loan Guarantee Agreement, the DOE agreed to guarantee the obligations of Georgia Power under the FFB Credit Facilities. Under the FFB Credit Facilities, Georgia Power was authorized to make term loan borrowings through the FFB in an amount up to approximately $5.130 billion.

In 2021, Georgia Power made the final borrowings under the FFB Credit Facilities and no further borrowings are permitted. During 2024, Georgia Power made principal amortization payments of $86 million under the FFB Credit Facilities. At December 31, 2024 and 2023, Georgia Power had $4.7 billion and $4.8 billion of borrowings outstanding under the FFB Credit Facilities, respectively.

All borrowings under the FFB Credit Facilities are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under its guarantee. Georgia Power's reimbursement obligations to the DOE are secured by a first priority lien on (i) Georgia Power's undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

The final maturity date for each advance under the FFB Credit Facilities is February 20, 2044. Interest is payable quarterly and principal payments began in 2020. Each borrowing under the FFB Credit Facilities bears interest at a fixed rate equal to the applicable U.S. Treasury rate at the time of the borrowing plus a spread equal to 0.375%.

Under the Amended and Restated Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facilities over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) loss of necessary governmental approvals for operation of Plant Vogtle Units 3 and 4; (ii) loss of regulation by the Georgia PSC; (iii) cost disallowances by the Georgia PSC that could have a material adverse effect on Georgia Power's ability to repay the outstanding borrowings under the FFB Credit Facilities; (iv) certain material casualty losses or a governmental taking of Plant Vogtle Units 3 and 4; or (v) loss of access to the intellectual property rights necessary to operate Plant Vogtle Units 3 and 4. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facilities. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facilities. Under the FFB Credit Facilities, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

Secured Debt

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

As discussed under "Long-term Debt" herein, the Registrants had secured debt outstanding at December 31, 2024 and 2023. Each Registrant's senior notes, junior subordinated notes, revenue bond obligations, bank term loans, credit facility borrowings, and notes payable are effectively subordinated to all secured debt of each respective Registrant.

Equity Units

In May 2022, Southern Company remarketed $862.5 million aggregate principal amount of its Series 2019A Remarketable Junior Subordinated Notes due August 1, 2024 (2019A RSNs) and $862.5 million aggregate principal amount of its Series 2019B

Remarketable Junior Subordinated Notes due August 1, 2027 (2019B RSNs), pursuant to the terms of its 2019 Series A Equity Units (Equity Units). In connection with the remarketing, the interest rates on the 2019A RSNs and the 2019B RSNs were reset to 4.475% and 5.113%, respectively, payable on a semi-annual basis. In August 2022, the proceeds were ultimately used to settle the purchase contracts entered into as part of the Equity Units and Southern Company issued approximately 25.2 million shares of common stock and received proceeds of $1.725 billion. In August 2024, Southern Company repaid at maturity the $862.5 million 2019A RSNs. At December 31, 2023, the 2019A RSNs were included on Southern Company's consolidated balance sheet in securities due within one year. At December 31, 2024 and 2023, the 2019B RSNs were included on Southern Company's consolidated balance sheets in long-term debt.

Convertible Senior Notes

In May 2024, Southern Company issued $1.5 billion aggregate principal amount of Series 2024A 4.50% Convertible Senior Notes due June 15, 2027 (Series 2024A Convertible Senior Notes).

In February 2023, Southern Company issued $1.5 billion aggregate principal amount of Series 2023A 3.875% Convertible Senior Notes due December 15, 2025 (Series 2023A Convertible Senior Notes). In March 2023, Southern Company issued an additional $225 million aggregate principal amount of the Series 2023A Convertible Senior Notes upon the exercise by the initial purchasers of their over-allotment option.

Interest on the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes is payable semiannually. The Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes will mature on June 15, 2027 and December 15, 2025, respectively, unless earlier converted or repurchased, but are not redeemable at the option of Southern Company. Both the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes are direct, unsecured, and unsubordinated obligations of Southern Company, ranking equally with all of Southern Company's other unsecured and unsubordinated indebtedness from time to time outstanding, and are effectively subordinated to all secured indebtedness of Southern Company.

Under the following circumstances, holders may convert their Series 2024A Convertible Senior Notes and their Series 2023A Convertible Senior Notes at their option prior to the close of business on the business day preceding March 15, 2027 and September 15, 2025, respectively:

- during any calendar quarter (and only during such calendar quarter), if the last reported sale price of Southern Company's common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the applicable conversion price of the Series 2024A Convertible Senior Notes or the Series 2023A Convertible Senior Notes, as the case may be, on each applicable trading day as determined by Southern Company;
- during the five business day period after any 10 consecutive trading day period (Measurement Period) in which the applicable trading price per $1,000 principal amount of Series 2024A Convertible Senior Notes or Series 2023A Convertible Senior Notes, as the case may be, for each trading day of the Measurement Period was less than 98% of the product of the last reported sale price of the common stock and the applicable conversion rate on each such trading day; or
- upon the occurrence of certain corporate events specified in the respective supplemental indentures governing the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes.

On or after March 15, 2027, for the Series 2024A Convertible Senior Notes, and September 15, 2025, for the Series 2023A Convertible Senior Notes, a holder may convert all or any portion of its Series 2024A Convertible Senior Notes or its Series 2023A Convertible Senior Notes, as the case may be. at any time prior to the close of business on the second scheduled trading day immediately preceding the applicable maturity date regardless of the foregoing conditions.

Southern Company will settle conversions of the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes by paying cash up to the aggregate principal amount of the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes to be converted and paying or delivering, as the case may be, cash, shares of common stock, or a combination of cash and shares of common stock, at Southern Company's election, in respect of the remainder, if any, of Southern Company's conversion obligation in excess of the aggregate principal amount of the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes being converted. The Series 2024A Convertible Senior Notes are initially convertible

at a rate of 10.8166 shares of common stock per $1,000 principal amount converted, which is approximately equal to $92.45 per share of common stock. The Series 2023A Convertible Senior Notes are initially convertible at a rate of 11.8818 shares of common stock per $1,000 principal amount converted, which is approximately equal to $84.16 per share of common stock. These conversion rates will be subject to adjustment upon the occurrence of certain specified events but will not be adjusted for accrued and unpaid interest. In addition, upon the occurrence of a make-whole fundamental change (as defined in the respective supplemental indentures governing the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes), Southern Company will, in certain circumstances, increase the applicable conversion rate by a number of additional shares of common stock for conversions in connection with the make-whole fundamental change.

Upon the occurrence of a fundamental change (as defined in the respective supplemental indentures governing the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes), holders of the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes may require Southern Company to purchase all or a portion of their Series 2024A Convertible Senior Notes and their Series 2023A Convertible Senior Notes, in principal amounts equal to $1,000 or an integral multiple thereof, for cash at a price equal to 100% of the principal amount of the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes to be purchased plus any accrued and unpaid interest.

Equity Distribution Agreement

In May 2024, Southern Company established an at-the-market program by entering into an equity distribution agreement pursuant to which it may sell, from time to time, up to an aggregate of 50 million shares of its common stock, including through forward sale contracts. In November 2024, Southern Company entered into separate forward sale contracts with forward purchasers for the sale of:

- 1,000,000 shares of common stock with an initial forward price of $86.5645 per share and
- 1,000,000 shares of common stock with an initial forward price of $87.9658 per share.

In addition, in December 2024, Southern Company entered into a forward sale contract with a forward purchaser for the sale of 436,614 shares of its common stock, 143,920 of which had been sold by the forward seller as of December 31, 2024, with the remaining 292,694 shares sold subsequent to December 31, 2024, all with an initial forward price of $83.3293 per share.

Each initial forward price is subject to adjustment under certain specified circumstances as specified in the forward sale contracts. Southern Company may settle each of the forward transactions in shares, cash, or net shares on or before December 31, 2025. As of December 31, 2024, no shares had been settled under these forward confirmations.

Bank Credit Arrangements

At December 31, 2024, committed credit arrangements with banks were as follows:

Company	Expires				Total	Unused	Expires within One Year
	2025	2026	2027	2029			
				(in millions)			
Southern Company parent[(a)]	$ 150	$ —	$ —	$ 1,850	$ 2,000	$ 1,998	$ 150
Alabama Power[(b)]	—	665	—	700	1,365	1,364	—
Georgia Power	300	—	—	1,750	2,050	2,026	300
Mississippi Power	—	—	275	—	275	275	—
Southern Power[(a)(c)]	—	—	—	600	600	600	—
Southern Company Gas[(d)]	100	—	—	1,500	1,600	1,598	100
SEGCO	30	—	—	—	30	30	30
Southern Company	$ 580	$ 665	$ 275	$ 6,400	$ 7,920	$ 7,891	$ 580

(a) Arrangement expiring in 2029 represents a $2.45 billion combined arrangement for Southern Company and Southern Power allowing for flexible sublimits.

(b) Includes $15 million expiring in 2026 at Alabama Property Company, a wholly-owned subsidiary of Alabama Power, of which $14 million was unused at December 31, 2024. Alabama Power is not party to this arrangement.

(c) Does not include Southern Power Company's $75 million and $100 million continuing letter of credit facilities for standby letters of credit, expiring in 2027 and 2026, respectively, of which $16 million and $11 million, respectively, was unused at December 31, 2024. Southern Power's subsidiaries are not parties to its bank credit arrangements or letter of credit facilities.

(d) Southern Company Gas, as the parent entity, guarantees the obligations of Southern Company Gas Capital, which is the borrower of $800 million of the credit arrangement expiring in 2029. Southern Company Gas' committed credit arrangement expiring in 2029 also includes $700 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas. Pursuant to the multi-year credit arrangement expiring in 2029, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. Nicor Gas is also the borrower under a $100 million credit arrangement expiring in 2025. See "Structural Considerations" herein for additional information.

The bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Registrants and Nicor Gas. Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

These bank credit arrangements, as well as the term loan arrangements of the Registrants, Nicor Gas, and SEGCO, contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) that are restricted only to the indebtedness of the individual company. The cross-acceleration provisions to other indebtedness would trigger an event of default if the applicable borrower defaulted on indebtedness, the payment of which was then accelerated. Southern Company's, Mississippi Power's, Southern Company Gas', and Nicor Gas' credit arrangements contain covenants that limit debt levels to 70% of total capitalization, as defined in the agreements, and the other subsidiaries' bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes junior subordinated notes and, in certain arrangements, other hybrid securities. Additionally, for Southern Company and Southern Power, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power to the extent such debt is non-recourse to Southern Power and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2024, the Registrants, Nicor Gas, and SEGCO were in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

A portion of the unused credit with banks is allocated to provide liquidity support to certain revenue bonds of the traditional electric operating companies and the commercial paper programs of the Registrants, Nicor Gas, and SEGCO. At December 31, 2024, outstanding variable rate demand revenue bonds of the traditional electric operating companies with allocated liquidity support totaled approximately $1.7 billion (comprised of approximately $796 million at Alabama Power, $819 million at Georgia Power, and $69 million at Mississippi Power). In addition, at December 31, 2024, Alabama Power and Georgia Power had approximately $207 million and $157 million, respectively, of fixed rate revenue bonds outstanding that are required to be remarketed within the next 12 months. Alabama Power's $207 million of fixed rate revenue bonds are classified as securities due within one year on its balance sheets as they are not covered by long-term committed credit. All other variable rate demand revenue bonds and fixed rate revenue bonds required to be remarketed within the next 12 months are classified as long-term debt on the balance sheets as a result of available long-term committed credit.

At both December 31, 2024 and 2023, Southern Power had $106 million of cash collateral posted related to PPA requirements, which is included in other deferred charges and assets on Southern Power's consolidated balance sheets.

Notes Payable

The Registrants, Nicor Gas, and SEGCO make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above under "Bank Credit Arrangements." Southern Power's subsidiaries are not parties or obligors to its commercial paper program. Southern Company Gas maintains commercial paper programs at Southern Company Gas Capital and at Nicor Gas. Nicor Gas' commercial paper program supports working capital needs at Nicor Gas as Nicor Gas is not permitted to make money pool loans to affiliates. All of Southern Company Gas'

other subsidiaries benefit from Southern Company Gas Capital's commercial paper program. See "Structural Considerations" herein for additional information.

In addition, Southern Company and certain of its subsidiaries have entered into various bank term loan agreements. Unless otherwise stated, the proceeds of these loans were used to repay existing indebtedness and for general corporate purposes, including working capital and, for the subsidiaries, their continuous construction programs.

Commercial paper and short-term bank term loans are included in notes payable in the balance sheets. Details of short-term borrowings for the applicable Registrants were as follows:

	Notes Payable at December 31, 2024		Notes Payable at December 31, 2023	
	Amount Outstanding	Weighted Average Interest Rate	Amount Outstanding	Weighted Average Interest Rate
	(in millions)		*(in millions)*	
Southern Company				
Commercial paper	**$ 1,138**	**4.7 %**	$ 1,794	5.6 %
Short-term bank debt	**200**	**5.3**	520	6.4
Total	**$ 1,338**	**4.8 %**	$ 2,314	5.7 %
Alabama Power				
Commercial paper	**$ —**	**— %**	$ 40	5.5 %
Georgia Power				
Commercial paper	**$ —**	**— %**	$ 809	5.6 %
Short-term bank debt	**200**	**5.3**	520	6.4
Total	**$ 200**	**5.3 %**	$ 1,329	5.9 %
Mississippi Power				
Commercial paper	**$ 14**	**4.6 %**	$ —	— %
Southern Power				
Commercial paper	**$ —**	**— %**	$ 138	5.5 %
Southern Company Gas				
Commercial paper:				
Southern Company Gas Capital	**$ 283**	**4.7 %**	$ 23	5.5 %
Nicor Gas	**172**	**4.6**	392	5.5
Total	**$ 455**	**4.7 %**	$ 415	5.5 %

See "Bank Credit Arrangements" herein for information on bank term loan covenants that limit debt levels and cross-acceleration or cross-default provisions.

Outstanding Classes of Capital Stock

Southern Company

Common Stock

Stock Issued

During 2024, Southern Company issued approximately 5.8 million shares of common stock primarily through equity compensation plans.

Shares Reserved

At December 31, 2024, a total of 177 million shares were reserved for issuance pursuant to the Southern Investment Plan, employee savings plans, the Equity and Incentive Compensation Plan (which includes performance share units and restricted stock units as discussed in Note 12), an at-the-market program, and the Series 2024A Convertible Senior Notes and Series 2023A Convertible Senior Notes (as discussed under "Convertible Senior Notes" herein). Of the shares reserved, 25 million shares are available for awards under the Equity and Incentive Compensation Plan at December 31, 2024.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share (EPS) is attributable to awards outstanding under stock-based compensation plans, the Series 2024A Convertible Senior Notes, the Series 2023A Convertible Senior Notes, and forward sale contracts pursuant to the equity distribution agreement. EPS dilution resulting from stock-based compensation plans and the forward sale contracts is determined using the treasury stock method, and EPS dilution resulting from the Series 2024A Convertible Senior Notes and the Series 2023A Convertible Senior Notes is determined using the net share settlement method. See Note 12 and "Convertible Senior Notes" and "Equity Distribution Agreement" herein for additional information. Shares used to compute diluted EPS were as follows:

	Average Common Stock Shares		
	2024	2023	2022
		(in millions)	
As reported shares	**1,096**	1,092	1,075
Effect of stock-based compensation	**6**	6	6
Diluted shares	**1,102**	1,098	1,081

For all periods presented, an immaterial number of stock-based compensation awards was excluded from the diluted EPS calculation because the awards were anti-dilutive.

For 2024, there was no dilution resulting from the Series 2024A Convertible Senior Notes and the forward sale contracts, and the dilution resulting from the Series 2023A Convertible Senior Notes was immaterial.

Preferred Stock of Subsidiaries

As discussed further under "Alabama Power" herein, during 2022, Alabama Power redeemed all of its preferred stock and Class A preferred stock.

Alabama Power

Alabama Power has preferred stock, Class A preferred stock, preference stock, and common stock authorized, but only common stock outstanding at December 31, 2024.

During 2022, Alabama Power redeemed all of its preferred stock and Class A preferred stock at the redemption prices per share provided in the table below, plus accrued and unpaid dividends to the redemption date.

Preferred Stock Redeemed During 2022	Par Value/Stated Capital Per Share	Shares	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	$103.23
4.72% Preferred Stock	$100	50,000	$102.18
4.64% Preferred Stock	$100	60,000	$103.14
4.60% Preferred Stock	$100	100,000	$104.20
4.52% Preferred Stock	$100	50,000	$102.93
4.20% Preferred Stock	$100	135,115	$105.00
5.00% Class A Preferred Stock	$25	10,000,000	$25.00

Georgia Power

Georgia Power has preferred stock, Class A preferred stock, preference stock, and common stock authorized, but only common stock outstanding.

Mississippi Power

Mississippi Power has preferred stock and common stock authorized, but only common stock outstanding.

Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2024, consolidated retained earnings included $6.5 billion of undistributed retained earnings of the subsidiaries.

The traditional electric operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

See Note 7 under "Southern Power" for information regarding the distribution requirements for certain Southern Power subsidiaries.

By regulation, Nicor Gas is restricted, up to its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. At December 31, 2024, the amount of Southern Company Gas' subsidiary retained earnings available for dividend payment totaled $1.6 billion.

Structural Considerations

Since Southern Company and Southern Company Gas are holding companies, the right of Southern Company and Southern Company Gas and, hence, the right of creditors of Southern Company or Southern Company Gas to participate in any distribution of the assets of any respective subsidiary of Southern Company or Southern Company Gas, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred stockholders of such subsidiary.

Southern Company Gas Capital was established to provide for certain of Southern Company Gas' ongoing financing needs through a commercial paper program, the issuance of various debt, hybrid securities, and other financing arrangements. Southern Company Gas fully and unconditionally guarantees all debt issued by Southern Company Gas Capital. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize Southern Company Gas Capital for its financing needs.

Southern Power Company's senior notes, bank term loan, commercial paper, and bank credit arrangement are unsecured senior indebtedness, which rank equally with all other unsecured and unsubordinated debt of Southern Power Company. Southern Power's subsidiaries are not issuers, borrowers, or obligors, as applicable, under any of these unsecured senior debt arrangements, which are effectively subordinated to any future secured debt of Southern Power Company and any potential claims of creditors of Southern Power's subsidiaries.

9. LEASES

Lessee

The Registrants recognize leases with a term of greater than 12 months on the balance sheet as lease obligations, representing the discounted future fixed payments due, along with ROU assets that will be amortized over the term of each lease.

As lessee, the Registrants lease certain electric generating units (including renewable energy facilities), real estate/land, communication towers, railcars, and other equipment and vehicles. The major categories of lease obligations are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
At December 31, 2024						
Electric generating units(*)	**$ 672**	**$ 56**	**$ 1,509**	**$ —**	**$ —**	**$ —**
Real estate/land	**834**	**3**	**45**	**2**	**540**	**20**
Communication towers	**118**	**2**	**4**	**—**	**—**	**21**
Railcars	**64**	**31**	**29**	**4**	**—**	**—**
Other	**52**	**2**	**2**	**16**	**—**	**—**
Total	**$ 1,740**	**$ 94**	**$ 1,589**	**$ 22**	**$ 540**	**$ 41**
At December 31, 2023						
Electric generating units(*)	$ 670	$ 58	$ 1,028	$ —	$ —	$ —
Real estate/land	871	4	54	2	546	28
Communication towers	123	1	4	—	—	23
Railcars	64	32	27	5	—	—
Other	60	3	2	18	—	—
Total	$ 1,788	$ 98	$ 1,115	$ 25	$ 546	$ 51

* Amounts related to affiliate leases are eliminated in consolidation for Southern Company. See "Contracts that Contain a Lease" herein for additional information.

Real estate/land leases primarily consist of commercial real estate leases at Southern Company, Georgia Power, and Southern Company Gas and various land leases primarily associated with renewable energy facilities at Southern Power. The commercial real estate leases have remaining terms of up to 20 years while the land leases have remaining terms of up to 44 years, including renewal periods.

Communication towers are leased for the installation of equipment to provide cellular phone service to customers and to support the automated meter infrastructure programs at the traditional electric operating companies and Nicor Gas. Communication tower leases have remaining terms of up to 16 years.

Renewal options exist in many of the leases. The expected term used in calculating the lease obligation generally reflects only the noncancelable period of the lease unless it is considered reasonably certain that the lease will be extended. Land leases associated with renewable energy facilities at Southern Power and communication tower leases for automated meter infrastructure at Nicor Gas include renewal periods reasonably certain of exercise resulting in an expected lease term at least equal to the expected life of the renewable energy facilities and the automated meter infrastructure, respectively.

Contracts that Contain a Lease

While not specifically structured as a lease, some of the PPAs at Alabama Power and Georgia Power are deemed to represent a lease of the underlying electric generating units when the terms of the PPA convey the right to control the use of the underlying assets. Amounts recorded for leases of electric generating units are generally based on the amount of scheduled capacity payments due over the remaining term of the PPA, which varies between three and 15 years. Georgia Power has several PPAs with Southern Power that Georgia Power accounts for as leases with a lease obligation of $893 million and $416 million at December 31, 2024

and 2023, respectively. The amount paid for energy under these affiliate PPAs reflects a price that would be paid in an arm's-length transaction as reviewed and approved by both the Georgia PSC and the FERC. Amounts related to the affiliate PPAs are eliminated in consolidation for Southern Company.

Short-term Leases

Leases with an initial term of 12 months or less are not recorded on the balance sheet; the Registrants generally recognize lease expense for these leases on a straight-line basis over the lease term.

Residual Value Guarantees

Residual value guarantees exist primarily in railcar leases at Alabama Power and Georgia Power, with Georgia Power's railcar leases terminating in June 2024. The amounts probable of being paid under those guarantees are included in the lease payments. All such amounts were immaterial at December 31, 2024 and 2023.

Lease and Nonlease Components

For all asset categories, with the exception of electric generating units, gas pipelines, and real estate leases, the Registrants combine lease payments and any nonlease components, such as asset maintenance, for purposes of calculating the lease obligation and the ROU asset.

Balance sheet amounts recorded for operating and finance leases are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
At December 31, 2024						
Operating Leases						
Operating lease ROU assets, net	**$ 1,386**	**$ 84**	**$ 1,331**	**$ 8**	**$ 484**	**$ 38**
Operating lease obligations - current	**$ 200**	**$ 14**	**$ 169**	**$ 4**	**$ 29**	**$ 11**
Operating lease obligations - non-current	**1,253**	**76**	**1,159**	**4**	**511**	**30**
Total operating lease obligations(*)	**$ 1,453**	**$ 90**	**$ 1,328**	**$ 8**	**$ 540**	**$ 41**
Finance Leases						
Finance lease ROU assets, net	**$ 254**	**$ 4**	**$ 227**	**$ 14**	**$ —**	**$ —**
Finance lease obligations - current	**$ 9**	**$ 1**	**$ 20**	**$ 1**	**$ —**	**$ —**
Finance lease obligations - non-current	**278**	**3**	**241**	**13**	**—**	**—**
Total finance lease obligations	**$ 287**	**$ 4**	**$ 261**	**$ 14**	**$ —**	**$ —**
At December 31, 2023						
Operating Leases						
Operating lease ROU assets, net	$ 1,432	$ 87	$ 884	$ 9	$ 488	$ 47
Operating lease obligations - current	$ 183	$ 12	$ 135	$ 3	$ 29	$ 11
Operating lease obligations - non-current	1,307	81	740	6	517	40
Total operating lease obligations(*)	$ 1,490	$ 93	$ 875	$ 9	$ 546	$ 51
Finance Leases						
Finance lease ROU assets, net	$ 272	$ 5	$ 203	$ 15	$ —	$ —
Finance lease obligations - current	$ 11	$ 2	$ 18	$ 1	$ —	$ —
Finance lease obligations - non-current	287	3	222	15	—	—
Total finance lease obligations	$ 298	$ 5	$ 240	$ 16	$ —	$ —

(*) Includes operating lease obligations related to PPAs at Southern Company, Alabama Power, and Georgia Power totaling $567 million, $55 million, and $1.3 billion, respectively, at December 31, 2024 and $566 million, $58 million, and $813 million, respectively, at December 31, 2023.

If not presented separately on the Registrants' balance sheets, amounts related to leases are presented as follows: operating lease ROU assets, net are included in "other deferred charges and assets"; operating lease obligations are included in "other current liabilities" and "other deferred credits and liabilities," as applicable; finance lease ROU assets, net are included in "plant in service"; and finance lease obligations are included in "securities due within one year" and "long-term debt," as applicable.

Lease costs for 2024, 2023, and 2022, which includes both amounts recognized as operations and maintenance expense and amounts capitalized as part of the cost of another asset, are as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024						
Lease cost						
Operating lease cost(*)	**$ 248**	**$ 19**	**$ 190**	**$ 4**	**$ 27**	**$ 12**
Finance lease cost:						
Amortization of ROU assets	**20**	**2**	**23**	**1**	**—**	**—**
Interest on lease obligations	**15**	**—**	**15**	**1**	**—**	**—**
Total finance lease cost	**35**	**2**	**38**	**2**	**—**	**—**
Short-term lease costs	**37**	**15**	**15**	**—**	**—**	**—**
Variable lease cost	**48**	**(1)**	**77**	**—**	**4**	**—**
Total lease cost	**$ 368**	**$ 35**	**$ 320**	**$ 6**	**$ 31**	**$ 12**
2023						
Lease cost						
Operating lease cost(*)	$ 252	$ 16	$ 192	$ 5	$ 34	$ 12
Finance lease cost:						
Amortization of ROU assets	24	2	19	1	—	—
Interest on lease obligations	14	—	17	—	—	—
Total finance lease cost	38	2	36	1	—	—
Short-term lease costs	40	16	16	—	—	—
Variable lease cost	47	—	74	—	4	—
Total lease cost	$ 377	$ 34	$ 318	$ 6	$ 38	$ 12
2022						
Lease cost						
Operating lease cost(*)	$ 297	$ 59	$ 198	$ 5	$ 32	$ 15
Finance lease cost:						
Amortization of ROU assets	23	1	15	1	—	—
Interest on lease obligations	13	—	17	1	—	—
Total finance lease cost	36	1	32	2	—	—
Short-term lease costs	64	44	13	—	—	—
Variable lease cost	125	13	105	—	5	—
Sublease income	(1)	—	—	—	—	—
Total lease cost	$ 521	$ 117	$ 348	$ 7	$ 37	$ 15

(*) Includes operating lease costs related to PPAs at Southern Company, Alabama Power, and Georgia Power totaling $108 million, $5 million, and $168 million, respectively, in 2024, $112 million, $4 million, and $174 million, respectively, in 2023, and $162 million, $48 million, and $180 million, respectively, in 2022.

Georgia Power has variable lease payments that are based on the amount of energy produced by certain renewable generating facilities subject to PPAs, including $45 million, $42 million, and $45 million in 2024, 2023, and 2022, respectively, from finance leases which are included in purchased power on Georgia Power's statements of income, of which $22 million, $21 million, and $21 million was included in purchased power, affiliates in 2024, 2023, and 2022, respectively.

Other information with respect to cash and noncash activities related to leases, as well as weighted-average lease terms and discount rates, is as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024						
Other information						
Cash paid for amounts included in the measurements of lease obligations:						
Operating cash flows from operating leases	**$ 243**	**$ 19**	**$ 186**	**$ 4**	**$ 33**	**$ 12**
Operating cash flows from finance leases	**15**	**—**	**21**	**—**	**—**	**—**
Financing cash flows from finance leases	**11**	**2**	**23**	**1**	**—**	**—**
ROU assets obtained under operating leases	**146**	**11**	**609**	**—**	**10**	**1**
Reassessment of ROU assets under operating leases	**(7)**	**—**	**—**	**—**	**(7)**	**—**
ROU assets obtained under finance leases	**1**	**—**	**44**	**—**	**—**	**—**
2023						
Other information						
Cash paid for amounts included in the measurements of lease obligations:						
Operating cash flows from operating leases	$ 253	$ 17	$ 199	$ 5	$ 33	$ 12
Operating cash flows from finance leases	15	—	22	—	—	—
Financing cash flows from finance leases	18	2	16	1	—	—
ROU assets obtained under operating leases	100	30	26	1	7	7
ROU assets obtained under finance leases	3	3	18	—	—	—
2022						
Other information						
Cash paid for amounts included in the measurements of lease obligations:						
Operating cash flows from operating leases	$ 303	$ 58	$ 206	$ 5	$ 30	$ 14
Operating cash flows from finance leases	11	—	20	1	—	—
Financing cash flows from finance leases	16	1	10	1	—	—
ROU assets obtained under operating leases	56	10	17	9	—	3
Reassessment of ROU assets under operating leases	16	—	—	—	16	—
ROU assets obtained under finance leases	118	2	116	—	—	—

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
At December 31, 2024						
Weighted-average remaining lease term in years:						
Operating leases	**16.4**	**10.2**	**7.9**	**4.3**	**32.3**	**6.8**
Finance leases	**16.0**	**2.7**	**10.1**	**10.9**	**N/A**	**N/A**
Weighted-average discount rate:						
Operating leases	**4.73 %**	**5.04 %**	**4.73 %**	**3.83 %**	**4.88 %**	**3.84 %**
Finance leases	**4.86 %**	**4.05 %**	**5.8 %**	**2.74 %**	**N/A**	**N/A**
At December 31, 2023						
Weighted-average remaining lease term in years:						
Operating leases	17.2	11.1	7.5	4.6	33.1	7.0
Finance leases	16.7	4.3	10.6	11.9	N/A	N/A
Weighted-average discount rate:						
Operating leases	4.68 %	5.02 %	4.58 %	3.67 %	4.89 %	3.80 %
Finance leases	4.85 %	3.93 %	5.95 %	2.74 %	N/A	N/A

Maturities of lease liabilities are as follows:

	At December 31, 2024					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Maturity Analysis						
Operating leases:						
2025	$ 239	$ 18	$ 228	$ 4	$ 31	$ 12
2026	212	15	224	3	29	9
2027	190	12	223	1	29	4
2028	170	9	217	—	29	3
2029	138	7	196	—	30	4
Thereafter	1,255	56	511	1	978	15
Total	2,204	117	1,599	9	1,126	47
Less: Present value discount	751	27	271	1	586	6
Operating lease obligations	$ 1,453	$ 90	$ 1,328	$ 8	$ 540	$ 41
Finance leases:						
2025	$ 28	$ 2	$ 39	$ 2	$ —	$ —
2026	27	1	41	2	—	—
2027	26	1	41	1	—	—
2028	25	—	42	1	—	—
2029	25	—	42	1	—	—
Thereafter	290	—	139	9	—	—
Total	421	4	344	16	—	—
Less: Present value discount	134	—	83	2	—	—
Finance lease obligations	$ 287	$ 4	$ 261	$ 14	$ —	$ —

Payments made under PPAs at Georgia Power for energy generated from certain renewable energy facilities accounted for as operating and finance leases are considered variable lease costs and are therefore not reflected in the above maturity analysis.

At December 31, 2024, Georgia Power has two affiliate PPAs with Southern Power that have not yet commenced and will be accounted for as leases. The PPAs each have a term of 10 years and are expected to commence in 2025 and 2028. The estimated total obligations associated with these PPAs is $83 million. Southern Company Gas has executed an 11.5-year building lease agreement that will commence during the first half of 2025. The lease has a total obligation of approximately $105 million.

Lessor

The Registrants are each considered lessors in various arrangements that have been determined to contain a lease due to the customer's ability to control the use of the underlying asset owned by the applicable Registrant. For the traditional electric operating companies, these arrangements consist of outdoor lighting contracts accounted for as operating leases with initial terms of up to 10 years, after which the contracts renew on a month-to-month basis at the customer's option. For Georgia Power, these arrangements also include PPAs related to electric generating units accounted for as operating leases with remaining terms of up to 15 years. For Mississippi Power, these arrangements also include a tolling arrangement related to an electric generating unit accounted for as a sales-type lease with a remaining term of 14 years. For Southern Power, these arrangements consist of PPAs related to electric generating units accounted for as operating leases with remaining terms of up to 22 years and PPAs related to battery energy storage facilities accounted for as sales-type leases with remaining terms of up to 17 years. Southern Company Gas is the lessor in operating leases related to gas pipelines with remaining terms of up to 18 years. For Southern Company, these arrangements also include PPAs related to fuel cells accounted for as operating leases with remaining terms of up to 9 years.

Lease income for 2024, 2023, and 2022, is as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024						
Lease income - interest income on sales-type leases	**$ 24**	**$ —**	**$ —**	**$ 15**	**$ 9**	**$ —**
Lease income - operating leases	**136**	**9**	**28**	**3**	**88**	**36**
Variable lease income	**417**	**1**	**—**	**—**	**450**	**—**
Total lease income	**$ 577**	**$ 10**	**$ 28**	**$ 18**	**$ 547**	**$ 36**
2023						
Lease income - interest income on sales-type leases	$ 24	$ —	$ —	$ 14	$ 10	$ —
Lease income - operating leases	164	35	29	2	85	37
Variable lease income	406	1	—	—	437	—
Total lease income	$ 594	$ 36	$ 29	$ 16	$ 532	$ 37
2022						
Lease income - interest income on sales-type leases	$ 25	$ —	$ —	$ 15	$ 10	$ —
Lease income - operating leases	208	77	32	2	85	36
Variable lease income	417	1	—	—	448	—
Total lease income	$ 650	$ 78	$ 32	$ 17	$ 543	$ 36

Lease payments received under tolling arrangements and PPAs consist of either scheduled payments or variable payments based on the amount of energy produced by the underlying electric generating units. Lease income related to PPAs is included in wholesale revenues for Alabama Power, Georgia Power, and Southern Power. Scheduled payments to be received under outdoor lighting contracts' initial terms, tolling arrangements, and PPAs accounted for as leases are presented in the following maturity analyses.

The undiscounted cash flows expected to be received for in-service leased assets under the leases are as follows:

	At December 31, 2024		
	Southern Company	Mississippi Power	Southern Power
	(in millions)		
2025	$ 52	$ 24	$ 15
2026	38	23	15
2027	37	22	15
2028	36	21	15
2029	35	20	15
Thereafter	302	132	170
Total undiscounted cash flows	$ 500	$ 242	$ 245
Net investment in sales-type lease(*)	297	139	158
Difference between undiscounted cash flows and discounted cash flows	$ 203	$ 103	$ 87

(*) For Mississippi Power, included in other current assets ($10 million and $10 million at December 31, 2024 and 2023, respectively) and other property and investments ($129 million and $138 million at December 31, 2024 and 2023, respectively) on the balance sheets. For Southern Power, included in other current assets ($15 million and $15 million at December 31, 2024 and 2023, respectively) and net investment in sales-type leases ($143 million and $148 million at December 31, 2024 and 2023, respectively) on the balance sheets.

The undiscounted cash flows to be received under operating leases and contracts accounted for as operating leases are as follows:

	At December 31, 2024			
	Southern Company	Alabama Power	Southern Power	Southern Company Gas
	(in millions)			
2025	$ 117	$ 6	$ 142	$ 35
2026	111	5	148	29
2027	109	4	150	28
2028	109	4	161	28
2029	112	3	164	28
Thereafter	621	31	506	326
Total	$ 1,179	$ 53	$ 1,271	$ 474

Southern Power receives payments for renewable energy under PPAs accounted for as operating leases that are considered contingent rents and are therefore not reflected in the table above. Alabama Power and Southern Power allocate revenue to the nonlease components of PPAs based on the stand-alone selling price of capacity and energy. The undiscounted cash flows to be received under contracts accounted for as operating leases at Georgia Power and Mississippi Power are immaterial.

Southern Company Leveraged Lease

At December 31, 2024, a subsidiary of Southern Holdings had one leveraged lease agreement, which relates to energy generation, with an expected remaining term of seven years. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt, related to this investment. Southern Company wrote off the related investment balance in 2020 following an evaluation of the recoverability of the lease receivable and the expected residual value of the generation assets at the end of the lease.

In June 2022, the Southern Holdings subsidiary operating the generating plant for the lessee provided notice to the lessee to terminate the related operating and maintenance agreement effective June 30, 2023. Subsequently, the lessee failed to make the semi-annual lease payment due in December 2022. As a result, the Southern Holdings subsidiary was unable to make its corresponding payment to the holders of the underlying non-recourse debt related to the generation assets. The parties to the lease entered into forbearance agreements which suspended the related contractual rights of the parties while they continued

restructuring negotiations, during which the termination date for the operating and maintenance agreement was delayed until July 31, 2023. The negotiations were completed in July 2023, resulting in the Southern Holdings subsidiary agreeing to continue operating the plant for the lessee until the lessee's associated power off-take agreement ends in 2032, subject to certain terms and conditions. The restructuring had no material impact on Southern Company's financial statements. Southern Company will continue to monitor the operational performance of the underlying assets and evaluate the ability of the lessee to continue to meet its obligations, including those associated with a future closure or retirement of the generation assets and associated properties, including the dry ash landfill.

10. INCOME TAXES

Southern Company files a consolidated federal income tax return and the Registrants file various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis, and each subsidiary is allocated an amount of tax similar to that which would be paid if it filed a separate income tax return except for certain credit utilization and state apportionment results. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2024					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Federal —						
Current	$ 221	$ 357	$ 200	$ 32	$ (112)	$ 84
Deferred	387	(111)	211	2	106	86
Total federal	608	246	411	34	(6)	170
State —						
Current	152	103	52	(1)	6	42
Deferred	209	11	140	14	(13)	46
Total state	361	114	192	13	(7)	88
Total	$ 969	$ 360	$ 603	$ 47	$ (13)	$ 258

	2023					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Federal —						
Current	$ 54	$ 242	$ 205	$ 49	$ (320)	$ 62
Deferred	299	(257)	195	(26)	334	68
Total federal	353	(15)	400	23	14	130
State —						
Current	41	82	37	1	(1)	24
Deferred	102	14	11	12	(1)	57
Total state	143	96	48	13	(2)	81
Total	$ 496	$ 81	$ 448	$ 36	$ 12	$ 211

	2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Federal —						
Current	$ 10	$ 54	$ 38	$ 42	$ (43)	$ 122
Deferred	455	259	152	(16)	56	(3)
Total federal	465	313	190	26	13	119
State —						
Current	27	14	(21)	—	2	42
Deferred	303	96	201	11	5	19
Total state	330	110	180	11	7	61
Total	$ 795	$ 423	$ 370	$ 37	$ 20	$ 180

Southern Company's and Southern Power's ITCs and PTCs generated in the current tax year and carried forward from prior tax years that cannot be utilized or transferred in the current tax year are reclassified from current to deferred taxes in federal income tax expense in the tables above. Southern Power's ITCs and PTCs reclassified in this manner were immaterial in 2024 and 2023 and $17 million in 2022. Southern Power received $71 million, $332 million, and $49 million of cash related to federal ITCs under renewable energy initiatives in 2024, 2023, and 2022, respectively. See "Deferred Tax Assets and Liabilities" herein for additional information.

In accordance with regulatory requirements, deferred federal ITCs for the traditional electric operating companies are amortized over the average life of the related property, with such amortization normally applied as a credit to reduce depreciation and amortization in the statements of income. Southern Power's and the natural gas distribution utilities' deferred federal ITCs, as well as certain state ITCs for Nicor Gas, are amortized to income tax expense over the life of the respective asset. ITCs amortized in 2024, 2023, and 2022 were immaterial for the traditional electric operating companies and Southern Company Gas and were as follows for Southern Company and Southern Power:

	Southern Company	Southern Power
	(in millions)	
2024	**$ 109**	**$ 58**
2023	84	58
2022	83	58

When Southern Power recognizes tax credits, the tax basis of the asset is reduced by 50% of the ITCs received, which, together with the deferred credit, results in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation.

State ITCs and other state credits, which are recognized in the period in which the credits are generated, reduced Georgia Power's income tax expense by $44 million in 2024, $49 million in 2023, and $53 million in 2022.

Southern Power's federal and state PTCs, which are recognized in the period in which the credits are generated, reduced Southern Power's income tax expense by $32 million in 2024, $26 million in 2023, and $27 million in 2022.

In 2024, Alabama Power, Georgia Power, and Southern Power entered into transferability agreements with non-affiliated parties to sell ITCs and PTCs at a discount to the generated credit value in 2024, 2025, and 2026. Georgia Power and Southern Power received cash of $11 million and $24 million, respectively, from credits transferred during the year. The discount will be recorded as a reduction in tax credits recognized in the financial statements. The Southern Company system continues to explore the ability to efficiently monetize its tax credits through third-party transferability agreements.

Pursuant to the Vogtle Joint Ownership Agreements, Georgia Power paid $131 million in 2024 and $39 million in 2023 to the other Vogtle Owners for advanced nuclear PTCs for Plant Vogtle Unit 3 and 4, which were utilized and not reflected as a

reduction to current income tax expense. The gains recognized in both periods were recorded in income tax benefit and were immaterial.

Effective Tax Rate

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity at the traditional electric operating companies, flowback of excess deferred income taxes at the regulated utilities, and federal income tax benefits from ITCs and PTCs primarily at Southern Power, Georgia Power, and Alabama Power.

A reconciliation of the federal statutory income tax rate to the effective income tax (benefit) rate is as follows:

	2024					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Federal statutory rate	**21.0 %**	**21.0 %**	**21.0 %**	**21.0 %**	**21.0 %**	**21.0 %**
State income tax, net of federal deduction	**3.6**	**5.0**	**1.7**	**4.4**	**(2.3)**	**7.0**
Changes in valuation allowance, net of federal benefit	**1.9**	**—**	**3.1**	**—**	**—**	**—**
Employee stock plans' dividend deduction	**(0.4)**	—	—	—	—	—
Non-deductible book depreciation	**0.6**	**0.6**	**0.7**	**0.3**	**—**	**—**
Flowback of excess deferred income taxes	**(3.9)**	**(5.3)**	**(2.2)**	**(6.5)**	—	**(2.2)**
AFUDC-Equity	**(0.8)**	**(0.7)**	**(1.0)**	**—**	**—**	**—**
Federal PTCs	**(2.8)**	**(0.1)**	**(3.7)**	**—**	**(17.2)**	**—**
ITC amortization	**(1.2)**	**(0.1)**	**(0.2)**	**—**	**(26.4)**	**—**
Noncontrolling interests	**0.6**	—	—	—	**17.1**	—
Other	**(0.1)**	**—**	**(0.2)**	**—**	**0.2**	**—**
Effective income tax (benefit) rate	**18.5 %**	**20.4 %**	**19.2 %**	**19.2 %**	**(7.6) %**	**25.8 %**

	2023					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
State income tax, net of federal deduction	2.9	5.2	2.1	4.9	(0.7)	7.8
Changes in valuation allowance, net of federal benefit	(0.3)	—	(0.6)	—	—	—
Employee stock plans' dividend deduction	(0.5)	—	—	—	—	—
Non-deductible book depreciation	0.7	0.7	0.8	0.4	—	—
Flowback of excess deferred income taxes	(9.2)	(19.8)	(2.6)	(10.2)	—	(2.6)
AFUDC-Equity	(1.1)	(1.2)	(1.2)	—	—	—
Federal PTCs	(1.2)	—	(1.4)	—	(7.4)	—
ITC amortization	(1.3)	(0.1)	(0.1)	—	(19.0)	—
Noncontrolling interests	0.6	—	—	—	11.1	—
Other	(0.2)	(0.2)	(0.3)	0.1	0.1	(0.6)
Effective income tax rate	11.4 %	5.6 %	17.7 %	16.2 %	5.1 %	25.6 %

	2022					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
State income tax, net of federal deduction	7.8	4.8	3.3	4.4	1.9	6.4
Changes in valuation allowance, net of federal benefit	(1.6)	—	3.2	—	—	—
Employee stock plans' dividend deduction	(0.5)	—	—	—	—	—
Non-deductible book depreciation	0.6	0.5	0.6	0.3	—	—
Flowback of excess deferred income taxes	(6.6)	(1.9)	(9.6)	(7.8)	—	(2.5)
AFUDC-Equity	(1.1)	(0.8)	(1.5)	—	—	—
Federal PTCs	—	—	—	—	(6.6)	—
ITC amortization	(1.3)	(0.1)	(0.1)	—	(17.2)	(0.1)
Noncontrolling interests	0.5	—	—	—	8.4	—
Other	—	0.3	—	0.3	(0.1)	(0.9)
Effective income tax rate	18.8 %	23.8 %	16.9 %	18.2 %	7.4 %	23.9 %

Deferred Tax Assets and Liabilities

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements of the Registrants and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	December 31, 2024					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred tax liabilities —						
Accelerated depreciation	$ 9,828	$ 2,583	$ 3,810	$ 344	$ 1,309	$ 1,575
Property basis differences	3,025	1,497	918	192	—	412
Employee benefit obligations	1,067	362	470	54	13	60
AROs	727	458	221	—	—	—
Under recovered fuel and natural gas costs	318	13	305	—	—	—
Regulatory assets –						
AROs	1,886	658	1,193	35	—	—
Employee benefit obligations	746	191	237	35	—	35
Remaining book value of retired assets	360	168	187	5	—	—
Storm damage reserves	216	—	216	—	—	—
Premium on reacquired debt	57	8	48	1	—	—
Other	678	171	187	61	1	201
Total deferred income tax liabilities	18,908	6,109	7,792	727	1,323	2,283
Deferred tax assets —						
AROs	2,613	1,116	1,414	35	—	—
CAMT carryforwards	40	—	18	—	—	104
ITC and PTC carryforwards	1,380	48	719	—	384	—
Employee benefit obligations	897	196	279	49	16	87
Estimated loss on plants under construction	773	—	773	—	—	—
Estimated loss on regulatory disallowance	20	—	—	—	—	20
Other state deferred tax attributes	366	—	26	224	49	16
Federal effect of net state deferred tax liabilities	402	197	100	—	23	107
Other property basis differences	176	—	75	—	85	—
State effect of federal deferred taxes	126	126	—	—	—	—
Other partnership basis differences	60	—	—	—	60	—
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	18	18	—	—	—	—
Long-term debt fair value adjustment	73	—	—	—	—	73
Other comprehensive losses	48	3	—	—	1	—
Other	601	227	160	50	20	86
Total deferred income tax assets	7,593	1,931	3,564	358	638	493
Valuation allowance	(333)	—	(157)	(41)	(27)	(6)
Net deferred income tax assets	7,260	1,931	3,407	317	611	487
Net deferred income taxes (assets)/liabilities	**$ 11,648**	**$ 4,178**	**$ 4,385**	**$ 410**	**$ 712**	**$ 1,796**
Recognized in the balance sheets:						
Accumulated deferred income taxes – assets	**$ (82)**	**$ —**	**$ —**	**$ (82)**	**$ —**	**$ —**
Accumulated deferred income taxes – liabilities	**$ 11,730**	**$ 4,178**	**$ 4,385**	**$ 492**	**$ 712**	**$ 1,796**

	December 31, 2023					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred tax liabilities —						
Accelerated depreciation	$ 9,683	$ 2,566	$ 3,628	$ 339	$ 1,346	$ 1,576
Property basis differences	2,647	1,444	812	188	—	189
Employee benefit obligations	979	321	446	49	12	74
AROs	833	476	314	—	—	—
Under recovered fuel and natural gas costs	601	80	508	13	—	—
Regulatory assets –						
AROs	1,902	667	1,196	39	—	—
Employee benefit obligations	797	213	260	37	—	11
Remaining book value of retired assets	369	143	221	5	—	—
Premium on reacquired debt	63	9	53	1	—	—
Other	700	182	223	43	2	191
Total deferred income tax liabilities	18,574	6,101	7,661	714	1,360	2,041
Deferred tax assets —						
AROs	2,735	1,143	1,510	39	—	—
ITC and PTC carryforwards	1,387	12	691	—	481	—
Employee benefit obligations	985	224	316	52	10	89
Estimated loss on plants under construction	857	—	857	—	—	—
Estimated loss on regulatory disallowance	26	—	—	—	—	26
Other state deferred tax attributes	363	—	13	231	49	8
Federal effect of net state deferred tax liabilities	418	215	92	—	27	101
Other property basis differences	197	—	83	—	97	—
State effect of federal deferred taxes	115	115	—	—	—	—
Other partnership basis differences	85	—	—	—	85	—
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	34	30	—	3	—	—
Long-term debt fair value adjustment	79	—	—	—	—	79
Other comprehensive losses	67	4	4	—	6	—
Other	538	188	152	57	18	74
Total deferred income tax assets	7,886	1,931	3,718	382	773	377
Valuation allowance	(206)	—	(75)	(41)	(27)	(7)
Net deferred income tax assets	7,680	1,931	3,643	341	746	370
Net deferred income taxes (assets)/liabilities	**$ 10,894**	**$ 4,170**	**$ 4,018**	**$ 373**	**$ 614**	**$ 1,671**
Recognized in the balance sheets:						
Accumulated deferred income taxes – assets	**$ (96)**	**$ —**	**$ —**	**$ (96)**	**$ —**	**$ —**
Accumulated deferred income taxes – liabilities	**$ 10,990**	**$ 4,170**	**$ 4,018**	**$ 469**	**$ 614**	**$ 1,671**

The traditional electric operating companies and the natural gas distribution utilities have tax-related regulatory assets (deferred income tax charges) and regulatory liabilities (deferred income tax credits). The regulatory assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest. The regulatory liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs. See Note 2 for each Registrant's related balances at December 31, 2024 and 2023.

Tax Credit Carryforwards

Federal ITC/PTC carryforwards at December 31, 2024 were as follows:

	Southern Company	Alabama Power	Georgia Power	Southern Power
		(in millions)		
Federal ITC/PTC carryforwards	$ 765	$ 48	$ 147	$ 384
Tax year in which federal ITC/PTC carryforwards begin expiring	2031	2032	2031	2035
Year by which federal ITC/PTC carryforwards are expected to be utilized	2028	2028	2028	2028

The estimated tax credit utilization reflects the various transactions described in Note 15 and could be impacted by numerous factors, including the acquisition or construction of additional renewable projects, changes in taxable income projections, transfer of eligible credits, potential income tax rate changes, and remaining final guidance on the IRA. In the third quarter 2023 and the second quarter 2024, Georgia Power started generating advanced nuclear PTCs for Plant Vogtle Units 3 and 4, respectively, beginning on each unit's respective in-service date. In addition, pursuant to the Vogtle Joint Ownership Agreements, Georgia Power is purchasing advanced nuclear PTCs for Plant Vogtle Unit 3 and 4 from the other Vogtle Owners. See Note 2 under "Georgia Power – Nuclear Construction" for additional information on Plant Vogtle Units 3 and 4.

At December 31, 2024, Southern Company and Georgia Power also had approximately $515 million and $472 million, respectively, in net state investment and other net state tax credit carryforwards for the State of Georgia that will expire between tax years 2024 and 2033 and are not expected to be fully utilized. Southern Company and Georgia Power have a net state valuation allowance of $161 million and $124 million, respectively, associated with these carryforwards, which increased during 2024 by $101 million and $64 million, respectively.

At December 31, 2024, Southern Company and certain subsidiaries also had approximately $40 million in net CAMT carryforwards that have an indefinite carryforward period and are expected to be fully utilized by 2031.

The ultimate outcome of these matters cannot be determined at this time.

Net Operating Loss Carryforwards

At December 31, 2024, the net state income tax benefit of state and local NOL carryforwards and associated valuation allowances for Southern Company's subsidiaries were as follows:

Company/Jurisdiction	Approximate Net State Income Tax Benefit of NOL Carryforwards	Tax Year NOL Begins Expiring	Net State Valuation Allowance for NOL Carryforwards
	(in millions)		*(in millions)*
Mississippi Power			
Mississippi	$ 178	2032	$ (32)
Southern Power			
Oklahoma	$ 26	2035	$ (11)
Florida	10	2034	(10)
Other states	2	2034	—
Southern Power Total	$ 38		$ (21)
Other(*)			
New York	$ 11	2036	$ (11)
New York City	14	2036	(14)
Other states	24	2025	(4)
Southern Company Total	$ 265		$ (82)

(*) Represents other non-registrant Southern Company subsidiaries. Alabama Power, Georgia Power, and Southern Company Gas did not have material state or local NOL carryforwards at December 31, 2024.

Certain state NOLs are not expected to be fully utilized prior to expiration. The ultimate outcome of these matters cannot be determined at this time.

Unrecognized Tax Benefits

Changes in unrecognized tax benefits for the periods presented were as follows:

	Southern Company	Georgia Power	Southern Company Gas
		(in millions)	
Unrecognized tax benefits at December 31, 2021	$ 47	$ —	$ —
Tax positions changes —			
Increase from prior periods	33	—	32
Unrecognized tax benefits at December 31, 2022	80	—	32
Tax positions changes —			
Increase from prior periods	88	86	2
Statute of limitations expiration	(52)	(9)	—
Unrecognized tax benefits at December 31, 2023	116	77	34
Tax positions changes —			
Increase from prior periods	**10**	**—**	**10**
Decrease from prior periods	**(44)**	**(43)**	**—**
Unrecognized tax benefits at December 31, 2024	**$ 82**	**$ 34**	**$ 44**

The unrecognized tax positions increase from prior periods for 2022 is primarily related to the amendment of certain 2018 state tax filing positions related to Southern Company Gas dispositions. If accepted by the states, these positions would decrease Southern Company's and Southern Company Gas' annual effective tax rates. The ultimate outcome of these unrecognized tax benefits is dependent on acceptance by each state and is not expected to be resolved within the next 12 months.

The unrecognized tax positions increase from prior periods for 2023 is primarily related to the amendment of certain 2019 through 2021 state tax filing positions related to tax credit utilization, a portion of which decreased in the fourth quarter 2023 due to a statute of limitations expiration. If effective settlement of the positions is favorable, these positions would decrease Southern Company's and Georgia Power's annual effective tax rates. The ultimate outcome of this unrecognized tax benefit, which is expected to be resolved within the next 12 months, is dependent on acceptance by the state or expiration of related statute of limitations.

The unrecognized tax positions reductions due to statute of limitations expiration for 2023 primarily relate to a 2019 state tax filing position to exclude certain gains from 2019 dispositions from taxation in a certain unitary state. This tax position and related interest was recognized in the fourth quarter 2023 and decreased Southern Company's annual effective tax rate.

The unrecognized tax positions increase from prior periods for 2024 is primarily related to a certain state tax filing position at Southern Company Gas. If effective settlement of this position is favorable, this position would decrease Southern Company's and Southern Company Gas' annual effective tax rates. The ultimate outcome is dependent on acceptance by the state.

The unrecognized tax positions decrease from prior periods for 2024 is primarily related to the 2019 and 2020 amended state filing positions related to tax credit utilization at Georgia Power.

All of the Registrants classify interest on tax uncertainties as interest expense. Accrued interest for all tax positions was immaterial for all years presented. None of the Registrants accrued any penalties on uncertain tax positions.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2023. Southern Company is a participant in the Compliance Assurance Process of the IRS. The IRS selected six Southern Power partnership returns for exam for the 2020 and 2021 tax years. One audit for 2021 is still under review, and the remaining audits have been closed with no change. The ultimate outcome of this matter cannot be determined at this time. The audits for the Registrants' state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2018.

11. RETIREMENT BENEFITS

The Southern Company system has a qualified defined benefit, trusteed pension plan covering substantially all employees, with the exception of PowerSecure employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2024 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2025. The Southern Company system also provides certain non-qualified defined benefits for a select group of management and highly compensated employees, which are funded on a cash basis. In addition, the Southern Company system provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric operating companies fund other postretirement trusts to the extent required by their respective regulatory commissions. Southern Company Gas has a separate unfunded supplemental retirement health care plan that provides medical care and life insurance benefits to employees of discontinued businesses. For the year ending December 31, 2025, no contributions to any other postretirement trusts are expected.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the net periodic costs for the pension and other postretirement benefit plans for the following year and the benefit obligations as of the measurement date are presented below.

Assumptions used to determine net periodic costs:	2024 Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate – benefit obligations	**5.07 %**	**5.08 %**	**5.06 %**	**5.06 %**	**5.14 %**	**5.05 %**
Discount rate – interest costs	**4.94**	**4.94**	**4.94**	**4.93**	**5.01**	**4.93**
Discount rate – service costs	**5.19**	**5.20**	**5.21**	**5.19**	**5.20**	**5.13**
Expected long-term return on plan assets	**8.30**	**8.30**	**8.30**	**8.30**	**8.30**	**8.30**
Annual salary increase	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**
Other postretirement benefit plans						
Discount rate – benefit obligations	**4.99 %**	**5.01 %**	**4.98 %**	**4.98 %**	**5.06 %**	**4.98 %**
Discount rate – interest costs	**4.90**	**4.90**	**4.89**	**4.90**	**4.94**	**4.89**
Discount rate – service costs	**5.16**	**5.17**	**5.16**	**5.16**	**5.14**	**5.16**
Expected long-term return on plan assets	**7.67**	**7.97**	**7.59**	**7.43**	**—**	**6.36**
Annual salary increase	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**

Assumptions used to determine net periodic costs:	2023 Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate – benefit obligations	5.25 %	5.26 %	5.25 %	5.25 %	5.31 %	5.24 %
Discount rate – interest costs	5.13	5.14	5.12	5.12	5.19	5.12
Discount rate – service costs	5.36	5.38	5.38	5.37	5.37	5.31
Expected long-term return on plan assets	8.40	8.40	8.40	8.40	8.40	8.40
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80
Other postretirement benefit plans						
Discount rate – benefit obligations	5.18 %	5.20 %	5.17 %	5.17 %	5.24 %	5.16 %
Discount rate – interest costs	5.08	5.09	5.07	5.08	5.12	5.07
Discount rate – service costs	5.34	5.35	5.34	5.33	5.33	5.33
Expected long-term return on plan assets	7.67	7.95	7.49	7.43	—	6.59
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80

Assumptions used to determine net periodic costs:	2022 Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate – benefit obligations	3.09 %	3.12 %	3.07 %	3.07 %	3.21 %	3.04 %
Discount rate – interest costs	2.55	2.58	2.51	2.54	2.79	2.53
Discount rate – service costs	3.34	3.36	3.37	3.35	3.36	3.21
Expected long-term return on plan assets	8.25	8.25	8.25	8.25	8.25	8.25
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80
Other postretirement benefit plans						
Discount rate – benefit obligations	2.90 %	2.95 %	2.87 %	2.88 %	3.07 %	2.82 %
Discount rate – interest costs	2.32	2.38	2.30	2.27	2.55	2.17
Discount rate – service costs	3.26	3.30	3.27	3.26	3.25	3.22
Expected long-term return on plan assets	7.21	7.54	6.88	7.22	—	6.08
Annual salary increase	4.80	4.80	4.80	4.80	4.80	4.80

Assumptions used to determine benefit obligations:	2024 Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate	**5.76 %**	**5.78 %**	**5.75 %**	**5.76 %**	**5.84 %**	**5.73 %**
Annual salary increase	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**
Other postretirement benefit plans						
Discount rate	**5.64 %**	**5.67 %**	**5.61 %**	**5.63 %**	**5.73 %**	**5.62 %**
Annual salary increase	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**	**4.60**

Assumptions used to determine benefit obligations:	2023 Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate	5.07 %	5.08 %	5.06 %	5.06 %	5.14 %	5.05 %
Annual salary increase	4.60	4.60	4.60	4.60	4.60	4.60
Other postretirement benefit plans						
Discount rate	4.99 %	5.01 %	4.98 %	4.98 %	5.06 %	4.98 %
Annual salary increase	4.60	4.60	4.60	4.60	4.60	4.60

The Registrants estimate the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of the different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio. The Registrants set the expected rate of return assumption using an arithmetic mean which represents the expected simple average return to be earned by the pension plan assets over any one year. The Registrants believe the use of the arithmetic mean is more compatible with the expected rate of return's function of estimating a single year's investment return.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO for the Registrants at December 31, 2024 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	8.00 %	4.50 %	2033
Post-65 medical	5.50	4.50	2033
Post-65 prescription	11.00	4.50	2033

Pension Plans

The total accumulated benefit obligation for the pension plans at December 31, 2024 and 2023 was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2024	**$ 11,437**	**$ 2,617**	**$ 3,438**	**$ 519**	**$ 140**	**$ 779**
December 31, 2023	11,991	2,746	3,674	546	145	808

An actuarial gain of $887 million and an actuarial loss of $493 million were recorded for the annual remeasurement of the Southern Company system pension plans at December 31, 2024 and 2023, respectively, primarily due to an increase of 69 basis points and a decrease of 18 basis points, respectively, in the overall discount rate used to calculate the benefit obligation as a result of higher market interest rates.

Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2024 and 2023 were as follows:

	2024					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	**$ 13,252**	**$ 3,076**	**$ 4,009**	**$ 599**	**$ 177**	**$ 882**
Service cost	**292**	**68**	**70**	**12**	**7**	**28**
Interest cost	**635**	**148**	**191**	**29**	**9**	**42**
Benefits paid	**(728)**	**(162)**	**(239)**	**(33)**	**(6)**	**(46)**
Actuarial gain	**(887)**	**(222)**	**(298)**	**(40)**	**(20)**	**(64)**
Balance at end of year	**12,564**	**2,908**	**3,733**	**567**	**167**	**842**
Change in plan assets						
Fair value of plan assets at beginning of year	**14,618**	**3,544**	**4,571**	**669**	**185**	**980**
Actual return on plan assets	**604**	**148**	**152**	**23**	**7**	**39**
Employer contributions	**65**	**9**	**35**	**5**	**2**	**5**
Benefits paid	**(728)**	**(162)**	**(239)**	**(33)**	**(6)**	**(46)**
Fair value of plan assets at end of year	**14,559**	**3,539**	**4,519**	**664**	**188**	**978**
Accrued asset	**$ 1,995**	**$ 631**	**$ 786**	**$ 97**	**$ 21**	**$ 136**

	2023					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	$ 12,602	$ 2,906	$ 3,851	$ 569	$ 163	$ 868
Service cost	275	64	68	11	6	24
Interest cost	626	145	191	28	8	42
Benefits paid	(744)	(155)	(224)	(32)	(6)	(104)
Actuarial loss	493	116	123	23	6	52
Balance at end of year	13,252	3,076	4,009	599	177	882
Change in plan assets						
Fair value of plan assets at beginning of year	14,218	3,427	4,456	649	178	1,002
Actual return on plan assets	1,092	260	331	50	12	79
Employer contributions	52	11	9	2	2	3
Benefits paid	(744)	(154)	(225)	(32)	(7)	(104)
Fair value of plan assets at end of year	14,618	3,544	4,571	669	185	980
Accrued asset	$ 1,366	$ 468	$ 562	$ 70	$ 8	$ 98

The projected benefit obligations for the qualified and non-qualified pension plans at December 31, 2024 are shown in the following table. All pension plan assets are related to the qualified pension plan.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Projected benefit obligations:						
Qualified pension plan	$ 11,886	$ 2,794	$ 3,622	$ 540	$ 146	$ 788
Non-qualified pension plan	678	114	111	27	21	54

Amounts recognized in the balance sheets at December 31, 2024 and 2023 related to the Registrants' pension plans consist of the following:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2024:						
Prepaid pension costs[a]	**$ 2,674**	**$ 746**	**$ 897**	**$ 124**	**$ 41**	**$ 191**
Other regulatory assets, deferred[b]	**2,708**	**741**	**973**	**144**	**—**	**126**
Other current liabilities	**(68)**	**(13)**	**(13)**	**(2)**	**(2)**	**(4)**
Employee benefit obligations[c]	**(611)**	**(102)**	**(98)**	**(25)**	**(18)**	**(51)**
Other regulatory liabilities, deferred	**(50)**	—	—	—	—	—
AOCI	**52**	**—**	**—**	**—**	**11**	**(54)**
December 31, 2023:						
Prepaid pension costs[a]	$ 2,079	$ 585	$ 706	$ 99	$ 31	$ 158
Other regulatory assets, deferred[b]	2,960	821	1,051	152	—	143
Other current liabilities	(64)	(11)	(13)	(2)	(2)	(3)
Employee benefit obligations[c]	(649)	(106)	(131)	(27)	(21)	(58)
Other regulatory liabilities, deferred	(47)	—	—	—	—	—
AOCI	79	—	—	—	20	(45)

(a) Included in prepaid pension and other postretirement benefit costs on Alabama Power's balance sheet and other deferred charges and assets on Southern Power's consolidated balance sheet.

(b) Amounts for Southern Company exclude regulatory assets of $155 million and $173 million at December 31, 2024 and 2023, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

(c) Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

Presented below are the amounts included in regulatory assets at December 31, 2024 and 2023 related to the portion of the defined benefit pension plan attributable to Southern Company, the traditional electric operating companies, and Southern Company Gas that had not yet been recognized in net periodic pension cost.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Balance at December 31, 2024					
Regulatory assets:					
Prior service cost	**$ 8**	**$ 3**	**$ 5**	**$ 1**	**$ (4)**
Net loss	**2,650**	**738**	**968**	**143**	**91**
Regulatory amortization	**—**	**—**	**—**	**—**	**39**
Total regulatory assets[*]	**$ 2,658**	**$ 741**	**$ 973**	**$ 144**	**$ 126**
Balance at December 31, 2023					
Regulatory assets:					
Prior service cost	$ 9	$ 4	$ 6	$ 1	$ (7)
Net loss	2,904	817	1,045	151	100
Regulatory amortization	—	—	—	—	50
Total regulatory assets[*]	$ 2,913	$ 821	$ 1,051	$ 152	$ 143

(*) Amounts for Southern Company exclude regulatory assets of $155 million and $173 million at December 31, 2024 and 2023, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

The changes in the balance of regulatory assets related to the portion of the defined benefit pension plan attributable to Southern Company, the traditional electric operating companies, and Southern Company Gas for the years ended December 31, 2024 and 2023 are presented in the following table:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Regulatory assets (liabilities):(*)					
Balance at December 31, 2022	$ 2,371	$ 679	$ 887	$ 123	$ 111
Net loss	576	153	178	31	34
Reclassification adjustments:					
Amortization of prior service costs	(1)	(1)	(1)	—	2
Amortization of net loss	(33)	(10)	(13)	(2)	—
Amortization of regulatory assets(*)	—	—	—	—	(4)
Total reclassification adjustments	(34)	(11)	(14)	(2)	(2)
Total change	542	142	164	29	32
Balance at December 31, 2023	$ 2,913	$ 821	$ 1,051	$ 152	$ 143
Net gain	**(199)**	**(63)**	**(58)**	**(5)**	**(7)**
Reclassification adjustments:					
Amortization of prior service costs	**(1)**	**(1)**	**(1)**	**—**	**2**
Amortization of net loss	**(55)**	**(16)**	**(19)**	**(3)**	**(1)**
Amortization of regulatory assets(*)	**—**	**—**	**—**	**—**	**(11)**
Total reclassification adjustments	**(56)**	**(17)**	**(20)**	**(3)**	**(10)**
Total change	**(255)**	**(80)**	**(78)**	**(8)**	**(17)**
Balance at December 31, 2024	**$ 2,658**	**$ 741**	**$ 973**	**$ 144**	**$ 126**

(*) Amounts for Southern Company exclude regulatory assets of $155 million and $173 million at December 31, 2024 and 2023, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

Presented below are the amounts included in AOCI at December 31, 2024 and 2023 related to the portion of the defined benefit pension plan attributable to Southern Company, Southern Power, and Southern Company Gas that had not yet been recognized in net periodic pension cost.

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
Balance at December 31, 2024			
AOCI:			
Prior service cost	**$ (1)**	**$ —**	**$ (1)**
Net (gain) loss	**53**	**11**	**(53)**
Total AOCI	**$ 52**	**$ 11**	**$ (54)**
Balance at December 31, 2023			
AOCI:			
Prior service cost	$ (1)	$ —	$ (2)
Net (gain) loss	80	20	(43)
Total AOCI	$ 79	$ 20	$ (45)

The components of OCI related to the portion of the defined benefit pension plan attributable to Southern Company, Southern Power, and Southern Company Gas for the years ended December 31, 2024 and 2023 are presented in the following table:

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
AOCI:			
Balance at December 31, 2022	$ 24	$ 11	$ (75)
Net loss	62	9	29
Reclassification adjustments:			
Amortization of prior service costs	1	—	1
Amortization of net loss	(8)	—	—
Total reclassification adjustments	(7)	—	1
Total change	55	9	30
Balance at December 31, 2023	$ 79	$ 20	$ (45)
Net gain	**(29)**	**(9)**	**(11)**
Reclassification adjustments:			
Amortization of prior service costs	**1**	**—**	**2**
Amortization of net gain	**1**	**—**	**—**
Total reclassification adjustments	**2**	**—**	**2**
Total change	**(27)**	**(9)**	**(9)**
Balance at December 31, 2024	**$ 52**	**$ 11**	**$ (54)**

Components of net periodic pension cost for the Registrants were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024						
Service cost	**$ 292**	**$ 68**	**$ 70**	**$ 12**	**$ 7**	**$ 28**
Interest cost	**635**	**148**	**191**	**29**	**9**	**42**
Expected return on plan assets	**(1,263)**	**(307)**	**(393)**	**(58)**	**(17)**	**(85)**
Recognized net loss(*)	**55**	**16**	**19**	**3**	**—**	**—**
Net amortization(*)	**—**	**1**	**1**	**—**	**—**	**15**
Prior service cost(*)	—	—	—	—	—	**(3)**
Net periodic pension income	**$ (281)**	**$ (74)**	**$ (112)**	**$ (14)**	**$ (1)**	**$ (3)**
2023						
Service cost	$ 275	$ 64	$ 68	$ 11	$ 6	$ 24
Interest cost	626	145	191	28	8	42
Expected return on plan assets	(1,229)	(297)	(385)	(56)	(15)	(85)
Recognized net (gain) loss(*)	32	9	13	2	—	(5)
Net amortization(*)	—	1	1	—	—	15
Prior service cost(*)	—	—	—	—	—	(3)
Net periodic pension income	$ (296)	$ (78)	$ (112)	$ (15)	$ (1)	$ (12)
2022						
Service cost	$ 412	$ 99	$ 103	$ 17	$ 9	$ 34
Interest cost	408	96	123	18	6	28
Expected return on plan assets	(1,265)	(306)	(399)	(57)	(15)	(91)
Recognized net loss(*)	240	62	75	11	2	8
Net amortization(*)	—	1	1	—	—	15
Prior service cost(*)	—	—	—	—	—	(3)
Net periodic pension cost (income)	$ (205)	$ (48)	$ (97)	$ (11)	$ 2	$ (9)

(*) For Southern Company, excludes amounts related to net periodic pension cost of $20 million, $17 million, and $21 million for the years ended December 31, 2024, 2023, and 2022, respectively, associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company.

The service cost component of net periodic pension cost is included in operations and maintenance expenses and all other components of net periodic pension cost are included in other income (expense), net in the Registrants' statements of income.

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Registrants have elected to amortize changes in the market value of return-seeking plan assets over five years and to recognize the changes in the market value of liability-hedging plan assets immediately. Given the significant concentration in return-seeking plan assets, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2024, estimated benefit payments were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Benefit Payments:						
2025	$ 773	$ 170	$ 245	$ 34	$ 7	$ 58
2026	801	177	250	36	8	60
2027	823	183	254	37	8	62
2028	842	187	258	38	7	64
2029	862	192	262	38	8	66
2030 to 2034	4,529	1,013	1,333	204	51	346

Other Postretirement Benefits

Changes in the APBO and the fair value of the Registrants' plan assets during the plan years ended December 31, 2024 and 2023 were as follows:

	2024					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	**$ 1,386**	**$ 329**	**$ 489**	**$ 57**	**$ 9**	**$ 172**
Service cost	**15**	**4**	**4**	**1**	**—**	**1**
Interest cost	**65**	**16**	**23**	**3**	**—**	**8**
Benefits paid	**(105)**	**(25)**	**(37)**	**(4)**	**(1)**	**(12)**
Actuarial (gain) loss	**(2)**	**2**	**9**	**(2)**	**1**	**(13)**
Balance at end of year	**1,359**	**326**	**488**	**55**	**9**	**156**
Change in plan assets						
Fair value of plan assets at beginning of year	**1,095**	**403**	**410**	**25**	**—**	**128**
Actual return on plan assets	**96**	**37**	**34**	**—**	**—**	**18**
Employer contributions	**55**	**6**	**13**	**3**	**1**	**7**
Benefits paid	**(105)**	**(25)**	**(37)**	**(4)**	**(1)**	**(12)**
Fair value of plan assets at end of year	**1,141**	**421**	**420**	**24**	**—**	**141**
Accrued asset (liability)	**$ (218)**	**$ 95**	**$ (68)**	**$ (31)**	**$ (9)**	**$ (15)**

	2023					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	$ 1,441	$ 344	$ 514	$ 59	$ 9	$ 179
Service cost	15	4	4	1	—	1
Interest cost	70	17	25	3	—	9
Benefits paid	(107)	(24)	(36)	(4)	(1)	(18)
Actuarial (gain) loss	(33)	(12)	(18)	(2)	1	1
Balance at end of year	1,386	329	489	57	9	172
Change in plan assets						
Fair value of plan assets at beginning of year	998	372	368	24	—	113
Actual return on plan assets	131	52	51	2	—	19
Employer contributions	73	3	27	3	1	14
Benefits paid	(107)	(24)	(36)	(4)	(1)	(18)
Fair value of plan assets at end of year	1,095	403	410	25	—	128
Accrued asset (liability)	$ (291)	$ 74	$ (79)	$ (32)	$ (9)	$ (44)

Amounts recognized in the balance sheets at December 31, 2024 and 2023 related to the Registrants' other postretirement benefit plans consist of the following:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2024:						
Prepaid other postretirement benefit costs[(a)]	**$ —**	**$ 95**	**$ —**	**$ —**	**$ —**	**$ —**
Other regulatory assets, deferred[(b)]	**24**	**—**	**3**	**—**	**—**	**—**
Other current liabilities	**(6)**	**—**	**—**	**—**	**(1)**	**—**
Employee benefit obligations[(c)]	**(212)**	**—**	**(68)**	**(31)**	**(8)**	**(15)**
Other regulatory liabilities, deferred	**(213)**	**(45)**	**(67)**	**(9)**	**—**	**(84)**
AOCI	**(14)**	**—**	**—**	**—**	**—**	**(15)**
December 31, 2023:						
Prepaid other postretirement benefit costs[(a)]	$ —	$ 74	$ —	$ —	$ —	$ —
Other regulatory assets, deferred[(b)]	23	—	11	—	—	—
Other current liabilities	(6)	—	—	—	(1)	—
Employee benefit obligations[(c)]	(285)	—	(79)	(32)	(8)	(44)
Other regulatory liabilities, deferred	(231)	(48)	(85)	(10)	—	(68)
AOCI	(9)	—	—	—	1	(10)

(a) Included in prepaid pension and other postretirement benefit costs on Alabama Power's balance sheet.

(b) Amounts for Southern Company exclude regulatory assets of $16 million and $24 million at December 31, 2024 and 2023, respectively, associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

(c) Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2024 and 2023 related to the other postretirement benefit plans of Southern Company, the traditional electric operating companies, and Southern Company Gas that had not yet been recognized in net periodic other postretirement benefit cost.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Balance at December 31, 2024:					
Regulatory assets (liabilities):					
Prior service cost	**$ 11**	**$ 3**	**$ 4**	**$ 1**	**$ —**
Net gain	**(200)**	**(48)**	**(68)**	**(10)**	**(71)**
Regulatory amortization	**—**	**—**	**—**	**—**	**(13)**
Total regulatory assets (liabilities)(*)	**$ (189)**	**$ (45)**	**$ (64)**	**$ (9)**	**$ (84)**
Balance at December 31, 2023:					
Regulatory assets (liabilities):					
Prior service cost	$ 13	$ 4	$ 5	$ 1	$ —
Net gain	(216)	(52)	(79)	(11)	(64)
Regulatory amortization	—	—	—	—	(4)
Total regulatory assets (liabilities)(*)	$ (203)	$ (48)	$ (74)	$ (10)	$ (68)

(*) Amounts for Southern Company exclude regulatory assets of $16 million and $24 million at December 31, 2024 and 2023, respectively, associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2024 and 2023 are presented in the following table:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Net regulatory assets (liabilities):(*)					
Balance at December 31, 2022	$ (136)	$ (21)	$ (39)	$ (9)	$ (58)
Net gain	(77)	(30)	(38)	(1)	—
Reclassification adjustments:					
Amortization of prior service costs	(1)	—	(1)	—	—
Amortization of net gain	6	3	4	—	—
Amortization of regulatory assets(*)	—	—	—	—	(10)
Total reclassification adjustments	5	3	3	—	(10)
Total change	(72)	(27)	(35)	(1)	(10)
Balance at December 31, 2023	$ (208)	$ (48)	$ (74)	$ (10)	$ (68)
Net (gain) loss	**8**	**1**	**6**	**1**	**(12)**
Reclassification adjustments:					
Amortization of prior service costs	**(2)**	**(1)**	**(1)**	**—**	**—**
Amortization of net gain	**13**	**3**	**5**	**—**	**5**
Amortization of regulatory assets(*)	**—**	**—**	**—**	**—**	**(9)**
Total reclassification adjustments	**11**	**2**	**4**	**—**	**(4)**
Total change	**19**	**3**	**10**	**1**	**(16)**
Balance at December 31, 2024	**$ (189)**	**$ (45)**	**$ (64)**	**$ (9)**	**$ (84)**

(*) Amounts for Southern Company exclude regulatory assets of $16 million and $24 million at December 31, 2024 and 2023, respectively, associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

Presented below are the amounts included in AOCI at December 31, 2024 and 2023 related to the other postretirement benefit plans of Southern Company, Southern Power, and Southern Company Gas that had not yet been recognized in net periodic other postretirement benefit cost.

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
Balance at December 31, 2024			
AOCI:			
Net (gain) loss	**$ (14)**	**$ —**	**$ (15)**
Balance at December 31, 2023			
AOCI:			
Prior service cost	$ 1	$ —	$ —
Net (gain) loss	(10)	1	(10)
Total AOCI	$ (9)	$ 1	$ (10)

The components of OCI related to the other postretirement benefit plans for the plan years ended December 31, 2024 and 2023 are presented in the following table:

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
AOCI:			
Balance at December 31, 2022	$ (4)	$ —	$ (2)
Net (gain) loss	(12)	1	—
Reclassification adjustments:			
Amortization of net gain (loss)	7	—	(8)
Total change	(5)	1	(8)
Balance at December 31, 2023	$ (9)	$ 1	$ (10)
Net gain	**(8)**	**(1)**	**(5)**
Reclassification adjustments:			
Amortization of net gain (loss)	**3**	**—**	**—**
Total change	**(5)**	**(1)**	**(5)**
Balance at December 31, 2024	**$ (14)**	**$ —**	**$ (15)**

Components of the other postretirement benefit plans' net periodic cost for the Registrants were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024						
Service cost	**$ 15**	**$ 4**	**$ 4**	**$ 1**	**$ —**	**$ 1**
Interest cost	**65**	**16**	**23**	**3**	**—**	**8**
Expected return on plan assets	**(89)**	**(35)**	**(32)**	**(3)**	**1**	**(13)**
Net amortization(*)	**(13)**	**(3)**	**(4)**	**—**	**—**	**6**
Net periodic other postretirement benefit cost (income)	**$ (22)**	**$ (18)**	**$ (9)**	**$ 1**	**$ 1**	**$ 2**
2023						
Service cost	$ 15	$ 4	$ 4	$ 1	$ —	$ 1
Interest cost	70	17	25	3	—	9
Expected return on plan assets	(83)	(33)	(29)	(3)	1	(10)
Net amortization(*)	(11)	(3)	(3)	—	—	6
Net periodic other postretirement benefit cost (income)	$ (9)	$ (15)	$ (3)	$ 1	$ 1	$ 6
2022						
Service cost	$ 23	$ 6	$ 6	$ 1	$ —	$ 1
Interest cost	42	10	15	2	—	5
Expected return on plan assets	(80)	(32)	(28)	(2)	1	(9)
Net amortization(*)	(1)	—	2	—	—	6
Net periodic other postretirement benefit cost (income)	$ (16)	$ (16)	$ (5)	$ 1	$ 1	$ 3

(*) For Southern Company, excludes amounts related to net periodic other postretirement benefit cost of $8 million for all years presented associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company.

The service cost component of net periodic other postretirement benefit cost is included in operations and maintenance expenses and all other components of net periodic other postretirement benefit cost are included in other income (expense), net in the Registrants' statements of income.

The Registrants' future benefit payments, including prescription drug benefits, are provided in the table below. These amounts reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Benefit payments:						
2025	$ 112	$ 24	$ 40	$ 5	$ 1	$ 16
2026	112	25	40	5	1	16
2027	113	26	41	5	1	15
2028	114	26	41	5	1	15
2029	114	27	42	5	1	14
2030 to 2034	558	133	205	22	1	61

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Registrants' investment policies for both the pension plans and the other postretirement benefit plans cover a diversified mix of assets as described below. Derivative instruments may be used to gain efficient exposure to the various asset classes and as hedging tools. Additionally, the Registrants minimize the risk of large losses primarily through diversification but also monitor and manage other aspects of risk.

The investment strategy for plan assets related to the Southern Company system's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Southern Company system employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Investment Strategies and Benefit Plan Asset Fair Values

A description of the major asset classes that the pension and other postretirement benefit plans are comprised of, along with the valuation methods used for fair value measurement, is provided below:

Description	Valuation Methodology
Domestic equity: A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches. **International equity:** A mix of large and small capitalization growth and value stocks with developed and emerging markets exposure, managed both actively and through fundamental indexing approaches.	Domestic and international equities such as common stocks, American depositary receipts, and real estate investment trusts that trade on public exchanges are classified as Level 1 investments and are valued at the closing price in the active market. Equity funds with unpublished prices that are comprised of publicly traded securities (such as commingled/pooled funds) are also valued at the closing price in the active market but are classified as Level 2.
Fixed income: A mix of domestic and international bonds.	Investments in fixed income securities, including fixed income pooled funds, are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
Trust-owned life insurance (TOLI): Investments of taxable trusts aimed at minimizing the impact of taxes on the portfolio.	Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate accounts. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
Real estate: Investments in equity or debt of real properties and in publicly traded real estate securities. **Special situations:** Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies, as well as investments in promising new strategies of a longer-term nature. **Private equity:** Investments in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt. **Private credit:** Investments focused on debt instruments, of which returns are driven by income rather than capital appreciation. **Infrastructure:** Investments in real assets, typically with long-term, predictable, and stable cash flows and a meaningful income component.	Investments in real estate, special situations, private equity, private credit, and infrastructure are typically invested in private partnerships and/or other pooled vehicles (Investment Funds) which are generally classified as Net Asset Value as a Practical Expedient, since the Investment Funds and underlying assets are not publicly traded and/or often have liquidity restrictions. The managers of the Investment Funds value the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The total market value of each of the Investment Funds is determined by aggregating the value of the underlying assets less liabilities.

For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate. The fair values presented herein exclude cash, receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

The fair values, and actual allocations relative to the target allocations, of the Southern Company system's pension plans at December 31, 2024 and 2023 are presented below.

	Fair Value Measurements Using					
At December 31, 2024:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**	**Target Allocation**	**Actual Allocation**

	(in millions)					
Southern Company						
Assets:						
Equity:					**41 %**	**41 %**
Domestic equity	**$ 2,095**	**$ 835**	**$ —**	**$ 2,930**		
International equity	**1,959**	**1,032**	**—**	**2,991**		
Fixed income:					**30**	**31**
U.S. Treasury, government, and agency bonds	**—**	**1,780**	**—**	**1,780**		
Mortgage- and asset-backed securities	**—**	**48**	**—**	**48**		
Corporate bonds	**—**	**1,715**	**—**	**1,715**		
Pooled funds	**—**	**792**	**—**	**792**		
Cash equivalents and other	**255**	**—**	**—**	**255**		
Real estate investments	**361**	**—**	**1,563**	**1,924**	**12**	**13**
Special situations	**—**	**—**	**237**	**237**	**3**	**2**
Private equity	**—**	**—**	**1,797**	**1,797**	**9**	**12**
Private credit	**—**	**—**	**152**	**152**	**3**	**1**
Infrastructure	**—**	**—**	**—**	**—**	**2**	**—**
Total	**$ 4,670**	**$ 6,202**	**$ 3,749**	**$ 14,621**	**100 %**	**100 %**
Liabilities:						
Derivatives	**$ —**	**$ (33)**	**$ —**	**$ (33)**		
Total	**$ 4,670**	**$ 6,169**	**$ 3,749**	**$ 14,588**	**100 %**	**100 %**
Alabama Power						
Assets:						
Equity:					**41 %**	**41 %**
Domestic equity	**$ 509**	**$ 203**	**$ —**	**$ 712**		
International equity	**476**	**251**	**—**	**727**		
Fixed income:					**30**	**31**
U.S. Treasury, government, and agency bonds	**—**	**433**	**—**	**433**		
Mortgage- and asset-backed securities	**—**	**12**	**—**	**12**		
Corporate bonds	**—**	**417**	**—**	**417**		
Pooled funds	**—**	**193**	**—**	**193**		
Cash equivalents and other	**62**	**—**	**—**	**62**		
Real estate investments	**88**	**—**	**380**	**468**	**12**	**13**
Special situations	**—**	**—**	**57**	**57**	**3**	**2**
Private equity	**—**	**—**	**437**	**437**	**9**	**12**
Private credit	**—**	**—**	**37**	**37**	**3**	**1**
Infrastructure	**—**	**—**	**—**	**—**	**2**	**—**
Total	**$ 1,135**	**$ 1,509**	**$ 911**	**$ 3,555**	**100 %**	**100 %**
Liabilities:						
Derivatives	**$ —**	**$ (8)**	**$ —**	**$ (8)**		
Total	**$ 1,135**	**$ 1,501**	**$ 911**	**$ 3,547**	**100 %**	**100 %**
Georgia Power						
Assets:						
Equity:					**41 %**	**41 %**
Domestic equity	**$ 652**	**$ 259**	**$ —**	**$ 911**		

International equity	608	320	—	928		
Fixed income:					30	31
U.S. Treasury, government, and agency bonds	—	552	—	552		
Mortgage- and asset-backed securities	—	15	—	15		
Corporate bonds	—	532	—	532		
Pooled funds	—	246	—	246		
Cash equivalents and other	79	—	—	79		
Real estate investments	112	—	485	597	12	13
Special situations	—	—	73	73	3	2
Private equity	—	—	558	558	9	12
Private credit	—	—	47	47	3	1
Infrastructure	—	—	—	—	2	—
Total	$ 1,451	$ 1,924	$ 1,163	$ 4,538	100 %	100 %
Liabilities:						
Derivatives	$ —	$ (10)	$ —	$ (10)		
Total	$ 1,451	$ 1,914	$ 1,163	$ 4,528	100 %	100 %
Mississippi Power						
Assets:						
Equity:					41 %	41 %
Domestic equity	$ 97	$ 38	$ —	$ 135		
International equity	89	47	—	136		
Fixed income:					30	31
U.S. Treasury, government, and agency bonds	—	81	—	81		
Mortgage- and asset-backed securities	—	2	—	2		
Corporate bonds	—	78	—	78		
Pooled funds	—	36	—	36		
Cash equivalents and other	12	—	—	12		
Real estate investments	16	—	71	87	12	13
Special situations	—	—	11	11	3	2
Private equity	—	—	82	82	9	12
Private credit	—	—	7	7	3	1
Infrastructure	—	—	—	—	2	—
Total	$ 214	$ 282	$ 171	$ 667	100 %	100 %
Liabilities:						
Derivatives	$ —	$ (2)	$ —	$ (2)		
Total	$ 214	$ 280	$ 171	$ 665	100 %	100 %
Southern Power						
Assets:						
Equity:					41 %	41 %
Domestic equity	$ 27	$ 11	$ —	$ 38		
International equity	25	13	—	38		
Fixed income:					30	31
U.S. Treasury, government, and agency bonds	—	23	—	23		
Mortgage- and asset-backed securities	—	1	—	1		
Corporate bonds	—	22	—	22		

Pooled funds	—	10	—	10		
Cash equivalents and other	3	—	—	3		
Real estate investments	5	—	20	25	12	13
Special situations	—	—	3	3	3	2
Private equity	—	—	23	23	9	12
Private credit	—	—	2	2	3	1
Infrastructure	—	—	—	—	2	—
Total	$ 60	$ 80	$ 48	$ 188	100 %	100 %
Southern Company Gas						
Assets:						
Equity:					41 %	41 %
Domestic equity	$ 142	$ 56	$ —	$ 198		
International equity	132	69	—	201		
Fixed income:					30	31
U.S. Treasury, government, and agency bonds	—	120	—	120		
Mortgage- and asset-backed securities	—	3	—	3		
Corporate bonds	—	115	—	115		
Pooled funds	—	53	—	53		
Cash equivalents and other	17	—	—	17		
Real estate investments	24	—	105	129	12	13
Special situations	—	—	16	16	3	2
Private equity	—	—	121	121	9	12
Private credit	—	—	10	10	3	1
Infrastructure	—	—	—	—	2	—
Total	$ 315	$ 416	$ 252	$ 983	100 %	100 %
Liabilities:						
Derivatives	$ —	$ (2)	$ —	$ (2)		
Total	$ 315	$ 414	$ 252	$ 981	100 %	100 %

At December 31, 2023:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Company						
Assets:						
Equity:					41 %	40 %
Domestic equity	$ 1,959	$ 771	$ —	$ 2,730		
International equity	1,947	1,052	—	2,999		
Fixed income:					30	32
U.S. Treasury, government, and agency bonds	—	1,973	—	1,973		
Mortgage- and asset-backed securities	—	44	—	44		
Corporate bonds	—	1,724	—	1,724		
Pooled funds	—	777	—	777		
Cash equivalents and other	371	58	—	429		
Real estate investments	369	—	1,684	2,053	12	14
Special situations	—	—	245	245	3	2
Private equity	—	—	1,761	1,761	9	12
Private Credit	—	—	25	25	3	—
Infrastructure	—	—	—	—	2	—
Total	$ 4,646	$ 6,399	$ 3,715	$ 14,760	100 %	100 %
Alabama Power						
Assets:						
Equity:					41 %	40 %
Domestic equity	$ 476	$ 187	$ —	$ 663		
International equity	472	255	—	727		
Fixed income:					30	32
U.S. Treasury, government, and agency bonds	—	479	—	479		
Mortgage- and asset-backed securities	—	11	—	11		
Corporate bonds	—	418	—	418		
Pooled funds	—	188	—	188		
Cash equivalents and other	90	14	—	104		
Real estate investments	89	—	408	497	12	14
Special situations	—	—	59	59	3	2
Private equity	—	—	427	427	9	12
Private credit	—	—	6	6	3	—
Infrastructure	—	—	—	—	2	—
Total	$ 1,127	$ 1,552	$ 900	$ 3,579	100 %	100 %
Georgia Power						
Assets:						
Equity:					41 %	40 %
Domestic equity	$ 611	$ 241	$ —	$ 852		

International equity	609	329	—	938		
Fixed income:					30	32
U.S. Treasury, government, and agency bonds	—	617	—	617		
Mortgage- and asset-backed securities	—	14	—	14		
Corporate bonds	—	539	—	539		
Pooled funds	—	243	—	243		
Cash equivalents and other	116	18	—	134		
Real estate investments	115	—	527	642	12	14
Special situations	—	—	77	77	3	2
Private equity	—	—	551	551	9	12
Private credit	—	—	8	8	3	—
Infrastructure	—	—	—	—	2	—
Total	$ 1,451	$ 2,001	$ 1,163	$ 4,615	100 %	100 %
Mississippi Power						
Assets:						
Equity:					41 %	40 %
Domestic equity	$ 89	$ 35	$ —	$ 124		
International equity	89	48	—	137		
Fixed income:					30	32
U.S. Treasury, government, and agency bonds	—	90	—	90		
Mortgage- and asset-backed securities	—	2	—	2		
Corporate bonds	—	79	—	79		
Pooled funds	—	36	—	36		
Cash equivalents and other	17	3	—	20		
Real estate investments	17	—	77	94	12	14
Special situations	—	—	11	11	3	2
Private equity	—	—	81	81	9	12
Private credit	—	—	1	1	3	—
Infrastructure	—	—	—	—	2	—
Total	$ 212	$ 293	$ 170	$ 675	100 %	100 %
Southern Power						
Assets:						
Equity:					41 %	40 %
Domestic equity	$ 24	$ 10	$ —	$ 34		
International equity	25	13	—	38		
Fixed income:					30	32
U.S. Treasury, government, and agency bonds	—	25	—	25		
Mortgage - and asset backed securities	—	1	—	1		
Corporate bonds	—	22	—	22		
Pooled funds	—	10	—	10		
Cash equivalents and other	5	1	—	6		
Real estate investments	5	—	21	26	12	14

Special situations	—	—	3	3	3	2
Private equity	—	—	22	22	9	12
Private credit	—	—	—	—	3	—
Infrastructure	—	—	—	—	2	—
Total	$ 59	$ 82	$ 46	$ 187	100 %	100 %
Southern Company Gas						
Assets:						
Equity:					41 %	40 %
Domestic equity	$ 130	$ 52	$ —	$ 182		
International equity	130	71	—	201		
Fixed income:					30	32
U.S. Treasury, government, and agency bonds	—	132	—	132		
Mortgage- and asset-backed securities	—	3	—	3		
Corporate bonds	—	116	—	116		
Pooled funds	—	52	—	52		
Cash equivalents and other	25	4	—	29		
Real estate investments	25	—	113	138	12	14
Special situations	—	—	16	16	3	2
Private equity	—	—	118	118	9	12
Private credit	—	—	2	2	3	—
Infrastructure	—	—	—	—	2	—
Total	$ 310	$ 430	$ 249	$ 989	100 %	100 %

The fair values, and actual allocations relative to the target allocations, of the applicable Registrants' other postretirement benefit plan assets at December 31, 2024 and 2023 are presented below.

At December 31, 2024:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Company						
Assets:						
Equity:					**61 %**	**62 %**
Domestic equity	**$ 94**	**$ 98**	**$ —**	**$ 192**		
International equity	**54**	**83**	**—**	**137**		
Fixed income:					**29**	**28**
U.S. Treasury, government, and agency bonds	**—**	**54**	**—**	**54**		
Mortgage- and asset-backed securities	**—**	**1**	**—**	**1**		
Corporate bonds	**—**	**48**	**—**	**48**		
Pooled funds	**—**	**99**	**—**	**99**		
Cash equivalents and other	**16**	**—**	**—**	**16**		
Trust-owned life insurance	**—**	**478**	**—**	**478**		
Real estate investments	**11**	**—**	**43**	**54**	**4**	**5**
Special situations	**—**	**—**	**6**	**6**	**1**	**1**
Private equity	**—**	**—**	**50**	**50**	**3**	**4**
Private credit	**—**	**—**	**4**	**4**	**1**	**—**
Infrastructure	**—**	**—**	**—**	**—**	**1**	**—**
Total	**$ 175**	**$ 861**	**$ 103**	**$ 1,139**	**100 %**	**100 %**
Liabilities:						
Derivatives	**$ —**	**$ (1)**	**$ —**	**$ (1)**		
Total	**$ 175**	**$ 860**	**$ 103**	**$ 1,138**	**100 %**	**100 %**
Alabama Power						
Assets:						
Equity:					**68 %**	**68 %**
Domestic equity	**$ 17**	**$ 7**	**$ —**	**$ 24**		
International equity	**16**	**9**	**—**	**25**		
Fixed income:					**23**	**24**
U.S. Treasury, government, and agency bonds	**—**	**14**	**—**	**14**		
Corporate bonds	**—**	**14**	**—**	**14**		
Pooled funds	**—**	**11**	**—**	**11**		
Cash equivalents and other	**2**	**—**	**—**	**2**		
Trust-owned life insurance	**—**	**294**	**—**	**294**		
Real estate investments	**3**	**—**	**13**	**16**	**3**	**4**
Special situations	**—**	**—**	**2**	**2**	**1**	**1**
Private equity	**—**	**—**	**15**	**15**	**3**	**3**

Private credit	—	—	1	1	1	—
Infrastructure	—	—	—	—	1	—
Total	$ 38	$ 349	$ 31	$ 418	100 %	100 %
Georgia Power						
Assets:						
Equity:					59 %	59 %
Domestic equity	$ 52	$ 7	$ —	$ 59		
International equity	16	41	—	57		
Fixed income:					35	33
U.S. Treasury, government, and agency bonds	—	14	—	14		
Corporate bonds	—	14	—	14		
Pooled funds	—	48	—	48		
Cash equivalents and other	10	—	—	10		
Trust-owned life insurance	—	184	—	184		
Real estate investments	4	—	13	17	3	4
Special situations	—	—	2	2	1	1
Private equity	—	—	15	15	2	3
Total	$ 82	$ 308	$ 30	$ 420	100 %	100 %
Mississippi Power						
Assets:						
Equity:					34 %	32 %
Domestic equity	$ 3	$ 1	$ —	$ 4		
International equity	3	1	—	4		
Fixed income:					43	44
U.S. Treasury, government, and agency bonds	—	7	—	7		
Corporate bonds	—	2	—	2		
Pooled funds	—	1	—	1		
Cash equivalents and other	1	—	—	1		
Real estate investments	—	—	2	2	10	11
Special situations	—	—	—	—	2	2
Private equity	—	—	2	2	7	10
Private credit	—	—	—	—	3	1
Infrastructure	—	—	—	—	1	—
Total	$ 7	$ 12	$ 4	$ 23	100 %	100 %
Southern Company Gas						
Assets:						
Equity:					72 %	73 %
Domestic equity	$ 1	$ 76	$ —	$ 77		
International equity	1	23	—	24		
Fixed income:					26	25
U.S. Treasury, government, and agency bonds	—	1	—	1		
Corporate bonds	—	1	—	1		
Pooled funds	—	32	—	32		
Cash equivalents and other	1	—	—	1		
Real estate investments	—	—	1	1	1	1
Private equity	—	—	1	1	1	1
Total	$ 3	$ 133	$ 2	$ 138	100 %	100 %

At December 31, 2023:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Company						
Assets:						
Equity:					60 %	61 %
Domestic equity	$ 85	$ 87	$ —	$ 172		
International equity	53	82	—	135		
Fixed income:					30	28
U.S. Treasury, government, and agency bonds	—	57	—	57		
Mortgage- and asset-backed securities	—	2	—	2		
Corporate bonds	—	47	—	47		
Pooled funds	—	92	—	92		
Cash equivalents and other	21	2	—	23		
Trust-owned life insurance	—	456	—	456		
Real estate investments	11	—	46	57	4	6
Special situations	—	—	6	6	1	1
Private equity	—	—	48	48	3	4
Private credit	—	—	1	1	1	—
Infrastructure	—	—	—	—	1	—
Total	$ 170	$ 825	$ 101	$ 1,096	100 %	100 %
Alabama Power						
Assets:						
Equity:					67 %	66 %
Domestic equity	$ 16	$ 6	$ —	$ 22		
International equity	16	9	—	25		
Fixed income:					23	23
U.S. Treasury, government, and agency bonds	—	16	—	16		
Corporate bonds	—	14	—	14		
Pooled funds	—	8	—	8		
Cash equivalents and other	3	—	—	3		
Trust-owned life insurance	—	280	—	280		
Real estate investments	3	—	14	17	4	6
Special situations	—	—	2	2	1	1
Private equity	—	—	15	15	3	4
Private credit	—	—	—	—	1	—
Infrastructure	—	—	—	—	1	—
Total	$ 38	$ 333	$ 31	$ 402	100 %	100 %
Georgia Power						
Assets:						

Equity:					58 %	57 %
Domestic equity	$ 47	$ 6	$ —	$ 53		
International equity	16	40	—	56		
Fixed income:					35	35
U.S. Treasury, government, and agency bonds	—	16	—	16		
Corporate bonds	—	14	—	14		
Pooled funds	—	47	—	47		
Cash equivalents and other	13	—	—	13		
Trust-owned life insurance	—	176	—	176		
Real estate investments	4	—	14	18	3	4
Special situations	—	—	2	2	1	1
Private equity	—	—	14	14	2	3
Private credit	—	—	—	—	1	—
Total	$ 80	$ 299	$ 30	$ 409	100 %	100 %
Mississippi Power						
Assets:						
Equity:					34 %	33 %
Domestic equity	$ 3	$ 1	$ —	$ 4		
International equity	3	1	—	4		
Fixed income:					43	44
U.S. Treasury, government, and agency bonds	—	7	—	7		
Corporate bonds	—	2	—	2		
Pooled funds	—	1	—	1		
Cash equivalents and other	1	—	—	1		
Real estate investments	1	—	2	3	10	11
Special situations	—	—	—	—	2	2
Private equity	—	—	2	2	7	10
Private credit	—	—	—	—	3	—
Infrastructure	—	—	—	—	1	—
Total	$ 8	$ 12	$ 4	$ 24	100 %	100 %
Southern Company Gas						
Assets:						
Equity:					72 %	72 %
Domestic equity	$ 2	$ 67	$ —	$ 69		
International equity	2	22	—	24		
Fixed income:					26	26
U.S. Treasury, government, and agency bonds	—	1	—	1		
Corporate bonds	—	1	—	1		
Pooled funds	—	29	—	29		
Cash equivalents and other	1	—	—	1		
Real estate investments	—	—	1	1	1	1
Private equity	—	—	1	1	1	1
Total	$ 5	$ 120	$ 2	$ 127	100 %	100 %

Employee Savings Plan

Southern Company and its subsidiaries also sponsor 401(k) defined contribution plans covering substantially all employees and provide matching contributions up to specified percentages of an employee's eligible pay. Total matching contributions made to the plans for 2024, 2023, and 2022 were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2024	**$ 137**	**$ 29**	**$ 31**	**$ 5**	**$ 3**	**$ 20**
2023	131	28	31	5	3	18
2022	124	26	29	5	3	17

12. STOCK COMPENSATION

Stock-based compensation in the form of Southern Company performance share units (PSU) and restricted stock units (RSU) may be granted through the Equity and Incentive Compensation Plan to eligible Southern Company system employees.

At December 31, 2024, the number of current and former employees participating in stock-based compensation programs for the Registrants was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Number of employees	1,154	158	161	36	36	183

The majority of PSUs and RSUs awarded contain terms where employees become immediately vested in PSUs and RSUs upon retirement. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately, while compensation expense for employees that are expected to become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. In addition, the Registrants recognize forfeitures as they occur.

All unvested PSUs and RSUs vest immediately upon a change in control where Southern Company is not the surviving corporation. Stock-based compensation activity is immaterial for the Subsidiary Registrants.

Performance Share Units

PSUs granted to employees vest at the end of a three-year performance period. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of PSUs granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company has issued two types of PSUs, each with a unique performance goal. These types of PSUs include total shareholder return (TSR) awards based on the TSR for Southern Company common stock during the three-year performance period as compared to a group of industry peers and ROE awards based on Southern Company's equity-weighted return over the performance period.

The fair value of TSR awards is determined as of the grant date using a Monte Carlo simulation model. In determining the fair value of the TSR awards issued to employees, the expected volatility is based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate is based on the U.S. Treasury yield curve in effect at the

time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of TSR awards granted:

Year Ended December 31	2024	2023	2022
Expected volatility	**19.1%**	30.0%	29.6%
Interest rate	**4.0%**	3.8%	1.7%
Weighted average grant-date fair value	**$80.99**	$76.83	$79.69

The Registrants recognize TSR award compensation expense on a straight-line basis over the three-year performance period without remeasurement.

The fair values of ROE awards are based on the closing stock price of Southern Company common stock on the date of the grant. The weighted average grant-date fair value of the ROE awards granted during 2024, 2023, and 2022 was $69.67, $68.93, and $66.87, respectively. Compensation expense for ROE awards is generally recognized ratably over the three-year performance period adjusted for expected changes in ROE performance. Total compensation cost recognized for vested ROE awards reflects final performance metrics.

Southern Company had 2.4 million unvested PSUs outstanding at December 31, 2023. In February 2024, the PSUs that vested for the three-year performance period ended December 31, 2023 were converted into 2.3 million shares outstanding at a share price of $66.95. During 2024, Southern Company granted 1.1 million PSUs and 1.2 million PSUs were vested or forfeited, resulting in 2.3 million unvested PSUs outstanding at December 31, 2024. In February 2025, the PSUs that vested for the three-year performance period ended December 31, 2024 were converted into 2.0 million shares outstanding at a weighted average share price of $83.87.

Southern Company's total PSU compensation cost and the related tax benefit recognized in income for the years ended December 31, 2024, 2023, and 2022 were as follows:

	2024	2023	2022
		(in millions)	
Compensation cost recognized in income	**$ 102**	$ 107	$ 101
Tax benefit of compensation cost recognized in income	**27**	28	26

The compensation cost related to the grant of Southern Company PSUs to the employees of each Subsidiary Registrant is recognized in each Subsidiary Registrant's financial statements with a corresponding credit to equity representing a capital contribution from Southern Company.

At December 31, 2024, Southern Company's total unrecognized compensation cost related to PSUs was $33 million and is expected to be recognized over a weighted-average period of approximately 19 months.

Restricted Stock Units

The fair value of RSUs is based on the closing stock price of Southern Company common stock on the date of the grant. The weighted average grant-date fair values of RSUs granted during 2024, 2023, and 2022 were $70.49, $68.95, and $67.20, respectively. For most RSU awards, one-third of the RSUs vest each year throughout a three-year service period and compensation cost for RSUs is generally recognized over the corresponding one-, two-, or three-year vesting period. Shares of Southern Company common stock are delivered to employees at the end of each vesting period.

Southern Company had 0.9 million RSUs outstanding at December 31, 2023. During 2024, Southern Company granted 0.5 million RSUs and 0.5 million RSUs were vested or forfeited, resulting in 0.9 million unvested RSUs outstanding at December 31, 2024, including RSUs related to employee retention agreements.

Southern Company's total RSU compensation cost and the related tax benefit recognized in income for the years ended December 31, 2024, 2023, and 2022 were as follows:

	2024	2023	2022
		(in millions)	
Compensation cost recognized in income	**$ 30**	$ 30	$ 26
Tax benefit of compensation cost recognized in income	**8**	8	7

Total unrecognized compensation cost related to RSUs at December 31, 2024, which is being recognized over a weighted-average period of approximately 19 months, was immaterial for Southern Company.

The compensation cost related to the grant of Southern Company RSUs to the employees of each Subsidiary Registrant is recognized in such Subsidiary Registrant's financial statements with a corresponding credit to equity representing a capital contribution from Southern Company.

Stock Options

In 2015, Southern Company discontinued granting stock options. As of December 31, 2017, all stock option awards were vested and compensation cost fully recognized and the last exercise occurred in November 2024.

Southern Company's cash receipts from issuances related to stock options exercised under the share-based payment arrangements for the years ended December 31, 2024, 2023, and 2022 were $14 million, $28 million, and $75 million, respectively.

Southern Company's total intrinsic value of options exercised and the related tax benefit for the years ended December 31, 2024, 2023, and 2022 were as follows:

	2024	2023	2022
		(in millions)	
Intrinsic value of options exercised	**$ 10**	$ 18	$ 49
Tax benefit of options exercised	**2**	4	12

13. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of each Registrant of what a market participant would use in pricing an asset or liability. If there is little available market data, then each Registrant's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

Net asset value as a practical expedient is the classification used for assets that do not have readily determined fair values. Fund managers value the assets using various inputs and techniques depending on the nature of the underlying investments.

At December 31, 2024, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using				
At December 31, 2024:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**
			(in millions)		
Southern Company					
Assets:					
Energy-related derivatives[a]	$ 12	$ 77	$ —	$ —	$ 89
Investments in trusts:[b]					
Domestic equity	849	250	—	—	1,099
Foreign equity	148	175	—	—	323
U.S. Treasury and government agency securities	—	371	—	—	371
Municipal bonds	—	47	—	—	47
Pooled funds – fixed income	—	7	—	—	7
Corporate bonds	—	452	—	—	452
Mortgage and asset backed securities	—	106	—	—	106
Private equity	—	—	—	181	181
Cash and cash equivalents	1	—	—	—	1
Other	39	3	—	9	51
Investments, available for sale:					
U.S. Treasury and government agency securities	2	7	—	—	9
Corporate bonds	1	2	—	—	3
Mortgage and asset backed securities	—	10	—	—	10
Cash equivalents and restricted cash	533	19	—	—	552
Other investments	9	31	8	—	48
Total	$ 1,594	$ 1,557	$ 8	$ 190	$ 3,349
Liabilities:					
Energy-related derivatives[a]	$ 5	$ 124	$ —	$ —	$ 129
Interest rate derivatives	—	269	—	—	269
Foreign currency derivatives	—	218	—	—	218
Contingent consideration	3	—	16	—	19
Other	—	13	11	—	24
Total	$ 8	$ 624	$ 27	$ —	$ 659
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 26	$ —	$ —	$ 26
Nuclear decommissioning trusts:[b]					
Domestic equity	459	241	—	—	700
Foreign equity	148	—	—	—	148
U.S. Treasury and government agency securities	—	16	—	—	16

Municipal bonds	—	1	—	—	1
Corporate bonds	—	287	—	—	287
Mortgage and asset backed securities	—	31	—	—	31
Private equity	—	—	—	181	181
Other	11	1	—	9	21
Cash equivalents and restricted cash	334	19	—	—	353
Other investments	—	31	—	—	31
Total	$ 952	$ 653	$ —	$ 190	$ 1,795
Liabilities:					
Energy-related derivatives	$ —	$ 42	$ —	$ —	$ 42
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 19	$ —	$ —	$ 19
Nuclear decommissioning trusts:[b]					
Domestic equity	390	1	—	—	391
Foreign equity	—	174	—	—	174
U.S. Treasury and government agency securities	—	355	—	—	355
Municipal bonds	—	46	—	—	46
Corporate bonds	—	165	—	—	165
Mortgage and asset backed securities	—	75	—	—	75
Other	28	2	—	—	30
Cash equivalents	35	—	—	—	35
Total	$ 453	$ 837	$ —	$ —	$ 1,290
Liabilities:					
Energy-related derivatives	$ —	$ 42	$ —	$ —	$ 42
Mississippi Power					
Assets:					
Energy-related derivatives	$ —	$ 19	$ —	$ —	$ 19
Liabilities:					
Energy-related derivatives	$ —	$ 34	$ —	$ —	$ 34
Southern Power					
Assets:					
Energy-related derivatives	$ —	$ 4	$ —	$ —	$ 4
Cash equivalents	51	—	—	—	51
Total	$ 51	$ 4	$ —	$ —	$ 55
Liabilities:					
Foreign currency derivatives	$ —	$ 51	$ —	$ —	$ 51
Contingent consideration	3	—	16	—	19
Other	—	13	11	—	24
Total	$ 3	$ 64	$ 27	$ —	$ 94
Southern Company Gas					
Assets:					
Energy-related derivatives[a]	$ 12	$ 9	$ —	$ —	$ 21
Non-qualified deferred compensation trusts:					
Domestic equity	—	8	—	—	8
Foreign equity	—	1	—	—	1
Pooled funds - fixed income	—	7	—	—	7
Cash and cash equivalents	1	—	—	—	1
Investments, available for sale:					
U.S. Treasury and government agency securities	2	7	—	—	9
Corporate bonds	1	2	—	—	3
Mortgage and asset backed securities	—	10	—	—	10
Cash equivalents	22	—	—	—	22
Total	$ 38	$ 44	$ —	$ —	$ 82
Liabilities:					
Energy-related derivatives[a]	$ 5	$ 6	$ —	$ —	$ 11
Interest rate derivatives	—	84	—	—	84
Total	$ 5	$ 90	$ —	$ —	$ 95

(a) Excludes cash collateral of $17 million.

(b) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies. See Note 6 under "Nuclear Decommissioning" for additional information.

At December 31, 2023, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

At December 31, 2023:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Southern Company					
Assets:					
Energy-related derivatives[a]	$ 6	$ 49	$ —	$ —	$ 55
Investments in trusts:[b]					
Domestic equity	764	216	—	—	980
Foreign equity	145	171	—	—	316
U.S. Treasury and government agency securities	—	369	—	—	369
Municipal bonds	—	48	—	—	48
Pooled funds – fixed income	—	6	—	—	6
Corporate bonds	—	389	—	—	389
Mortgage and asset backed securities	—	89	—	—	89
Private equity	—	—	—	169	169
Cash and cash equivalents	3	—	—	—	3
Other	58	3	—	9	70
Cash equivalents and restricted cash	253	15	—	—	268
Other investments	9	27	8	—	44
Total	$ 1,238	$ 1,382	$ 8	$ 178	$ 2,806
Liabilities:					

Energy-related derivatives[a]	$ 46	$ 312	$ —	$ —	$ 358
Interest rate derivatives	—	264	—	—	264
Foreign currency derivatives	—	122	—	—	122
Contingent consideration	3	—	16	—	19
Other	—	13	—	—	13
Total	$ 49	$ 711	$ 16	$ —	$ 776
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 15	$ —	$ —	$ 15
Nuclear decommissioning trusts:[b]					
Domestic equity	443	208	—	—	651
Foreign equity	145	—	—	—	145
U.S. Treasury and government agency securities	—	20	—	—	20
Municipal bonds	—	1	—	—	1
Corporate bonds	—	231	—	—	231
Mortgage and asset backed securities	—	25	—	—	25
Private equity	—	—	—	169	169
Other	8	—	—	9	17
Cash equivalents and restricted cash	119	15	—	—	134
Other investments	—	27	—	—	27
Total	$ 715	$ 542	$ —	$ 178	$ 1,435
Liabilities:					
Energy-related derivatives	$ —	$ 110	$ —	$ —	$ 110
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 13	$ —	$ —	$ 13
Nuclear decommissioning trusts:[b]					
Domestic equity	321	1	—	—	322
Foreign equity	—	170	—	—	170
U.S. Treasury and government agency securities	—	349	—	—	349
Municipal bonds	—	47	—	—	47
Corporate bonds	—	158	—	—	158
Mortgage and asset backed securities	—	64	—	—	64
Other	50	3	—	—	53
Total	$ 371	$ 805	$ —	$ —	$ 1,176
Liabilities:					
Energy-related derivatives	$ —	$ 124	$ —	$ —	$ 124
Mississippi Power					
Assets:					
Energy-related derivatives	$ —	$ 15	$ —	$ —	$ 15
Cash equivalents	17	—	—	—	17
Total	$ 17	$ 15	$ —	$ —	$ 32
Liabilities:					

Energy-related derivatives	$ —	$ 61	$ —	$ —	$ 61
Southern Power					
Assets:					
Energy-related derivatives	$ —	$ 3	$ —	$ —	$ 3
Liabilities:					
Energy-related derivatives	$ —	$ 5	$ —	$ —	$ 5
Foreign currency derivatives	—	22	—	—	22
Contingent consideration	3	—	16	—	19
Other	—	13	—	—	13
Total	$ 3	$ 40	$ 16	$ —	$ 59
Southern Company Gas					
Assets:					
Energy-related derivatives[a]	$ 6	$ 3	$ —	$ —	$ 9
Non-qualified deferred compensation trusts:					
Domestic equity	—	7	—	—	7
Foreign equity	—	1	—	—	1
Pooled funds - fixed income	—	6	—	—	6
Cash and cash equivalents	3	—	—	—	3
Total	$ 9	$ 17	$ —	$ —	$ 26
Liabilities:					
Energy-related derivatives[a]	$ 46	$ 12	$ —	$ —	$ 58
Interest rate derivatives	—	79	—	—	79
Total	$ 46	$ 91	$ —	$ —	$ 137

(a) Excludes cash collateral of $62 million.

(b) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies. See Note 6 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and OTC financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard OTC products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and, occasionally, implied volatility of interest rate options. The fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 14 for additional information on how these derivatives are used.

For fair value measurements of the investments within the nuclear decommissioning trusts and the non-qualified deferred compensation trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets

within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. See Note 6 under "Nuclear Decommissioning" for additional information.

Southern Power has contingent payment obligations related to two of its acquisitions whereby it is primarily obligated to make generation-based payments to the seller, commencing at the commercial operation of each facility and continuing through 2026 and 2036, respectively. The obligations are primarily categorized as Level 3 under Fair Value Measurements as the fair value is determined using significant unobservable inputs for the forecasted facility's generation in MW-hours, as well as other inputs such as a fixed dollar amount per MW-hour, and a discount rate. The fair value of the obligations reflects the net present value of expected payments and any periodic change arising from forecasted generation is expected to be immaterial.

Southern Power also has payment obligations through 2040 whereby it must reimburse the transmission owners for interconnection facilities and network upgrades constructed to support connection of a Southern Power generating facility to the transmission system. The obligations are categorized as Level 2 under Fair Value Measurements as the fair value is determined using observable inputs for the contracted amounts and reimbursement period, as well as a discount rate. The fair value of the obligations reflects the net present value of expected payments.

"Other investments" primarily includes investments traded in the open market that have maturities greater than 90 days, which are categorized as Level 2 under Fair Value Measurements and are comprised of corporate bonds, bank certificates of deposit, treasury bonds, and/or agency bonds.

The fair value measurements of private market investments held in Alabama Power's nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient totaled $190 million and $178 million at December 31, 2024 and 2023, respectively. Unfunded commitments related to the private market investments totaled $78 million and $87 million at December 31, 2024 and 2023, respectively. Private market investments include high-quality private equity funds across several market sectors, funds that invest in real estate assets, and a private credit fund. Private market funds do not have redemption rights. Distributions from these funds will be received as the underlying investments in the funds are liquidated.

Southern Company Gas' investments, available for sale relate to a wholly-owned subsidiary that insures various risk exposures of Southern Company Gas and its subsidiaries. Corporate and municipal bonds, government agency securities, and commercial paper are valued using pricing models maximizing the use of observable inputs for similar securities, including basing value on yields currently available on comparable securities of issues with similar credit ratings. Mortgage and asset backed securities are valued through an analysis of the underlying assets and a review of the documentation, including financials, the manager's valuation methodology in valuing their underlying assets, the types of assets and risks involved, and the investor's exit and termination parameters.

At December 31, 2024 and 2023, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas(*)
			(in billions)			
At December 31, 2024:						
Long-term debt, including securities due within one year:						
Carrying amount	**$ 63.2**	**$ 11.2**	**$ 18.1**	**$ 1.7**	**$ 2.7**	**$ 8.5**
Fair value	**57.7**	**9.8**	**16.2**	**1.5**	**2.6**	**7.4**
At December 31, 2023:						
Long-term debt, including securities due within one year:						
Carrying amount	$ 59.4	$ 11.2	$ 16.5	$ 1.6	$ 2.7	$ 7.8
Fair value	55.0	10.1	15.1	1.4	2.6	6.8

(*) The carrying amount of Southern Company Gas' long-term debt includes fair value adjustments from the effective date of the 2016 merger with Southern Company. Southern Company Gas amortizes the fair value adjustments over the remaining lives of the respective bonds, the latest being through 2043.

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Registrants.

14. DERIVATIVES

The Registrants are exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 13 for additional fair value information. In the statements of cash flows, any cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities. Any cash impacts of settled foreign currency derivatives are classified as operating or financing activities to correspond with the classification of the hedged interest or principal, respectively. See Note 1 under "Financial Instruments" for additional information.

Energy-Related Derivatives

The Subsidiary Registrants enter into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional electric operating companies and the natural gas distribution utilities have limited exposure to market volatility in energy-related commodity prices. Each of the traditional electric operating companies and certain of the natural gas distribution utilities of Southern Company Gas manage fuel-hedging programs, implemented per the guidelines of their respective state PSCs or other applicable state regulatory agencies, through the use of financial derivative contracts, which are expected to continue to mitigate price volatility. The traditional electric operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in energy-related commodity prices because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional electric operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted capacity is used to sell electricity. Southern Company Gas retains exposure to price changes that can, in a volatile energy market, be material and can adversely affect its results of operations.

Southern Company Gas also enters into weather derivative contracts as economic hedges in the event of warmer-than-normal weather. Exchange-traded options are carried at fair value, with changes reflected in natural gas revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are reflected in natural gas revenues.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts designated as regulatory hedges relate primarily to the traditional electric operating companies' and the natural gas distribution utilities' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through an approved cost recovery mechanism.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in AOCI before being recognized in the statements of income in the same period and in the same income statement line item as the earnings effect of the hedged transactions.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric and natural gas industries. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2024, the net volume of energy-related derivative contracts for natural gas positions, together with the longest hedge date over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company(*)	431	2030	2028
Alabama Power	123	2027	—
Georgia Power	116	2027	—
Mississippi Power	103	2028	—
Southern Power	6	2030	2025
Southern Company Gas(*)	83	2027	2028

(*) Southern Company Gas' derivative instruments include both long and short natural gas positions. A long position is a contract to purchase natural gas and a short position is a contract to sell natural gas. Southern Company Gas' volume represents the net of long natural gas positions of 90 million mmBtu and short natural gas positions of 7 million mmBtu at December 31, 2024, which is also included in Southern Company's total volume.

In addition to the volumes discussed above, the traditional electric operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess natural gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 15 million mmBtu for Southern Company, which includes 4 million mmBtu for Alabama Power, 6 million mmBtu for Georgia Power, 2 million mmBtu for Mississippi Power, and 3 million mmBtu for Southern Power.

For cash flow hedges of energy-related derivatives, the estimated pre-tax gains (losses) expected to be reclassified from AOCI to earnings for the year ending December 31, 2025 are immaterial for Southern Company, Southern Power, and Southern Company Gas.

Interest Rate Derivatives

Southern Company and certain subsidiaries may enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the

derivatives' fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time and presented on the same income statement line item as the earnings effect of the hedged transactions. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings on the same income statement line item. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

At December 31, 2024, the following interest rate derivatives were outstanding:

	Notional Amount	Weighted Average Interest Rate Paid	Interest Rate Received	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2024
	(in millions)				*(in millions)*
Fair Value Hedges of Existing Debt					
Southern Company parent	$ 400	1-month SOFR + 0.80%	1.75%	March 2028	$ (42)
Southern Company parent	1,000	1-month SOFR + 2.48%	3.70%	April 2030	(143)
Southern Company Gas	500	1-month SOFR + 0.49%	1.75%	January 2031	(84)
Southern Company	$ 1,900				$ (269)

For cash flow hedges of interest rate derivatives, the estimated pre-tax gains (losses) expected to be reclassified from AOCI to interest expense for the year ending December 31, 2025 are $(13) million for Southern Company and immaterial for the traditional electric operating companies and Southern Company Gas. Deferred gains and losses related to interest rate derivatives are expected to be amortized into earnings through 2054 for Southern Company, Georgia Power, and Mississippi Power, 2052 for Alabama Power, and 2046 for Southern Company Gas.

Foreign Currency Derivatives

Southern Company and certain subsidiaries, including Southern Power, may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates, such as that arising from the issuance of debt denominated in a currency other than U.S. dollars. Derivatives related to forecasted transactions are accounted for as cash flow hedges where the derivatives' fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time and on the same income statement line as the earnings effect of the hedged transactions, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings on the same income statement line item, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. Southern Company has elected to exclude the cross-currency basis spread from the assessment of effectiveness in the fair value hedges of its foreign currency risk and record any difference between the change in the fair value of the excluded components and the amounts recognized in earnings as a component of OCI.

At December 31, 2024, the following foreign currency derivatives were outstanding:

	Pay Notional	Pay Rate	Receive Notional	Receive Rate	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2024
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
Southern Power	$ 564	3.78%	€ 500	1.85%	June 2026	$ (51)
Fair Value Hedges of Existing Debt						
Southern Company parent	1,476	3.39%	1,250	1.88%	September 2027	(167)
Southern Company	$ 2,040		€ 1,750			$ (218)

For cash flow hedges of foreign currency derivatives, the estimated pre-tax losses expected to be reclassified from AOCI to earnings for the year ending December 31, 2025 are $25 million for Southern Power.

Derivative Financial Statement Presentation and Amounts

The Registrants enter into derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Southern Company and certain subsidiaries also utilize master netting agreements to mitigate exposure to counterparty credit risk. These agreements may contain provisions that permit netting across product lines and against cash collateral. The fair value amounts of derivative assets and liabilities on the balance sheets are presented net to the extent that there are netting arrangements or similar agreements with the counterparties.

The fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected as either assets or liabilities in the balance sheets (included in "Other" or shown separately as "Risk Management Activities") as follows:

Derivative Category and Balance Sheet Location	2024		2023	
	Assets	Liabilities	Assets	Liabilities
		(in millions)		
Southern Company				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Current	**$ 33**	**$ 82**	$ 12	$ 198
Non-current	**42**	**40**	31	117
Total derivatives designated as hedging instruments for regulatory purposes	**75**	**122**	43	315
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Current	**4**	**3**	—	29
Non-current	**4**	**—**	3	4
Interest rate derivatives:				
Current	**—**	**61**	—	74
Non-current	**—**	**208**	—	190
Foreign currency derivatives:				
Current	**—**	**36**	—	34
Non-current	**—**	**182**	—	88
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**8**	**490**	3	419
Energy-related derivatives not designated as hedging instruments				
Current	**5**	**3**	8	8
Non-current	**1**	**—**	1	2
Total derivatives not designated as hedging instruments	**6**	**3**	9	10
Gross amounts recognized	**89**	**615**	55	744
Gross amounts offset[a]	**(44)**	**(61)**	(23)	(85)
Net amounts recognized in the Balance Sheets[b]	**$ 45**	**$ 554**	$ 32	$ 659
Alabama Power				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Current	**$ 11**	**$ 30**	$ 6	$ 69
Non-current	**15**	**12**	9	41
Total derivatives designated as hedging instruments for regulatory purposes	**26**	**42**	15	110
Gross amounts offset	**(19)**	**(19)**	(10)	(10)

Net amounts recognized in the Balance Sheets	**$ 7**	**$ 23**	$ 5	$ 100
Georgia Power				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Current	**$ 6**	**$ 32**	$ 2	$ 82
Non-current	**13**	**9**	10	42
Total derivatives designated as hedging instruments for regulatory purposes	**19**	**41**	12	124
Energy-related derivatives not designated as hedging instruments				
Current	**—**	**1**	—	—
Non-current	—	—	1	—
Total derivatives not designated as hedging instruments	**—**	**1**	1	—
Gross amounts recognized	**19**	**42**	13	124
Gross amounts offset	**(15)**	**(15)**	(11)	(11)
Net amounts recognized in the Balance Sheets	**$ 4**	**$ 27**	$ 2	$ 113
Mississippi Power				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Current	**$ 5**	**$ 15**	$ 3	$ 27
Non-current	**14**	**19**	12	34
Total derivatives designated as hedging instruments for regulatory purposes	**19**	**34**	15	61
Gross amounts offset	**(17)**	**(17)**	(14)	(14)
Net amounts recognized in the Balance Sheets	**$ 2**	**$ 17**	$ 1	$ 47
Southern Power				
Derivatives designated as hedging instruments in cash flow hedges				
Energy-related derivatives:				
Current	**$ 1**	**$ —**	$ —	$ 5
Non-current	**3**	**—**	3	—
Foreign currency derivatives:				
Current	**—**	**11**	—	11
Non-current	**—**	**40**	—	11
Total derivatives designated as hedging instruments in cash flow hedges	**4**	**51**	3	27
Net amounts recognized in the Balance Sheets	**$ 4**	**$ 51**	$ 3	$ 27
Southern Company Gas				
Energy-related derivatives designated as hedging instruments for regulatory purposes				
Current	**$ 11**	**$ 5**	$ 1	$ 20
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Current	**3**	**3**	—	24
Non-current	**1**	**—**	—	4
Interest rate derivatives:				
Current	**—**	**17**	—	20
Non-current	—	**67**	—	59
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**4**	**87**	—	107
Energy-related derivatives not designated as hedging instruments				
Current	**5**	**2**	7	8
Non-current	**1**	**—**	1	2
Total derivatives not designated as hedging instruments	**6**	**2**	8	10
Gross amounts recognized	**21**	**94**	9	137
Gross amounts offset[a]	**7**	**(10)**	12	(50)
Net amounts recognized in the Balance Sheets[b]	**$ 28**	**$ 84**	$ 21	$ 87

(a) Gross amounts offset includes cash collateral held on deposit in broker margin accounts of $17 million and $62 million at December 31, 2024 and 2023, respectively.

(b) Net amounts of derivative instruments outstanding exclude immaterial premium and intrinsic value associated with weather derivatives for all periods presented.

At December 31, 2024 and 2023, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized in the Balance Sheets

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
At December 31, 2024:					
Energy-related derivatives:					
Other regulatory assets, current	**$ (61)**	**$ (23)**	**$ (26)**	**$ (11)**	**$ (1)**
Other regulatory assets, deferred	**(5)**	**—**	**—**	**(5)**	**—**
Other regulatory liabilities, current	**8**	**4**	**—**	**—**	**4**
Other regulatory liabilities, deferred	**8**	**3**	**4**	**1**	**—**
Total energy-related derivative gains (losses)	**$ (50)**	**$ (16)**	**$ (22)**	**$ (15)**	**$ 3**
At December 31, 2023:					
Energy-related derivatives:					
Other regulatory assets, current	$ (180)	$ (67)	$ (80)	$ (25)	$ (8)
Other regulatory assets, deferred	(87)	(32)	(33)	(22)	—
Other regulatory liabilities, current	9	4	—	1	4
Other regulatory liabilities, deferred	1	—	1	—	—
Total energy-related derivative gains (losses)	$ (257)	$ (95)	$ (112)	$ (46)	$ (4)

For the years ended December 31, 2024, 2023, and 2022, the pre-tax effects of cash flow and fair value hedge accounting on AOCI for the applicable Registrants were as follows:

Gain (Loss) From Derivatives Recognized in OCI	2024	2023	2022
		(in millions)	
Southern Company			
Cash flow hedges:			
Energy-related derivatives	**$ (7)**	$ (81)	$ 3
Interest rate derivatives	**23**	(12)	46
Foreign currency derivatives	**(40)**	14	(105)
Fair value hedges(*):			
Foreign currency derivatives	**16**	21	(24)
Total	**$ (8)**	$ (58)	$ (80)
Georgia Power			
Cash flow hedges:			
Interest rate derivatives	**$ 24**	$ (2)	$ 31
Mississippi Power			
Cash flow hedges:			
Interest rate derivatives	**$ 7**	$ —	$ —
Southern Power			
Cash flow hedges:			
Energy-related derivatives	**$ (1)**	$ (18)	$ (15)
Foreign currency derivatives	**(40)**	14	(105)
Total	**$ (41)**	$ (4)	$ (120)
Southern Company Gas			
Cash flow hedges:			
Energy-related derivatives	**$ (6)**	$ (63)	$ 18
Interest rate derivatives	**(5)**	—	—
Total	**$ (11)**	$ (63)	$ 18

(*) Represents amounts excluded from the assessment of effectiveness for which the difference between changes in fair value and periodic amortization is recorded in OCI.

The pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on AOCI were immaterial for Alabama Power for the years ended December 31, 2023 and 2022.

The pre-tax effects of cash flow and fair value hedge accounting on income for the years ended December 31, 2024, 2023, and 2022 were as follows:

Statements of Income Location	Derivative Category	Gain (Loss) 2024	2023	2022
			(in millions)	
Southern Company				
Cost of natural gas	Energy-related cash flow hedges	**$ (40)**	$ (44)	$ 37
Other operations and maintenance	Energy-related cash flow hedges	**(2)**	(2)	—
Depreciation and amortization	Energy-related cash flow hedges	**(6)**	(23)	(5)
Interest expense, net of amounts capitalized	Interest rate cash flow hedges	**(16)**	(35)	(25)
	Foreign currency cash flow hedges	**(12)**	(11)	(19)
	Interest rate fair value hedges	**(4)**	37	(291)
Other income (expense), net	Foreign currency cash flow hedges	**(33)**	19	(83)
	Foreign currency fair value hedges	**2**	69	(106)
	Amount excluded from effectiveness testing recognized in earnings	**(16)**	(21)	24
Southern Power				
Depreciation and amortization	Energy-related cash flow hedges	**$ (6)**	$ (23)	$ (5)
Interest expense, net of amounts capitalized	Foreign currency cash flow hedges	**(12)**	(11)	(19)
Other income (expense), net	Foreign currency cash flow hedges	**(33)**	19	(83)
Southern Company Gas				
Cost of natural gas	Energy-related cash flow hedges	**$ (40)**	$ (44)	$ 37
Other operations and maintenance	Energy-related cash flow hedges	**(2)**	(2)	—
Interest expense, net of amounts capitalized	Interest rate cash flow hedges	**(1)**	(19)	(4)
	Interest rate fair value hedges	**(5)**	6	(86)

The pre-tax effects of cash flow hedge accounting on income for interest rate derivatives were immaterial for the traditional electric operating companies for all years presented.

At December 31, 2024 and 2023, the following amounts were recorded on the balance sheets related to cumulative basis adjustments for fair value hedges:

Balance Sheet Location of Hedged Items	Carrying Amount of the Hedged Item		Cumulative Amount of Fair Value Hedging Adjustment included in Carrying Amount of the Hedged Item	
	At December 31, 2024	At December 31, 2023	At December 31, 2024	At December 31, 2023
	(in millions)		*(in millions)*	
Southern Company				
Long-term debt	**$ (2,936)**	$ (3,024)	**$ 242**	$ 235
Southern Company Gas				
Long-term debt	**$ (422)**	$ (427)	**$ 75**	$ 70

The pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income of Southern Company and Southern Company Gas for the years ended December 31, 2024, 2023, and 2022 were as follows:

Derivatives in Non-Designated Hedging Relationships	Statements of Income Location	Gain (Loss) 2024	2023	2022
			(in millions)	
Energy-related derivatives	Natural gas revenues(*)	**$ —**	$ —	$ (11)
	Cost of natural gas	**94**	59	(65)
Total derivatives in non-designated hedging relationships		**$ 94**	$ 59	$ (76)

(*) Excludes the impact of weather derivatives recorded in natural gas revenues of $12 million, $15 million, and $(7) million for 2024, 2023 and 2022, respectively, as they are accounted for based on intrinsic value rather than fair value.

The pre-tax effects of energy-related derivatives not designated as hedging instruments were immaterial for all other Registrants for all years presented.

Contingent Features

The Registrants do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain Southern Company subsidiaries. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. At December 31, 2024, the Registrants had no collateral posted with derivative counterparties to satisfy these arrangements.

For Southern Company, the fair value of foreign currency derivative liabilities and interest rate derivative liabilities with contingent features, and the maximum potential collateral requirements arising from the credit-risk-related contingent features at a rating below BBB- and/or Baa3, was $72 million at December 31, 2024. For Southern Power, the fair value of foreign currency derivative liabilities with contingent features, and the maximum potential collateral requirements arising from the credit-risk-related contingent features at a rating below BBB- and/or Baa3, was $24 million at December 31, 2024. For the traditional electric operating companies and Southern Power, energy-related derivative liabilities with contingent features and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were immaterial at December 31, 2024. The maximum potential collateral requirements arising from the credit-risk-related contingent features for the traditional electric operating companies and Southern Power include certain agreements that could require collateral in the event that one or more Southern Company power pool participants has a credit rating change to below investment grade.

Alabama Power and Southern Power maintain accounts with certain regional transmission organizations to facilitate financial derivative transactions, and they may be required to post collateral based on the value of the positions in these accounts and the associated margin requirements. At December 31, 2024, cash collateral posted in these accounts was immaterial for Alabama Power and Southern Power. Southern Company Gas maintains accounts with brokers or the clearing houses of certain exchanges to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, Southern Company Gas may be required to deposit cash into these accounts. At December 31, 2024, cash collateral held on deposit in broker margin accounts was $17 million.

The Registrants are exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Registrants generally enter into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's, S&P, or Fitch or with counterparties who have posted collateral to cover potential credit exposure. The Registrants have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate their exposure to counterparty credit risk.

Southern Company Gas uses established credit policies to determine and monitor the creditworthiness of counterparties, including requirements to post collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. Prior to entering a physical transaction, Southern Company Gas assigns its counterparties

an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

Southern Company Gas utilizes netting agreements whenever possible to mitigate exposure to counterparty credit risk. Netting agreements enable Southern Company Gas to net certain assets and liabilities by counterparty across product lines and against cash collateral, provided the netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, counterparties are settled net, they are recorded on a gross basis on the balance sheet as energy marketing receivables and energy marketing payables.

The Registrants do not anticipate a material adverse effect on their respective financial statements as a result of counterparty nonperformance.

15. ACQUISITIONS AND DISPOSITIONS

Alabama Power

In 2022, Alabama Power completed its acquisition of the Calhoun Generating Station, which was accounted for as an asset acquisition. The total purchase price was $179 million, of which $171 million was related to net assets recorded within property, plant, and equipment on the balance sheet and reflected in property additions within the investing section of the statement of cash flows. The remainder primarily related to fossil fuel stock and materials and supplies. See Note 2 under "Alabama Power – Rate CNP New Plant" for additional information.

On October 24, 2024, Alabama Power entered into an agreement to acquire all of the equity interests in Tenaska Alabama Partners, L.P., which owns and operates the Lindsay Hill Generating Station. See Note 2 under "Alabama Power – Petition for Certificate of Convenience and Necessity" for additional information.

Mississippi Power

On November 8, 2024, Mississippi Power entered into an agreement with FP&L to acquire FP&L's 50% ownership interest in Plant Daniel Units 1 and 2. See Note 2 under "Mississippi Power – Plant Daniel" for additional information.

Southern Power

Southern Power's acquisition-related costs for the projects discussed under "Asset Acquisitions" and "Construction Projects" were not material for any of the years presented.

Asset Acquisitions

During 2023, Southern Power acquired the Millers Branch and South Cheyenne projects, as discussed further under "Construction Projects" below, with an aggregate purchase price of $193 million. There were no asset acquisitions during 2024 and 2022.

Construction Projects

During 2024, Southern Power completed construction of and placed in service the 150-MW South Cheyenne solar facility. In addition, Southern Power continued construction of the 200-MW first phase and began construction of the 180-MW second phase

and the 132-MW third phase of the Millers Branch solar facility. At December 31, 2024, the total cost of construction incurred for the Millers Branch project was $292 million, which is primarily included in CWIP.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Actual/Projected COD	PPA Contract Period
Projects Under Construction at December 31, 2024					
Millers Branch					
Phase I	Solar	200	Haskell County, TX	Fourth quarter 2025	20 years
Phase II	Solar	180	Haskell County, TX	Second quarter 2026	15 years
Phase III	Solar	132	Haskell County, TX	Fourth quarter 2026	15 years
Projects Completed During 2024					
South Cheyenne	Solar	150	Laramie County, WY	April 2024	20 years
Projects Completed During 2022					
Garland Solar Storage[a]	Battery energy storage	88	Kern County, CA	September 2021 through February 2022[b]	20 years
Tranquillity Solar Storage[a]	Battery energy storage	72	Fresno County, CA	November 2021 through March 2022[c]	20 years

(a) Southern Power consolidates each project's operating results in its financial statements and the tax equity partner and two other partners each own a noncontrolling interest. See Note 9 under "Lessor" for additional information.

(b) The facility has a total capacity of 88 MWs, of which 73 MWs were placed in service in 2021 and 15 MWs were placed in service in 2022.

(c) The facility has a total capacity of 72 MWs, of which 32 MWs were placed in service in 2021 and 40 MWs were placed in service in 2022.

Development Projects

In November 2024, Southern Power committed to a development project to repower 200 MWs of the 299-MW Kay Wind facility located in Kay County, Oklahoma. The output of the project is contracted under an amended 20-year PPA with commercial operation projected to occur in the third quarter 2026.

Southern Company Gas

In September 2022, certain affiliates of Southern Company Gas entered into agreements to sell two natural gas storage facilities located in California and Texas for an aggregate purchase price of $186 million, plus working capital and certain other adjustments. The sale of the Texas facility was completed in November 2022 and the sale of the California facility was completed in September 2023. Both sales resulted in an immaterial loss. Completion of the sale of the Texas facility was subject to release of a Southern Company Gas parent guarantee, which was executed in October 2022 and, as a result, Southern Company Gas recorded pre-tax impairment charges totaling approximately $131 million ($99 million after tax) in the fourth quarter 2022.

Neither of these dispositions, both individually and combined, represented a strategic shift in operations for Southern Company Gas that has, or is expected to have, a major effect on its operations and financial results; therefore, none of the assets related to the sales were classified as discontinued operations for the applicable periods presented.

16. SEGMENT AND RELATED INFORMATION

The Registrants adopted ASU 2023-07 and applied the guidance retrospectively effective for the fiscal year beginning January 1, 2024. See Note 1 under "Recently Adopted Accounting Standards" for additional information.

The CODM at Southern Company, the traditional electric operating companies, and Southern Company Gas is the chairman, president, and chief executive officer of such Registrant. Southern Power's CODM consists of the chairman and chief executive officer and the president. The CODMs assess segment performance using net income that is reflected on the Registrants' respective statements of income as net income attributable to the registrant, net income after dividends on preferred stock, or net income, as applicable. The CODMs use net income in the annual budget and forecasting process and consider budget versus actual results on a monthly basis when making decisions about the allocation of resources. Unless noted below, the CODMs do not utilize segment asset information.

Southern Company

Southern Company's reportable business segments are the sale of electricity by the traditional electric operating companies, the sale of electricity in the competitive wholesale market by Southern Power, and the sale of natural gas and other complementary products and services by Southern Company Gas. While the traditional electric operating companies represent three separate operating segments, they are vertically integrated utilities providing electric service to retail customers, as well as wholesale customers, in the Southeast and have been aggregated into one reportable segment. Revenues from sales by Southern Power to the traditional electric operating companies were $371 million, $537 million, and $875 million in 2024, 2023, and 2022, respectively. Revenues from sales of natural gas from Southern Company Gas to the traditional electric operating companies and Southern Power were immaterial for all periods presented. The "All Other" column includes the Southern Company parent entity, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments

include providing distributed energy and resilience solutions and deploying microgrids for commercial, industrial, governmental, and utility customers, as well as investments in telecommunications. All other inter-segment revenues are not material.

Southern Company's CODM utilizes segment net income, including variances to budget and forecasts, to assess performance and is not provided with segment expense information. To achieve the consolidated net income goal, Southern Company's CODM sets net income expectations for each operating segment, which is expected to monitor its expenses in order to achieve its assigned net income target. Therefore, Southern Company has no reportable significant segment expenses.

Financial data for business segments and products and services for the years ended December 31, 2024, 2023, and 2022 was as follows:

	Electric Utilities								
	Traditional Electric Operating Companies	Southern Power	Eliminations	Total	Southern Company Gas	Total Reportable Segments	All Other	Eliminations	Consolidated
					(in millions)				
2024									
Operating revenues	**$ 19,977**	**$ 2,014**	**$ (388)**	**$ 21,603**	**$ 4,456**	**$ 26,059**	**$ 843**	**$ (178)**	**$ 26,724**
Other segment items[a][b][c][d]	**10,057**	**1,060**	**(388)**	**10,729**	**2,613**	**13,342**	**802**	**(149)**	**13,995**
Depreciation and amortization[e]	**3,512**	**522**	**—**	**4,034**	**650**	**4,684**	**71**	**—**	**4,755**
Earnings from equity method investments	**8**	**—**	**—**	**8**	**146**	**154**	**(17)**	**2**	**139**
Interest expense	**1,255**	**117**	**—**	**1,372**	**341**	**1,713**	**1,030**	**—**	**2,743**
Income taxes (benefit)	**1,016**	**(13)**	**—**	**1,003**	**258**	**1,261**	**(292)**	**—**	**969**
Segment net income (loss)[b][c][d][e][f]	**$ 4,145**	**$ 328**	**$ —**	**$ 4,473**	**$ 740**	**$ 5,213**	**$ (785)**	**$ (27)**	**$ 4,401**
Goodwill	**$ —**	**$ 2**	**$ —**	**$ 2**	**$ 5,015**	**$ 5,017**	**$ 144**	**$ —**	**$ 5,161**
Total assets	**105,577**	**12,653**	**(1,025)**	**117,205**	**26,177**	**143,382**	**2,371**	**(573)**	**145,180**
2023									
Operating revenues	$ 18,358	$ 2,189	$ (549)	$ 19,998	$ 4,702	$ 24,700	$ 718	$ (165)	$ 25,253
Other segment items[a][c][g][h]	9,643	1,187	(549)	10,281	3,124	13,405	699	(150)	13,954
Depreciation and amortization	3,361	504	—	3,865	582	4,447	78	—	4,525
Earnings from equity method investments	(1)	—	—	(1)	140	139	5	—	144
Interest expense	1,145	129	—	1,274	310	1,584	879	(17)	2,446
Income taxes (benefit)	571	12	—	583	211	794	(298)	—	496
Segment net income (loss)[c][f][g][h]	$ 3,637	$ 357	$ —	$ 3,994	$ 615	$ 4,609	$ (635)	$ 2	$ 3,976
Goodwill	$ —	$ 2	$ —	$ 2	$ 5,015	$ 5,017	$ 144	$ —	$ 5,161
Total assets	100,429	12,761	(545)	112,645	25,083	137,728	2,446	(843)	139,331
2022									
Operating revenues	$ 20,408	$ 3,369	$ (904)	$ 22,873	$ 5,962	$ 28,835	$ 593	$ (149)	$ 29,279
Other segment items[a][c][i][j]	12,820	2,341	(904)	14,257	4,536	18,793	771	(138)	19,426
Depreciation and amortization	2,513	516	—	3,029	559	3,588	75	—	3,663
Earnings from equity method investments	—	—	—	—	148	148	3	—	151
Interest expense	929	138	—	1,067	263	1,330	694	(2)	2,022
Income taxes (benefit)	828	20	—	848	180	1,028	(233)	—	795
Segment net income (loss)[c][f][i][j]	$ 3,318	$ 354	$ —	$ 3,672	$ 572	$ 4,244	$ (711)	$ (9)	$ 3,524
Goodwill	$ —	$ 2	$ —	$ 2	$ 5,015	$ 5,017	$ 144	$ —	$ 5,161
Total assets	95,861	13,081	(659)	108,283	24,621	132,904	2,665	(678)	134,891

(a) Primarily consists of fuel, purchased power, cost of natural gas, cost of other sales, other operations and maintenance, taxes other than income taxes, charges (credits) to income for estimated probable losses, losses (gains) on asset dispositions, impairment charges, AFUDC equity, non-service cost-related retirement benefits income, and net income (loss) attributable to noncontrolling interests.

(b) For the traditional electric operating companies, includes a pre-tax impairment loss at Alabama Power of $36 million ($27 million after tax) related to Alabama Power discontinuing the development of a multi-use commercial facility. See Note 1 under "Impairment of Long-Lived Assets" for additional information.

(c) For the traditional electric operating companies, includes pre-tax charges (credits) to income at Georgia Power for the estimated probable loss associated with the construction and completion of Plant Vogtle Units 3 and 4 of $(21) million ($(16) million after tax) in 2024, $(68) million ($(50) million after tax) in 2023, and $183 million ($137 million after tax) in 2022. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

(d) For the traditional electric operating companies, includes a pre-tax gain at Georgia power of approximately $114 million ($84 million after tax) related to the sale of transmission line assets under the integrated transmission system agreement. See Note 2 under "Georgia Power – Transmission Asset Sales" for additional information.

(e) For Southern Power, includes pre-tax accelerated depreciation of $9 million ($7 million after tax) related to the commitment to repower 200 MWs of the Kay Wind facility. See Note 15 under "Southern Power – Development Projects" for additional information.

(f) Attributable to Southern Company.

(g) For Southern Power, includes an $18 million pre-tax loss recovery ($9 million after tax and partnership allocations) related to an arbitration award and a $16 million pre-tax gain ($12 million after tax) on the sale of spare parts. See Note 3 under "General Litigation Matters – Southern Power" for additional information.

(h) For Southern Company Gas, includes pre-tax charges totaling approximately $96 million ($72 million after tax) associated with the disallowance of certain capital investments at Nicor Gas. See Note 2 under "Southern Company Gas" for additional information.

(i) For Southern Company Gas, includes pre-tax impairment charges totaling approximately $131 million ($99 million after tax) related to the sale of natural gas storage facilities. See Note 15 under "Southern Company Gas" for additional information.

(j) For the "All Other" column, includes a $119 million goodwill impairment loss (pre-tax and after tax) at PowerSecure. See Note 1 under "Goodwill and Other Intangible Assets" for additional information.

Products and Services

	Electric Utilities' Revenues			
Year	**Retail**	**Wholesale**	**Other**	**Total**
		(in millions)		
2024	**$ 17,790**	**$ 2,431**	**$ 1,382**	**$ 21,603**
2023	16,343	2,467	1,188	19,998
2022	18,197	3,641	1,035	22,873

Southern Company Gas' Revenues

Year	Gas Distribution Operations	Gas Marketing Services	All Other	Total
		(in millions)		
2024	**$ 3,899**	**$ 516**	**$ 41**	**$ 4,456**
2023	4,090	548	64	4,702
2022	5,240	638	84	5,962

Traditional Electric Operating Companies

Each of the traditional electric operating companies' single reportable business segment is the sale of electricity. Revenues from products and services of the traditional electric operating companies are segregated into retail, wholesale, and other as reflected on their statements of income.

Alabama Power and Georgia Power have identified utility operations and maintenance expenses as significant segment expenses provided to their CODMs. Utility operations and maintenance expenses is calculated as other operations and maintenance, as reflected on the statements of income, less expenses from unregulated products and services, losses (gains) on asset dispositions, impairment charges, and amortization of cloud software. Alabama Power's utility operations and maintenance expenses are disaggregated into expenses related to Rate RSE and Rate CNP Compliance, which are not applicable to Georgia Power. See Note 2 under "Alabama Power" for additional information.

Financial data for Alabama Power's and Georgia Power's significant segment expenses and other segment information for the years ended December 31, 2024, 2023, and 2022 was as follows:

	2024	2023	2022
		(in millions)	
Alabama Power			
Operating revenues	**$ 7,554**	$ 7,050	$ 7,817
Utility operations and maintenance			
Rate RSE expenses	**1,480**	1,421	1,645
Rate CNP Compliance expenses	**279**	254	237
Total utility operations and maintenance	**1,759**	1,675	1,882
Other segment items[a][b]	**2,125**	2,098	2,915
Depreciation and amortization	**1,459**	1,401	875
Interest expense	**448**	425	382
Income taxes	**360**	81	423
Segment net income[b]	**$ 1,403**	$ 1,370	$ 1,340
Capital expenditures	**$ 2,114**	$ 2,159	$ 2,206
Georgia Power			
Operating revenues	**$ 11,331**	$ 10,118	$ 11,584
Utility operations and maintenance	**2,210**	1,901	2,237
Other segment items[a][c][d]	**3,476**	3,382	5,249
Depreciation and amortization	**1,774**	1,681	1,430
Interest expense	**725**	626	485
Income taxes	**603**	448	370
Segment net income[c][d]	**$ 2,543**	$ 2,080	$ 1,813
Capital expenditures	**$ 5,355**	$ 5,394	$ 4,219

(a) Primarily consists of fuel, purchased power, expenses from unregulated products and services, losses (gains) on asset dispositions, impairment charges, amortization of cloud software, taxes other than income taxes, charges (credits) to income for estimated probable losses, AFUDC equity, and non-service cost-related retirement benefits income. Also includes earnings from equity method investments, which were immaterial for all periods presented.

(b) For 2024, includes a pre-tax impairment loss of $36 million ($27 million after tax) related to Alabama Power discontinuing the development of a multi-use commercial facility. See Note 1 under "Impairment of Long-Lived Assets" for additional information.

(c) Includes pre-tax charges (credits) to income for the estimated probable loss associated with the construction and completion of Plant Vogtle Units 3 and 4 of $(21) million ($(16) million after tax) in 2024, $(68) million ($(50) million after tax) in 2023, and $183 million ($137 million after tax) in 2022. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

(d) For 2024, includes a pre-tax gain of approximately $114 million ($84 million after tax) related to the sale of transmission line assets under the integrated transmission system agreement. See Note 2 under "Georgia Power – Transmission Asset Sales" for additional information.

Mississippi Power's CODM utilizes segment expense information in the form of variances to budget to assess performance; therefore, Mississippi Power has no reportable significant segment expenses. Mississippi Power's segment information for revenues, depreciation and amortization, interest expense, and income taxes is reflected on its statements of income. Mississippi Power's earnings from equity method investments are included in other income (expense), net on its statements of income and were immaterial for all periods presented. Other segment items primarily consist of fuel and purchased power, other operations and maintenance, taxes other than income taxes, and non-service cost-related retirement benefits income and totaled $0.9 billion, $1.0 billion, and $1.3 billion for the years ended December 31, 2024, 2023, and 2022, respectively.

Southern Power

Southern Power's single reportable business segment is the sale of electricity in the competitive wholesale market. Substantially all of Southern Power's revenues from products and services are reflected as wholesale on its consolidated statements of income. Southern Power's CODM utilizes segment expense information in the form of variances to budget to assess performance; therefore, Southern Power has no reportable significant segment expenses. Southern Power's segment information for revenues,

depreciation and amortization, interest expense, and income taxes (benefit) is reflected on its consolidated statements of income. Southern Power had no earnings from equity method investments for any period presented. Other segment items primarily consist of fuel, purchased power, other operations and maintenance, taxes other than income taxes, losses (gains) on asset dispositions, and net income (loss) attributable to noncontrolling interests and totaled $1.1 billion, $1.2 billion, and $2.3 billion for the years ended December 31, 2024, 2023, and 2022, respectively.

Southern Company Gas

Southern Company Gas manages its business through three reportable segments – gas distribution operations, gas pipeline investments, and gas marketing services. The non-reportable segments are combined and presented as all other. See Note 15 under "Southern Company Gas" for additional information on the disposition activities described herein.

The gas distribution operations segment is the largest component of Southern Company Gas' business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in four states.

The gas pipeline investments segment consists of joint ventures in natural gas pipeline investments including a 50% interest in SNG and a 50% joint ownership interest in the Dalton Pipeline. These natural gas pipelines enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. See Notes 5 and 7 for additional information.

The gas marketing services segment provides natural gas marketing to end-use customers primarily in Georgia and Illinois through SouthStar.

The "All Other" column includes segments and subsidiaries that fall below the quantitative threshold for separate disclosure, including storage and fuels operations. The "All Other" column included a natural gas storage facility in Texas through its sale in November 2022 and a natural gas storage facility in California through its sale in September 2023.

Southern Company Gas' CODM utilizes segment expense information in the form of variances to budget to assess performance; therefore, Southern Company Gas has no reportable significant segment expenses.

Financial data for business segments for the years ended December 31, 2024, 2023, and 2022 was as follows:

	Gas Distribution Operations	Gas Pipeline Investments	Gas Marketing Services	Total Reportable Segments	All Other	Eliminations	Consolidated
				(in millions)			
2024							
Operating revenues	**$ 3,899**	**$ 32**	**$ 516**	**$ 4,447**	**$ 23**	**$ (14)**	**$ 4,456**
Other segment items[a]	**2,236**	**6**	**356**	**2,598**	**29**	**(14)**	**2,613**
Depreciation and amortization	**630**	**5**	**14**	**649**	**1**	**—**	**650**
Earnings from equity method investments	**—**	**146**	**—**	**146**	**—**	**—**	**146**
Interest expense	**311**	**35**	**3**	**349**	**(8)**	**—**	**341**
Income taxes	**172**	**31**	**41**	**244**	**14**	**—**	**258**
Segment net income (loss)	**$ 550**	**$ 101**	**$ 102**	**$ 753**	**$ (13)**	**$ —**	**$ 740**
Total assets	**$ 24,067**	**$ 1,573**	**$ 1,696**	**$ 27,336**	**$ 10,047**	**$ (11,206)**	**$ 26,177**
2023							
Operating revenues	$ 4,105	$ 32	$ 548	$ 4,685	$ 36	$ (19)	$ 4,702
Other segment items[a][b]	2,702	5	402	3,109	34	(19)	3,124
Depreciation and amortization	561	5	15	581	1	—	582
Earnings from equity method investments	—	140	—	140	—	—	140
Interest expense	275	32	3	310	—	—	310
Income taxes	126	32	37	195	16	—	211
Segment net income (loss)[b]	$ 441	$ 98	$ 91	$ 630	$ (15)	$ —	$ 615
Total assets	$ 22,906	$ 1,534	$ 1,615	$ 26,055	$ 9,675	$ (10,647)	$ 25,083
2022							
Operating revenues	$ 5,267	$ 32	$ 638	$ 5,937	$ 55	$ (30)	$ 5,962
Other segment items[a][c]	3,907	6	488	4,401	165	(30)	4,536
Depreciation and amortization	516	5	16	537	22	—	559
Earnings from equity method investments	—	148	—	148	—	—	148
Interest expense	229	27	3	259	4	—	263
Income taxes (benefit)	145	35	37	217	(37)	—	180
Segment net income (loss)[c]	$ 470	$ 107	$ 94	$ 671	$ (99)	$ —	$ 572
Total assets	$ 22,040	$ 1,577	$ 1,616	$ 25,233	$ 8,943	$ (9,555)	$ 24,621

(a) Primarily consists of cost of natural gas, other operations and maintenance, taxes other than income taxes, impairment charges, estimated loss on regulatory disallowance, AFUDC equity, and non-service cost-related retirement benefits income.

(b) For gas distribution operations, includes pre-tax charges totaling approximately $96 million ($72 million after tax) associated with the disallowance of certain capital investments at Nicor Gas. See Note 2 under "Southern Company Gas" for additional information.

(c) For the "All Other" column, includes pre-tax impairment charges totaling approximately $131 million ($99 million after tax) related to the sale of natural gas storage facilities. See Note 15 under "Southern Company Gas" for additional information.

3. CONTINGENCIES, COMMITMENTS, AND GUARANTEES

General Litigation Matters

The Registrants are involved in various matters being litigated and regulatory matters. The ultimate outcome of such pending or potential litigation or regulatory matters against each Registrant and any subsidiaries cannot be determined at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on such Registrant's financial statements.

The Registrants intend to dispute the allegations raised in and vigorously defend against the pending legal challenges discussed below; however, the ultimate outcome of each of these matters cannot be determined at this time.

Southern Company and Mississippi Power

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper County energy facility through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2. In 2016, additional DOE grants in the amount of $137 million were awarded to the Kemper County energy facility. In 2018, Mississippi Power filed with the DOE its request for property closeout certification under the contract related to the $387 million of total grants received. In 2020, Mississippi Power and Southern Company executed an agreement with the DOE completing Mississippi Power's request,

which enabled Mississippi Power to proceed with full dismantlement of the abandoned gasifier-related assets and site restoration activities. In connection with the DOE closeout discussions, in 2019, the Civil Division of the Department of Justice informed Southern Company and Mississippi Power of a civil investigation related to the DOE grants. In August 2023, the U.S. District Court for the Northern District of Georgia unsealed a civil action in which defendants Southern Company, SCS, and Mississippi Power are alleged to have violated certain provisions of the False Claims Act by fraudulently inducing the DOE to disburse funds pursuant to the grants. The federal government declined to intervene in the action. In October 2023, the plaintiff, a former SCS employee, filed an amended complaint, again alleging certain violations of the False Claims Act. The plaintiff seeks to recover all damages incurred personally and on behalf of the federal government caused by the defendants' alleged violations, as well as treble damages and attorneys' fees, among other relief. On February 2, 2024, the defendants moved to dismiss the amended complaint. On August 28, 2024, the court granted the defendants' motion in part and denied it in part, dismissing the plaintiff's False Claims Act count along with its accompanying treble damages and attorneys' fees but allowing the employment retaliation claim to proceed. The plaintiff requested interlocutory appeal of the court's decision on October 4, 2024. On October 14, 2024, the defendants asserted counterclaims for conversion and misappropriation of trade secrets. On November 20, 2024, the defendants filed a motion for judgment on the pleadings on the plaintiff's employment retaliation claim. On December 23, 2024, the plaintiff filed a motion to dismiss the defendants' counterclaims. An adverse outcome could have a material impact on Southern Company's and Mississippi Power's financial statements.

Alabama Power

In September 2022, Mobile Baykeeper filed a citizen suit in the U.S. District Court for the Southern District of Alabama alleging that Alabama Power's plan to close the Plant Barry surface impoundment utilizing a closure-in-place methodology violates the Resource Conservation and Recovery Act (RCRA) and regulations governing CCR. Among other relief requested, Mobile Baykeeper

sought a declaratory judgment that the RCRA and regulations governing CCR were being violated, preliminary and injunctive relief to prevent implementation of Alabama Power's closure plan, and the development of a closure plan that satisfies regulations governing CCR requirements. In December 2022, Alabama Power filed a motion to dismiss the case. On January 4, 2024, the lawsuit was dismissed without prejudice by the U.S. District Court judge. On February 1, 2024, the plaintiff filed a motion to reconsider, which was denied by the U.S. District Court judge on July 22, 2024. On August 20, 2024, the plaintiff filed a notice of appeal in the U.S. Court of Appeals for the Eleventh Circuit challenging the denial of the motion to reconsider the order of dismissal.

In January 2023, the EPA issued a Notice of Potential Violations (NOPV) associated with Alabama Power's plan to close the Plant Barry surface impoundment. On September 26, 2024, Alabama Power reached a settlement with the EPA resolving two of the three allegations in the NOPV related to the groundwater monitoring system and the emergency action plan at the Plant Barry surface impoundment. The settlement did not resolve the EPA's allegation relating to Alabama Power's plan to close the Plant Barry surface impoundment. Alabama Power has affirmed to the EPA its position that it is in compliance with CCR requirements.

These matters could have a material impact on Alabama Power's and Southern Company's financial statements, including ARO estimates and cash flows. See Note 6 for a discussion of Alabama Power's ARO liabilities.

Georgia Power

In July 2020, a group of individual plaintiffs filed a complaint, which was amended in December 2022, in the Superior Court of Fulton County, Georgia against Georgia Power alleging that the construction and operation of Plant Scherer has impacted groundwater and air, resulting in alleged personal injuries and property damage. The plaintiffs sought an unspecified amount of monetary damages including punitive damages, a medical monitoring fund, and injunctive relief. In December 2022, the Superior Court of Fulton County, Georgia granted Georgia Power's motion to transfer the case to the Superior Court of Monroe County, Georgia. In May 2023, the Superior Court of Monroe County, Georgia denied Georgia Power's motion to dismiss the case for lack of subject matter jurisdiction. In July 2023, the Superior Court of Monroe County, Georgia denied the remaining motions to dismiss certain claims and plaintiffs that Georgia Power filed at the outset of the case. On March 11, 2024, Georgia Power filed a motion to dismiss certain claims. On March 14, 2024, Georgia Power filed motions for summary judgment. In May 2024, Georgia Power filed additional motions for summary judgment. In August 2024, the court denied certain motions for summary judgment, while granting other motions for summary judgment, eliminating some claims from the first one-plaintiff trial.

In October 2021, February 2022, and January 2023, a total of eight additional complaints were filed in the Superior Court of Monroe County, Georgia against Georgia Power alleging that releases from Plant Scherer have impacted groundwater and air, resulting in alleged personal injuries and property damage. The plaintiffs sought an unspecified amount of monetary damages including punitive damages. After Georgia Power removed these cases to the U.S. District Court for the Middle District of Georgia, the plaintiffs voluntarily dismissed their complaints without prejudice in November 2022 and January 2023. In May 2023, the plaintiffs in the cases originally filed in October 2021, February 2022, and January 2023 refiled their eight complaints in the Superior Court of Monroe County, Georgia. Also in May 2023, a new complaint was filed in the Superior Court of Monroe County, Georgia against Georgia Power alleging that the construction and operation of Plant Scherer have impacted groundwater and air, resulting in alleged personal injuries. The plaintiff sought an unspecified amount of monetary damages, including punitive damages. Also in May 2023, Georgia Power removed all of these cases to the U.S. District Court for the Middle District of Georgia. The plaintiffs requested the court remand the cases back to the Superior Court of Monroe County, Georgia.

On November 18, 2024, the parties reached an agreement to resolve all pending lawsuits in the Superior Court of Fulton County, Georgia and the Superior Court of Monroe County, Georgia. On November 22, 2024, the Superior Court of Monroe County, Georgia entered an order granting Georgia Power's motions for summary judgment, finding there is no evidence that Georgia Power's operations negatively impacted drinking water wells or caused personal injury or property damage. On November 25, 2024, the plaintiffs voluntarily dismissed with prejudice all remaining claims in the litigation. The settlement amount did not have a material impact on Georgia Power's financial statements. These matters are now concluded.

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional electric operating companies and the natural gas distribution utilities conduct studies to determine the extent of any required cleanup and have recognized the estimated costs to clean up known impacted sites in the financial statements. A liability for environmental remediation costs is recognized only when a loss is determined to be probable and reasonably estimable and is reduced as expenditures are incurred. The traditional electric operating companies and the natural gas distribution utilities in Illinois and Georgia have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental remediation costs through regulatory mechanisms. Any difference between the liabilities accrued and costs recovered through rates is deferred as a regulatory asset or liability. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies.

Georgia Power has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected. For 2024, 2023, and 2022, Georgia Power recovered approximately $5 million, $5 million, and $12 million, respectively, through the ECCR tariff for environmental remediation.

Southern Company Gas is subject to environmental remediation liabilities associated with former manufactured gas plant sites. Southern Company Gas' accrued environmental remediation liability at December 31, 2024 and 2023 was based on the estimated cost of environmental investigation and remediation associated with these sites.

At December 31, 2024 and 2023, the environmental remediation liability and the balance of under recovered environmental remediation costs were reflected in the balance sheets of Southern Company, Georgia Power, and Southern Company Gas as

shown in the table below. Alabama Power and Mississippi Power did not have environmental remediation liabilities at December 31, 2024 or 2023.

	Southern Company	Georgia Power	Southern Company Gas
		(in millions)	
December 31, 2024:			
Environmental remediation liability:			
Other current liabilities	**$ 37**	**$ 13**	**$ 24**
Accrued environmental remediation	**198**	**—**	**198**
Under recovered environmental remediation costs:			
Other regulatory assets, current	**$ 37**	**$ 5**	**$ 32**
Other regulatory assets, deferred	**212**	**11**	**201**
December 31, 2023:			
Environmental remediation liability:			
Other current liabilities	$ 44	$ 14	$ 30
Accrued environmental remediation	192	—	192
Under recovered environmental remediation costs:			
Other regulatory assets, current	$ 45	$ 5	$ 40
Other regulatory assets, deferred	210	15	195

The ultimate outcome of these matters cannot be determined at this time; however, as a result of the regulatory treatment for environmental remediation expenses described above, the final disposition of these matters is not expected to have a material impact on the financial statements of the applicable Registrants.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that required the DOE to take title to and dispose of spent nuclear fuel generated at Plants Farley, Hatch, and Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, Alabama Power and Georgia Power filed their third round of lawsuits against the U.S. government in the Court of Federal Claims, seeking damages for the costs of continuing to store spent nuclear fuel at Plants Farley, Hatch, and Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. In 2019, the Court of Federal Claims granted Alabama Power's and Georgia Power's motion for summary judgment on damages not disputed by the U.S. government, awarding those undisputed damages to Alabama Power and Georgia Power.

In 2017, Alabama Power and Georgia Power filed their fourth round of lawsuits against the U.S. government in the Court of Federal Claims, seeking damages for the costs of continuing to store spent nuclear fuel at Plants Farley, Hatch, and Vogtle Units 1 and 2 for the period from January 1, 2015 through December 31, 2017. In 2020, Alabama Power and Georgia Power filed amended complaints in those fourth-round lawsuits adding damages incurred from January 1, 2018 to December 31, 2019 to the claim period.

On June 7, 2024, and August 15, 2024, the Court of Federal Claims entered final judgments on the remaining damages in the third and fourth round of lawsuits, respectively, awarding Alabama Power a total of approximately $100 million and Georgia Power a total of approximately $121 million (based on its ownership interests), which represent claims for the period from January 1, 2011 through December 31, 2019. This represents recovery on all claims that Alabama Power and Georgia Power have filed against the U.S. government to date.

On December 3, 2024, the Alabama PSC directed Alabama Power to return the award, which was reflected as a regulatory liability at December 31, 2024, to customers through bill credits during the months of January, February, and March 2025. During the third quarter 2024, Georgia Power credited the award to accounts where the original costs were charged, which reduced rate base, fuel, and cost of service for the benefit of customers, as previously authorized by the Georgia PSC. As a result of this regulatory treatment, there will be no material impact on Southern Company's, Alabama Power's, or Georgia Power's net income.

Damages will continue to accumulate until the issue is resolved, the U.S. government disposes of Alabama Power's and Georgia Power's spent nuclear fuel pursuant to its contractual obligations, or alternative storage is otherwise provided. However, Alabama Power and Georgia Power expect to credit any future recoveries for the benefit of customers in accordance with direction from their respective PSC; therefore, no material impact on Southern Company's, Alabama Power's, or Georgia Power's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

Nuclear Insurance

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $16.3 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 $500 million by American Nuclear Insurers (ANI), 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. A company could be assessed up to $166 million per incident for each licensed reactor it operates but not more than an aggregate of $25 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $332 million and $473 million, respectively, per incident, but not more than an aggregate of $49 million and $71 million, respectively, to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than November 1, 2028. See Note 5 under "Joint Ownership Agreements" for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses and policies providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted. Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations, and have each elected a 12-week deductible waiting period for each nuclear plant.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for Alabama Power and Georgia Power as of December 31, 2024 under the NEIL policies would be $60 million and $80 million, respectively.

Claims resulting from terrorist acts and cyber events are covered under both the ANI and NEIL policies (subject to normal policy limits). The maximum aggregate that NEIL will pay for all claims resulting from terrorist acts and cyber events in any 12-month period is $3.2 billion each, plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident.

Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the applicable company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's, Alabama Power's, and Georgia Power's financial condition, cash flows, and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

Other Matters

Alabama Power

In April 2019, Bellsouth Telecommunications d/b/a AT&T Alabama (AT&T) filed a complaint against Alabama Power with the FCC alleging that the pole rental rate AT&T is required to pay pursuant to the parties' joint use agreement is unjust and unreasonable under federal law. The complaint sought a new rate and refunds of alleged overpayments since 2013. In August 2019, the FCC stayed the case in favor of arbitration, which AT&T did not pursue. On December 31, 2024, Alabama Power and AT&T reached a settlement that resolved several disputes between the parties, including the outstanding FCC complaint. The terms of the settlement are not expected to have a material impact on Alabama Power's or Southern Company's financial statements. The joint use agreement remains in effect.

Mississippi Power

In 2022, 2023, and 2024, Mississippi Power recorded charges to income associated with abandonment and related closure costs and ongoing period costs, net of salvage proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. These charges, including related tax impacts, totaled $15 million pre-tax ($12 million after tax) in 2022, $17 million pre-tax ($12 million after tax) in 2023, and $12 million pre-tax ($9 million after tax) in 2024. The pre-tax charges are included in other operations and maintenance expenses on the statements of income.

Dismantlement of the abandoned gasifier-related assets and site restoration activities are expected to be completed by the end of 2025. Additional pre-tax period costs associated with dismantlement and site restoration activities, including related costs for compliance and safety, ARO accretion, and property taxes, net of salvage, are estimated to total approximately $15 million.

See "General Litigation Matters – Southern Company and Mississippi Power" herein for information regarding litigation associated with the Kemper County energy facility.

Commitments

To supply a portion of the fuel requirements of the Southern Company system's electric generating plants, the Southern Company system has entered into various long-term commitments not recognized on the balance sheets for the procurement and delivery of fossil fuel and, for Alabama Power and Georgia Power, nuclear fuel. The majority of the Registrants' fuel expense for the periods presented was purchased under long-term commitments. Each Registrant expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

Georgia Power has commitments, in the form of capacity purchases, regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any

capacity is available. Portions of the capacity payments made to MEAG Power for its Plant Vogtle Units 1 and 2 investment relate to costs in excess of Georgia Power's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity is included in purchased power in Southern Company's statements of income and in purchased power, non-affiliates in Georgia Power's statements of income. Georgia Power's capacity payments related to this commitment totaled $4 million, $3 million, and $4 million in 2024, 2023, and

2022, respectively. At December 31, 2024, Georgia Power's estimated long-term obligations related to this commitment totaled $35 million, consisting of $3 million for 2025, $2 million annually for 2026 through 2029, and $24 million thereafter.

See Note 9 for information regarding PPAs accounted for as leases.

Guarantees

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with each of the traditional electric operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Alabama Power has guaranteed a $100 million principal amount long-term bank loan SEGCO entered into in 2018 and subsequently extended and amended. Georgia Power has agreed to reimburse Alabama Power for the portion of such obligation corresponding to Georgia Power's proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. At December 31, 2024, the capitalization of SEGCO consisted of $56 million of equity and $80 million of long-term debt that matures in November 2025, on which the annual interest requirement is derived from a variable rate index. SEGCO had no short-term debt outstanding at December 31, 2024. See Note 7 under "SEGCO" for additional information.

As discussed in Note 9, Alabama Power and Georgia Power have entered into certain residual value guarantees related to railcar leases, with Georgia Power's railcar leases terminating in June 2024.

17. SUBSEQUENT EVENTS

None.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)	T Comp In
1	Balance of Account 219 at Beginning of Preceding Year					(12,479,411)		(12,479,411)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income					4,588,082		4,588,082		
3	Preceding Quarter/Year to Date Changes in Fair Value					(1,586,134)		(1,586,134)		
4	Total (lines 2 and 3)					3,001,948		3,001,948	2,079,614,443	2,08
5	Balance of Account 219 at End of Preceding Quarter/Year					(9,477,463)		(9,477,463)		
6	Balance of Account 219 at Beginning of Current Year					(9,477,463)		(9,477,463)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income					3,820,231		3,820,231		
8	Current Quarter/Year to Date Changes in Fair Value					18,302,910		18,302,910		
9	Total (lines 7 and 8)					22,123,141		22,123,141	2,542,698,229	2,56
10	Balance of Account 219 at End of Current Quarter/Year				(a) 0	12,645,678		12,645,678		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedOtherComprehensiveIncomeLossOtherAdjustmentsToComprehensiveIncomeLossBalance

See Schedules 232 and 278 for gas and electric fair value hedges

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)	54,595,118,331	54,595,118,331					
4	Property Under Capital Leases	2,317,536,655	2,317,536,655					
5	Plant Purchased or Sold							
6	Completed Construction not Classified							
7	Experimental Plant Unclassified							
8	Total (3 thru 7)	56,912,654,986	56,912,654,986					
9	Leased to Others							
10	Held for Future Use	105,649,857	105,649,857					
11	Construction Work in Progress	3,211,575,035	3,211,575,035					
12	Acquisition Adjustments	28,251,085	28,251,085					
13	Total Utility Plant (8 thru 12)	60,258,130,963	60,258,130,963					
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	14,597,089,190	14,597,089,190					
15	Net Utility Plant (13 less 14)	45,661,041,773	45,661,041,773					
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION							
17	In Service:							
18	Depreciation	13,947,110,432	13,947,110,432					
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	621,799,468	621,799,468					
22	Total in Service (18 thru 21)	14,568,909,900	14,568,909,900					
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	28,179,290	28,179,290					
33	Total Accum Prov (equals 14) (22,26,30,31,32)	14,597,089,190	14,597,089,190					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	47,240,135	98,383,171		[b]118,201,533	27,421,773
3	Nuclear Materials	47,197,254	87,745,263		[c]100,175,785	34,766,732
4	Allowance for Funds Used during Construction	22,451,424	9,039,112		[d]29,738,104	1,752,432
5	(Other Overhead Construction Costs, provide details in footnote)	6,679,521	11,163,081		[e]16,331,414	1,511,188
6	SUBTOTAL (Total 2 thru 5)	123,568,334			264,446,836	65,452,125
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)	246,947,277	264,446,836		[f]241,651,999	269,742,114
9	In Reactor (120.3)	566,785,247	241,651,999		[g]136,478,977	671,958,269
10	SUBTOTAL (Total 8 & 9)	813,732,524				941,700,383
11	Spent Nuclear Fuel (120.4)	45,418,490	136,478,977		[h]96,819,165	85,078,302
12	Nuclear Fuel Under Capital Leases (120.6)					
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	377,554,986		[a](103,903,929)		481,458,915
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	605,164,362				610,771,895
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: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedProvisionForAmortizationOfNuclearFuelAssembliesAmortization

Line 13 - Column D Consists of:		
Amortization Expense	$	(203,718,701)
Original Cost of Assets Retired		99,814,772
Transfer of Retired Fuel Assemblies to 120.4		—
Total	$	(103,903,929)

(b) Concept: FabricationCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	118,201,533
Reactor Account - 120.3		—
Total	$	118,201,533

(c) Concept: NuclearMaterialsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	100,175,785
Reactor Account - 120.3		—
Total	$	100,175,785

(d) Concept: AllowanceForFundsConstructionNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	29,738,104
Reactor Account - 120.3		—
Total	$	29,738,104

(e) Concept: OtherOverheadConstructionCostsNuclearFuelInProcessOfRefinementConversionEnrichmentAndFabricationOtherReductions

Net Transfers To:		
Stock Account - 120.2	$	16,368,385
Reactor Account - 120.3		(36,971)
Total	$	16,331,414

(f) Concept: NuclearFuelMaterialsAndAssembliesInStockOtherReductions

Transfers of:		
Completed Assemblies to Reactor Account 120.3	$	241,651,999

(g) Concept: NuclearFuelAssembliesInReactorOtherReductions

Transfers of:		
Completed Burn Assembly to Spent Fuel 120.4	$	136,478,977

(h) Concept: SpentNuclearFuelOtherReductions

Transfers of:		
Retired Assemblies to 120.5	$	96,819,165
Transfer of Retired Fuel Assemblies to 120.3		—
Total	$	96,819,165

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	45,130					45,130
3	(302) Franchise and Consents	40,900,343	8,652,729	98,167			49,454,905
4	(303) Miscellaneous Intangible Plant	785,299,316	67,251,554	13,241,260			839,309,610
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	826,244,789	75,904,283	13,339,427			888,809,645
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant						
8	(310) Land and Land Rights	48,129,537	264,988	30,338			48,364,187
9	(311) Structures and Improvements	783,897,023	2,603,447	719,735			785,780,735
10	(312) Boiler Plant Equipment	5,480,597,923	141,221,856	39,590,095			5,582,229,684
11	(313) Engines and Engine-Driven Generators						
12	(314) Turbogenerator Units	541,132,646	7,264,714	955,593			547,441,767
13	(315) Accessory Electric Equipment	190,677,393	9,090,477	1,876,498			197,891,372
14	(316) Misc. Power Plant Equipment	45,501,697	4,044,929	893,538			48,653,088

15	(317) Asset Retirement Costs for Steam Production	746,987,675	57,371,915	137,631,308			666,728,282
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	7,836,923,894	221,862,326	181,697,105			7,877,089,115
17	B. Nuclear Production Plant						
18	(320) Land and Land Rights	1,087,894		921			1,086,973
19	(321) Structures and Improvements	5,953,546,013	(1,197,582,382)	9,077,095			4,746,886,536
20	(322) Reactor Plant Equipment	2,205,730,786	2,734,052,780	58,383,141			4,881,400,425
21	(323) Turbogenerator Units	625,516,909	674,684,901	11,404,192			1,288,797,618
22	(324) Accessory Electric Equipment	544,503,503	810,559,410	17,842,215			1,337,220,698
23	(325) Misc. Power Plant Equipment	232,664,471	352,882,307	12,784,480			572,762,298
24	(326) Asset Retirement Costs for Nuclear Production	386,662,713	(271,264,556)	1,729,767			113,668,390
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	9,949,712,289	3,103,332,460	111,221,811			12,941,822,938
26	C. Hydraulic Production Plant						
27	(330) Land and Land Rights	35,677,652	(6,930)	17,149			35,653,573
28	(331) Structures and Improvements	139,211,660	2,046,881	154,041			141,104,500
29	(332) Reservoirs, Dams, and Waterways	341,098,201	51,591,828	5,214,447			387,475,582
30	(333) Water Wheels, Turbines, and Generators	320,378,476	10,222,820	2,242,020			328,359,276
31	(334) Accessory Electric Equipment	66,972,040	15,336,038	641,356			81,666,722
32	(335) Misc. Power Plant Equipment	40,300,242	7,356,595	289,839			47,366,998
33	(336) Roads, Railroads, and Bridges	8,463,638	(367)				8,463,271
34	(337) Asset Retirement Costs for Hydraulic Production	6,493,611	(553,908)	(161,576)			6,101,279
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	958,595,520	85,992,957	8,397,276			1,036,191,201
36	D. Other Production Plant						
37	(340) Land and Land Rights	37,003,665	2,465,494				39,469,159
38	(341) Structures and Improvements	1,891,719,344	680,905,065	227,865,178			2,344,759,231

39	(342) Fuel Holders, Products, and Accessories	89,703,803	10,095,593	327,207			99,472,189
40	(343) Prime Movers	1,748,519,984	306,421,169	125,765,250			1,929,175,903
41	(344) Generators	1,258,358,801	(88,998,262)	8,553,120			1,160,807,419
42	(345) Accessory Electric Equipment	160,405,119	109,463,475	244,662			269,623,932
43	(346) Misc. Power Plant Equipment	43,480,395	96,204,312	20,086			139,664,621
44	(347) Asset Retirement Costs for Other Production	49,988,035	2,004,838	(304,724)			52,297,597
44.1	(348) Energy Storage Equipment - Production						
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	5,279,179,146	1,118,561,684	362,470,779			6,035,270,051
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	24,024,410,849	4,605,653,710	677,126,398			27,890,373,305
47	3. Transmission Plant						
48	(350) Land and Land Rights	472,838,135	53,512,793	16,541,353			509,809,575
48.1	(351) Energy Storage Equipment - Transmission						
49	(352) Structures and Improvements	338,441,971	78,206,937	2,065,295			414,583,613
50	(353) Station Equipment	3,226,458,153	228,671,113	3,792,544			3,451,336,722
51	(354) Towers and Fixtures	1,317,647,820	145,958,794	31,595,955			1,432,010,659
52	(355) Poles and Fixtures	846,775,814	65,360,127	109,584,514			802,551,427
53	(356) Overhead Conductors and Devices	2,058,567,171	192,070,478	199,847,618			2,050,790,031
54	(357) Underground Conduit	11,851,603	407,446	593,867			11,665,182
55	(358) Underground Conductors and Devices	25,710,527	803,617	431,817			26,082,327
56	(359) Roads and Trails	17,119,968	4,845,285	660,371			21,304,882
57	(359.1) Asset Retirement Costs for Transmission Plant	(848,994)	(11,608)	(107,274)			(753,328)
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	8,314,562,168	769,824,982	365,006,060			8,719,381,090
59	4. Distribution Plant						
60	(360) Land and Land Rights	302,613,076	55,398,624	(1,467,684)			359,479,384
61	(361) Structures and Improvements	352,148,646	37,475,002	1,775,650			387,847,998
62	(362) Station Equipment	2,234,269,882	325,066,163	4,946,840			2,554,389,205

63	(363) Energy Storage Equipment – Distribution						
64	(364) Poles, Towers, and Fixtures	1,551,410,696	244,338,896	7,086,156			1,788,663,436
65	(365) Overhead Conductors and Devices	1,923,501,575	250,787,649	15,367,020			2,158,922,204
66	(366) Underground Conduit	651,942,870	51,388,728	1,994,367			701,337,231
67	(367) Underground Conductors and Devices	3,134,937,941	255,725,174	10,221,356			3,380,441,759
68	(368) Line Transformers	2,156,395,036	234,778,027	108,214,538			2,282,958,525
69	(369) Services	1,285,382,851	54,580,020	1,783,231			1,338,179,640
70	(370) Meters	575,979,889	44,259,646	11,872,861			608,366,674
71	(371) Installations on Customer Premises	29,211,086	16,381,922	46,447			45,546,561
72	(372) Leased Property on Customer Premises	798,128		467,833			330,295
73	(373) Street Lighting and Signal Systems	1,149,781,805	131,346,964	31,854,062			1,249,274,707
74	(374) Asset Retirement Costs for Distribution Plant	452,201	(343,712)	(13,549)			122,038
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	15,348,825,682	1,701,183,103	194,149,128			16,855,859,657
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	35,953,655	105,563	44,449			36,014,769

87	(390) Structures and Improvements	874,294,655	48,144,288	4,124,338			918,314,605
88	(391) Office Furniture and Equipment	126,425,214	14,467,094	7,472,210			133,420,098
89	(392) Transportation Equipment	431,920,083	63,190,391	4,609,273			490,501,201
90	(393) Stores Equipment	15,968,622	3,913,161	369,770			19,512,013
91	(394) Tools, Shop and Garage Equipment	90,366,177	31,740,263	5,126,557			116,979,883
92	(395) Laboratory Equipment	71,029,010	5,874,140	5,219,527			71,683,623
93	(396) Power Operated Equipment	50,553,243	3,056,854	601,848			53,008,249
94	(397) Communication Equipment	577,702,258	106,406,156	31,140,021			652,968,393
95	(398) Miscellaneous Equipment	59,656,378	11,436,284	1,988,103			69,104,559
96	SUBTOTAL (Enter Total of lines 86 thru 95)	2,333,869,295	288,334,194	60,696,096			2,561,507,393
97	(399) Other Tangible Property						
98	(399.1) Asset Retirement Costs for General Plant	(5,327,821)	176,423	(1,875,294)			(3,276,104)
99	TOTAL General Plant (Enter Total of lines 96, 97, and 98)	2,328,541,474	288,510,617	58,820,802			2,558,231,289
100	TOTAL (Accounts 101 and 106)	50,842,584,962	7,365,172,412	1,295,102,388			56,912,654,986
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)	50,842,584,962	7,365,172,412	1,295,102,388			56,912,654,986 [(a)]

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantInService

Plant-in-service balances include the following lease balances:

		Plant in Service
Capital Leases:		
Other Production	$	318,035,103
General		89,570,682
	$	407,605,785
Operating Leases:		
Steam Production	$	51,844,253
Other Production		1,799,437,344
Nuclear Production		1,058,445
General		57,590,828
	$	1,909,930,870

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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						
2						
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42						
43						
44						
45						
46						
47	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Dawson Crossing-S Dahlonega 500kv T/L	12/01/2008	12/31/2040	10,543,832
3	New Hampstead Substation	06/30/2009	12/31/2028	53,836
4	S Dahlonega-Clermont Jct 500kv T/L	09/30/2009	12/31/2040	28,188,653
5	S Dahlonega-Clermont Jct 230kv T/L	09/30/2009	12/31/2040	17,268,413
6	Bethabara-E. Walton 230kv T/L Site	03/31/2011	12/31/2040	3,708,308
7	Piedmont Substation Site	03/31/2011	12/31/2040	12,933,362
8	Boyd Ave Substation Site	08/31/2012	12/31/2040	1,334,192
9	Stewart County	09/01/2012	12/31/2030 [a]	22,615,987
10	McDonough-East Point 230 KV	09/01/2014	12/31/2040	89,188
11	Utoy Springs Substation Site	09/01/2014	12/31/2040	594,185
12	Wallace Dam - Klondike 500 KV	09/01/2014	12/31/2031	3,628,989
13	South Hall - Winder T/L	09/01/2014	12/31/2035	883,035
14	Medical Arts Substation Site	02/01/2017	12/31/2026	1,236,066
15	Savannah Portside International- Old River Road Substation Site	08/01/2018	12/31/2040	30,266
16	Northwest Region Operating HQ Site	10/01/2019	12/31/2026	529,886
17	Granite City Substation Site	08/01/2024	12/31/2026	246,785
18	East Canon Substation Site	09/01/2024	12/31/2026	195,753
19	Spring Valley Road Substation Site	12/01/2024	12/31/2026	560,079
20	Balus Creek 115 kV Substation Site	12/01/2024	12/31/2026	1,009,042
21	Other Property:			
22				
23				
24				
25				
26				
27				

28				
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46				
47	TOTAL			105,649,857

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ElectricPlantPropertyClassifiedAsHeldForFutureUseExpectedUseInServiceDate

The earliest date this is expected to be in service is 12/31/2030.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Plant Bowen - Clean Air Compliance	86,239,658
2	Plant Scherer - Land & Water Projects	1,434,793
3	Plant Scherer - Outage Projects	1,159,412
4	Plant Hatch - Controls	1,744,306
5	Plant Hatch - Electrical	1,612,803
6	Plant Hatch - Miscellaneous Additions	6,608,976
7	Plant Vogtle 1&2 - Controls	4,039,034
8	Plant Vogtle 1&2 - Miscellaneous Additions	8,457,215
9	Chattahoochee Hydro Miscellaneous Additions	113,121,462
10	North Georgia Hydro Miscellaneous Additions	42,340,531
11	Plant Mcintosh - Miscellaneous Additions	1,453,986
12	Plant McDonough - Miscellaneous Additions	3,250,945
13	Plant Wilson CT - Miscellaneous Additions	3,162,302
14	Distribution New Business	8,791,066
15	Outdoor Lighting Projects	1,822,470
16	Miscellaenous Transmission Line Replacements	16,101,212
17	Miscellaneous Transmission Line Additions & Improvements	2,470,085
18	Miscellaneous Transmission Substation Additions & Improvements	6,279,410
19	Miscellaneous Distribution Substation Additions & Improvements	3,406,463
20	Grid Investment	32,901,155
21	Substation Reliability Improvements	40,253,997
22	Distribution Projects Contribution In Aid Of Construction Offset	19,918,213
23	Protective Relay Modernization Project	1,252,846
24	Distribution Network Improvements - Miscellaneous	20,395,708
25	ROW Services Perfection	2,940,709
26	Enterprise Solutions System Upgrades	10,450,538
27	Power Delivery Software Upgrades	2,908,671
28	Fiber Optics Spurs Construction	102,581,599
29	Communications Improvements	1,247,833

30	Generation Software Upgrades	4,711,539
31	Customer Service System (CSS) Upgrades	8,419,362
32	Building Additions & Improvements	2,813,868
33	Capital Maintenance / Asset Management	248,062,664
34	Commitments	34,896,497
35	Facility	195,815,216
36	Intangible	12,144,291
37	Load Related System Improvements	54,059,177
38	Miscellaneous	212,452,272
39	New Business	310,265,814
40	Other General Plant	17,545,845
41	Software Purchases and Upgrades	204,101,912
42	Technology	98,180,917
43	Plant Bowen - Air	3,230,164
44	Outage	40,968,138
45	Plant Scherer - Water	9,428,440
46	Reliability	127,965,089
47	System Flow Projects	21,021,514
48	System Operations - Study Driven - Generation Changes	154,892,507
49	Unassigned	9,957,066
50	Misc GSU	7,232,689
51	Plant Scherer - Air	5,141,819
52	Grid Improvement	88,415,297
53	Products and Services	2,972,049
54	Fiber	18,052,898
55	Unregulated ODL	8,020,594
56	Plant Scherer - Land	1,003,786
57	Fleet	3,463,444
58	McIntosh CT - GPC - Air	5,823,849
59	Yates CT	646,783,074
60	GPC Battery Storage	117,843,046
61	Scherer Oracle Topside	(6,691,471)
62	Miscellaneous Minor Projects (Less Than $1 Million)	(5,765,729)
43	Total	3,211,575,035

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	13,400,830,050	13,400,830,050		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,509,442,181	1,509,442,181		
4	(403.1) Depreciation Expense for Asset Retirement Costs	27,077,698	27,077,698		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	25,879,351	25,879,351		
7	Other Clearing Accounts	124,310,549	124,310,549		
8	Other Accounts (Specify, details in footnote):				
9.1	Other Accounts (Specify, details in footnote):	167,818,021	[a]167,818,021		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,854,527,800	1,854,527,800		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(1,281,762,960)	[b](1,281,762,960)		
13	Cost of Removal	(406,430,931)	(406,430,931)		
14	Salvage (Credit)	272,669,043	272,669,043		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	(1,415,524,848)	(1,415,524,848)		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17.1	Other Debit or Cr. Items (Describe, details in footnote):	107,277,430	[c]107,277,430		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	13,947,110,432	[d]13,947,110,432		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,356,731,776	3,356,731,776		

21	Nuclear Production	3,106,428,324	3,106,428,324		
22	Hydraulic Production-Conventional	(2,364,235,265)	(2,364,235,265)		
23	Hydraulic Production-Pumped Storage	2,862,664,297	2,862,664,297		
24	Other Production	954,357,117	954,357,117		
25	Transmission	1,348,803,730	1,348,803,730		
26	Distribution	3,730,943,494	3,730,943,494		
27	Regional Transmission and Market Operation				
28	General	951,416,959	951,416,959		
29	TOTAL (Enter Total of lines 20 thru 28)	13,947,110,432	(e)13,947,110,432		

FOOTNOTE DATA

(a) Concept: OtherAccounts

Reflects provision of Account 108 related to capital/operating leases not recorded to Account 403

		Depreciation Expense
Capital Leases:		
Other Production	$	20,663,979
General		—
	$	20,663,979
Operating Leases:		
Steam Production	$	9,395,242
Nuclear Production		175,078
Other Production		128,410,181
General		9,173,540
	$	147,154,041

(b) Concept: BookCostOfRetiredPlant

Variance between Schedule Page 204-207 Line No.:100 Column: d and Schedule Page 219 Line No.: 12 Column: c is due to the exclusion of intangible plant retirements on Page 219 for $13,339,428.

(c) Concept: OtherAdjustmentsToAccumulatedDepreciation

Reflects retired plant net book values moved to FERC 182 Deferred Debits and gain/loss resulting from retirements of operating leases.

(d) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Accumulated depreciation balances include the following lease balances:

		Accumulated Depreciation
Capital Leases:		
Other Production	$	(110,677,467)
General		(69,793,614)
	$	(180,471,081)
Operating Leases:		
Steam Production	$	(22,982,487)
Nuclear Production		(210,113)
Other Production		(525,831,422)
General		(30,249,699)
	$	(579,273,721)

(e) Concept: AccumulatedProvisionForDepreciationOfElectricUtilityPlant

Accumulated depreciation balances include the following lease balances:

		Accumulated Depreciation
Capital Leases:		
Other Production	$	(110,677,467)
General		(69,793,614)
	$	(180,471,081)
Operating Leases:		
Steam Production	$	(22,982,487)
Nuclear Production		(210,113)
Other Production		(525,831,422)
General		(30,249,699)
	$	(579,273,721)

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Southern Electric Generating Co.							
2	Common Stock - 90,000 shares	02/11/1959		9,000,000			9,000,000	
3	Common Stock - 45,000 shares	01/25/1960		4,500,000			4,500,000	
4	Common Stock - 23,000 shares	08/28/1969		2,300,000			2,300,000	
5	Common Stock - 6,000 shares	09/23/1968		600,000			600,000	
6	Equity in Undistributed Earnings			18,331,404	4,825,860	(11,772,141)	11,385,123	
7	Piedmont Forrest Corporation							
8	Common Stock - 100,000 shares	11/17/1977		100,000			100,000	
9	Other Paid-in-Capital							
10	Equity in Undistributed Earnings			17,567,804	1,005,500	(1,043,339)	17,529,965	
11	Advances from Parent (open account)							
42	Total Cost of Account 123.1 $ 16,500,000		Total	52,399,208	5,831,360	(12,815,480)	45,415,088	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)	468,132,742	371,907,472	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	4,961,210	5,459,044	Electric
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)	465,007,514	507,644,780	Electric
8	Transmission Plant (Estimated)	174,985,475	182,499,094	Electric
9	Distribution Plant (Estimated)	237,675,943	272,278,039	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	(a)5,332,731	(b)5,493,553	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	883,001,663	967,915,466	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	263,239	113,505	Electric
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	12,811	(9,110)	
17				
18				
19				
20	TOTAL Materials and Supplies	1,356,371,665	1,345,386,377	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to Other:

		12/31/2023
First Aid & Safety	$	1,791,764
Automotive		1,898,921
In-transit		1,510,309
Construction materials		131,737
	$	5,332,731

(b) Concept: PlantMaterialsAndOperatingSuppliesOther

Assigned to Other:

		12/31/2024
First Aid & Safety	$	1,582,717
Automotive		2,152,355
In-transit		1,644,205
Construction materials		114,276
	$	5,493,553

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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.	SO2 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	4,436,882	7,223,951									4,436,882	7,223,951
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	387,543										387,543	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	16,017	15,884									16,017	15,884
19	Other:												
20	Allowances Used												

20.1	Allowances Used												
21	Cost of Sales/Transfers:												
22	Adjustment												
23													
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	4,808,408	7,208,067									4,808,408	7,208,067
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	9,066	183									9,066	183
38	Deduct: Returned by EPA	9,066	183									9,066	183
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: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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.	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	312,147										312,147	
2													
3	Acquired During Year:												
4	Issued (Less Withheld Allow)	24,300										24,300	
5	Returned by EPA												
6													
7													
8	Purchases/Transfers:												
9													
10													
11													
12													
13													
14													
15	Total												
16													
17	Relinquished During Year:												
18	Charges to Account 509	13,364										13,364	
19	Other:												
20	Allowances Used												
20.1	Allowances Used												

21	Cost of Sales/Transfers:												
22	Adjustment												
23	Associated Sales – Mississippi Power Company												
24													
25													
26													
27													
28	Total												
29	Balance-End of Year	323,083										323,083	
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: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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						
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19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
20	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						

49	TOTAL					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	(a) None				
20	Total				
21	**Generation Studies**				
22	(b) None				
39	Total				
40	Grand Total				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfStudyPerformed

Southern Company Services receives up-front payments for studies and operating companies do not record any charges to these accounts. Costs are bore at system level. The only time an operating company would have anything to report on page 231 is when the charges exceed the amount collected and the customer does not reimburse Southern Company. Any study completed by an operating company and is under the OATT should be reported by that operating company on page 231.

(b) Concept: DescriptionOfStudyPerformed

Southern Company Services receives up-front payments for studies and operating companies do not record any charges to these accounts. Costs are bore at system level. The only time an operating company would have anything to report on page 231 is when the charges exceed the amount collected and the customer does not reimburse Southern Company. Any study completed by an operating company and is under the OATT should be reported by that operating company on page 231.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	(a) Vacation Pay Accrued	107,491,780	9,369,322	Various	4,930,994	111,930,108
2	(b) Deferred Income Taxes	611,876,281	212,933,188	282,283	183,542,571	641,266,898
3	(c) Retiree Benefit Plans	1,062,458,869	19,282,525	228,407.3	105,590,479	976,150,915
4	(d) Generating Plant Outage Costs	32,649,003	64,827,630	407.3	44,505,982	52,970,651
5	(e) Asset Retirement Obligations	4,487,351,464	468,614,927	254,411	387,691,503	4,568,274,888
6	(f) Gas and Electric Hedges	132,099,838	120,886,144	Various	208,943,062	44,042,920
7	(g) Storm Damage	54,207,894	803,965,865	924	31,419,234	826,754,525
8	(h) COVID-19 Costs	16,803,734		407.3	8,401,867	8,401,867
9	(i) Environmental Remediation	20,153,893	795,121	924	5,052,418	15,896,596
10	(j) Deferred Plant Retirement Costs	846,580,149	1,506,228	407.3	116,604,004	731,482,373
11	(k) Revenue Erosion	1,328,241	840,484	442	1,696,182	472,543
12	(l) Customer Data Usage	151,562	263,291	905	414,853	
13	(m) Software & Cloud Computing	83,802,200	41,616,674	923	9,781,703	115,637,171
14	(n) Energy Efficiency Improvements	27,886		908	5,436	22,450
15	(o) Nuclear Decommissioning	20,554,455	15,760,189	407.3	12,746,126	23,568,518
16	(p) Nuclear Financing	13,655,312	25,047,337	407.3	15,538,558	23,164,091
17	(q) Deferred Plant Depreciation	126,832,363	122,136,638	—		248,969,001
18	(r) NCCR Under-Recovery		9,369,761			9,369,761
44	TOTAL	7,618,024,924	1,917,215,324		1,136,864,972	8,398,375,276

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Earned vacation pay is deferred and recognized only when paid as ordered by the Georgia Public Service Commission (PSC) in Docket No. 3270.

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Plant Vogtle Units 3 and 4 Prudency Stipulation in Docket No. 29849, and as a result of Plant Vogtle Unit 4 being placed in service on April 29, 2024, the unprotected deficient accumulated deferred income taxes associated with the remeasurement of deferred income taxes on the construction work in progress for Plant Vogtle Units 3 and 4 as a result of the Tax Cuts and Jobs Act will be recovered over a period of 10 years starting in May 2024. In accordance with certain provisions of the Inflation Reduction Act, the Company has elected to opt out of normalization requirements on certain federal investment tax credits (ITC) and has amortized the ITC more rapidly than over the asset life. The ITCs that have been amortized more rapidly than over the underlying asset lives will be classified as regulatory assets, FERC 182, and will offset the unamortized ITC balances in FERC account 255, Deferred ITC in accordance with ASC 980 overlay accounting. The amortization of the ITC Normalization Opt-out balances in FERC account 182 will offset the amortization of the unamortized ITC balances from FERC 255 over the asset lives which is currently expected to be 20 years. The remaining deferred income taxes are being amortized over the related remaining property lives in accordance with IRS normalization principles which may range up to 54 years.

	Beginning Balance	Amortized to 411.1	Net DR/CR Adj	Ending Balance
Deferred Income Taxes	$ 466,398,214	$ —	$ 16,000,104	$ 482,398,318
Unprotected DADIT NCCR	$ 145,478,067	$ 3,251,756	$ (13,731,667)	$ 134,998,156
ITC Normalization Opt-out			$ 23,870,425	$ 23,870,425

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Retiree benefit plans are recovered through current rates over the average remaining service period as ordered by the Georgia PSC in Docket No. 4565, which may range up to 14 years.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Nuclear outage costs are deferred and amortized over the respective unit's operating cycle as ordered by the Georgia PSC in Docket No. 4007.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Coal Combustion Residuals (CCR) AROs are recovered through the Environmental Compliance Cost Recovery tariff, with approximately $160 million and $100 million recovered in 2023 and 2024, respectively, and approximately $220 million expected to be recovered in 2025, with the recovery amount for 2026 and future years updated through future rate case proceedings. Effective January 1, 2023, approximately $17 million annually is being recovered for non-CCR AROs in traditional base tariffs through December 31, 2025. Other cost of removal obligations and non-CCR AROs are recovered over the related property lives, which may range up to 54 years.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Realized and unrealized losses arising from marked to market gas and electric hedges are deferred and recovered when settled as ordered by the Georgia PSC in Docket No. 16134. The Company's natural gas hedging program uses an array of derivative instruments within a 36-month time horizon, as ordered by the Georgia PSC in Docket No. 43011.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Effective January 1, 2023, the Company is accruing $31 million annually through December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280, to cover the operations and maintenance costs of damages from major storms to its transmission and distribution facilities, which are recoverable through base rates.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 42516, the Company deferred incremental bad debt and other incremental costs in certain identified cost categories that were incurred as result of the COVID-19 pandemic. At December 31, 2022, the incremental costs deferred totaled approximately $25 million. Effective January 1, 2023, the Company is amortizing these costs over a three-year period ending December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Effective January 1, 2023, the Company is accruing $5 million annually through December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280, to cover the costs of environmental remediation.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC orders in Docket Nos. 34218, 36498, 42310 and 44160, deferred plant retirement costs, including remaining net book values and unusable materials and supplies inventories, are classified as a regulatory asset. The remaining net book values of Plant Branch Units 3 and 4 and Plant Hammond Units 1-4 are being amortized over a period equal to the units' remaining useful lives as approved by the Georgia PSC in Docket Nos. 31958 and 36989, respectively. Effective January 1, 2023, the remaining net book value of Plants Wansley Units 1 and 2 is being amortized over a period equal to the units' remaining useful lives as approved by the Georgia PSC in Docket No. 42516 and the remaining net book value of Plant Wansley CT Unit 5A is being amortized over a three-year period ending December 31, 2025, as ordered by the Georgia PSC in Docket No. 44280. The decision on the timing of the recovery of the unusable materials and supplies inventories will be deferred until a future base rate case.

(k) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 44280, any revenue erosion resulting from the conversion of additional customers to a specific time-of-use rate will be deferred and recovered from customers in 2023 through 2025 through the annual compliance filings.

(l) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 44280, costs associated with investigation and implementation of providing hourly usage information to all metered customers is to be recovered over a three-year period ending December 31, 2025. In the third quarter 2024, recovery of these costs exceeded total expenditures of the program and the excess recovered amount is classified as a regulatory liability, FERC 254, and amortization will be determined by the Georgia PSC in future regulatory proceedings.

(m) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

Effective January 1, 2023, certain implementation costs related to software and cloud computing projects incurred through 2022 were deferred and are being amortized over a five-year period ending December 31, 2027, in accordance with the Georgia PSC order in Docket No. 44280. The recovery of deferred costs incurred since 2022 will be determined by the Georgia PSC in the next base rate case.

(n) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket Nos. 42310 and 42311, the costs of energy efficient upgrades, prepaid by the Company, for participating customers associated with the Income Qualified Tariff Based Energy Efficiency Pilot, or Residential Investment Saving Energy Pilot, are deferred and recovered from those customers over the life of the installed

equipment not to exceed ten years.

(o) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Nuclear Regulatory Commission requirement to satisfy funding assurance for nuclear decommissioning, the Company provided funding to the external nuclear decommissioning trust for Plant Vogtle Unit 3 of $7.6 million in 2022. In 2023, the Company funded $0.8 million, $7.6 million, and $7.8 million related to Plant Vogtle Units 1, 3, and 4, respectively. Effective August 1, 2023, the Company is amortizing $7.6 million annually until the next base rate case, as ordered by the Georgia PSC in Docket No. 43838, for the funding of future costs related to decommissioning Plant Vogtle Unit 3. As ordered by the Georgia PSC in Docket No. 29849, and as a result of Plant Vogtle Unit 4 being placed in service on April 29, 2024, the Company is amortizing $7.8 million annually effective May 1, 2024 until the next base rate case, for the funding of future costs related to decommissioning Plant Vogtle Unit 4. The recovery of the $0.8 million of funding for Plant Vogtle Unit 1 will be determined by the Georgia PSC in the next base rate case.

(p) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 44280 to recover the net book values of Plants Bowen and Scherer through 2034, $40 million and $70 million of the depreciation for Plants Bowen and Scherer, respectively, are being deferred annually to a regulatory asset over the units' remaining useful lives through 2030 and 2028, respectively. The regulatory asset will be amortized beginning at the end of their useful lives through December 31, 2034.

(q) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Plant Vogtle Unit 3 Base Rate Filing Order in Docket No. 43838, financing costs on Plant Vogtle Unit 3 and common facilities capital and construction costs above $2.1 billion and excluded from the Nuclear Construction Cost Recovery Tariff were deferred to a regulatory asset until Plant Vogtle Unit 4 achieved commercial operation. In accordance with the Plant Vogtle Units 3 and 4 Prudency Stipulation in Docket No. 29849, and as a result of Plant Vogtle Unit 4 being placed in service on April 29, 2024, the Company is amortizing these financing costs effective May 1, 2024 over a period of 10 years.

(r) Concept: DescriptionAndPurposeOfOtherRegulatoryAssets

In accordance with the Georgia PSC order in Docket No. 29849, the under-recovered amount associated with the Nuclear Construction Cost Recovery Tariff was deferred to a regulatory asset and the recovery of the under-recovered amount will be determined by the Georgia PSC in the next base rate case.

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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		Balance at End of Year (f)
				Credits Account Charged (d)	Credits Amount (e)	
1	Jobs in Progress - Cost	13,605,045	30,515,918	143	28,092,317	16,028,646
2	Joint Owner Other Deferred Billings	1,681,860	1,161,531	902-926, 143	2,789,094	54,297
3	Funding Collateral	509,356		131	509,356	
4	Progress Payments	71,664,924	306,969,318	107, 120.4, 154	234,522,833	144,111,409
5	Non Current Fuel Cost Recovery	1,210,842,432	905,756,709	440, 442, 444, 446	1,663,137,504	453,461,637
6	[(a)] Cash Surrender Value Insurance (a)	7,019,428	435,612	426.2	2,020,626	5,434,414
7	Disputed Payments	1,221,915	2,238,495	181	3,460,410	
8	Deferred Capitalized Interest on Nuclear Fuel During Construction	38,206,705	785,165	432	15,619,479	23,372,391
9	Miscellaneous Deferred Debits	626,280	923,191	Various	879,776	669,695
10	Other Post-Retirement Benefits and Pension-Associated Co	215,348,421	23,728,669	234		239,077,090
11	[(b)] Credit Line Fees (b)	5,313,835	1,350,487	431	1,267,154	5,397,168
12	[(c)] Transmission Solar Interconnection (c)	9,168,556		555	374,476	8,794,080
13	Pooled Equipment Inventory Operating Fund Deposit	65,196				65,196
14	[(d)] Sales Commissions (d)	4,880,735	29,177,623	416, 912	33,819,379	238,979
15				—		
47	Miscellaneous Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	1,580,154,688				896,705,002

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DescriptionOfMiscellaneousDeferredDebits
The annual adjustment for the Cash Surrender Value Insurance is amortized over a 12-month period.
(b) Concept: DescriptionOfMiscellaneousDeferredDebits
Credit line fees are amortized over the term of the related credit facility.
(c) Concept: DescriptionOfMiscellaneousDeferredDebits
Transmission Solar Interconnection reimbursements are being amortized over 20 or 30 years depending on the terms of the purchase power agreement starting in April 2017.
(d) Concept: DescriptionOfMiscellaneousDeferredDebits
Sales commissions are amortized over the term of the sales contracts which range from 2 to 3 years.

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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		1,347,309,257	1,312,363,857
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,347,309,257	1,312,363,857
9	Gas		
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)		
17.1	Other (Specify)	156,781,694	132,886,450
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,504,090,951	[(a)]1,445,250,307

Notes

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxes

ACCUMULATED DEFERRED INCOME TAXES (ACCOUNT 190)	BALANCE AT BEG OF YEAR	BALANCE AT END OF YEAR
Accrual for Uncollectibles	$ 1,018,960	$ 3,747,816
Accumulated Rate Refund Georgia Public Service Commission	$ 12	$ 1,244
Affirmative Adjustments*	$ 8,478,950	$ —
Capacity Buybacks*	$ —	$ —
Capitalized Purchase Power Agreement Southern Power Co	$ 8,878,525	$ 7,702,895
Deferred Revenues - Electric	$ 981,932	$ (7,938,864)
Demand Side Management Recovery	$ 11,673,980	$ 13,143,149
FAS 133 Mark to Market*	$ 7,776,485	$ 8,453,921
Health Reimbursement Accrual	$ 598,744	$ 584,486
Income Taxes Deferred - Electric (OATT Included)	$ 158,582,525	$ 158,276,089
Income Taxes Deferred - Electric (OATT Excluded)	$ 94,265,490	$ 76,491,728
Protected Gross Up EADIT	$ 530,655,047	$ 492,900,313
Income Taxes Deferred - CWIP Electric	$ (8,376,711)	$ (290,564)
Income Taxes Deferred - Non Electric*	$ (19,793,690)	$ (28,698,853)
Income Taxes Deferred - CWIP Non Electric*	$ (16,158,001)	$ —
Injuries & Damages Reserve	$ 696,625	$ (10,670,864)
Nuclear Construction Cost Recovery Over/Under Recovery	$ —	$ —
Other Comprehensive Income - Hedge Settlement	$ 3,038,900	$ (4,952,159)
Other Basis Differences	$ 77,408,551	$ 78,271,629
Accrued Liabilities - Electric	$ 114,650,508	$ 80,776,983
Accrued Liabilities - Non Electric*	$ 16,445,346	$ 27,374,480
Environmental Remediation (RBA Order)	$ (5,133,539)	$ (3,980,559)
Storm Damage	$ —	$ —
Tax Credit Carry Forward - Electric	$ 363,710,569	$ 387,149,475
Tax Credit Carry Forward - Non Electric*	$ 160,032,604	$ 125,756,902
Unbilled Fuel Revenues	$ 31,714,873	$ 49,330,885
Unprotected Gross Up Deficient EADIT NCCR	$ (37,055,734)	$ (33,803,978)
Unprotected State Gross Up EADIT OATT Included	$ —	$ 19,154,141
Unprotected State Gross Up EADIT OATT Excluded	$ —	$ 6,470,012
Total	$ 1,504,090,951	$ 1,445,250,307
*Other Income and Deductions		
Classification of Totals:		
Federal Income Tax	$ 828,576,722	$ 848,777,309
State Income Tax	$ 675,514,229	$ 596,472,998

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Common Stock (No Par)	20,000,000			9,261,500	398,473,175				
6	Total	20,000,000			9,261,500	398,473,175				
7	Preferred Stock (Account 204)									
8	Cumulative Preferred, Par Value $100 Per Share	5,000,000	100.00							
9	Non-Cumulative, Par Value $25 Per Share	50,000,000	25.00							
10	Non-Cumulative, Par Value $100 Per Share	15,000,000	100.00							
20	Total	70,000,000								

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2025-04-03	Year/Period of Report End of: 2024/ 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.

Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.
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.
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.
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	
3.1	Increases (Decreases) from Sales of Donations Received from Stockholders	
4	Ending Balance Amount	
5	**Reduction in Par or Stated Value of Capital Stock (Account 209)**	
6	Beginning Balance Amount	
7.1	Increases (Decreases) Due to Reductions in Par or Stated Value of Capital Stock	
8	Ending Balance Amount	
9	**Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210)**	
10	Beginning Balance Amount	
11.1	Increases (Decreases) from Gain or Resale or Cancellation of Reacquired Capital Stock	
12	Ending Balance Amount	
13	**Miscellaneous Paid-In Capital (Account 211)**	
14	Beginning Balance Amount	17,914,475,721
15.1	Increases (Decreases) Due to Miscellaneous Paid-In Capital	
15.2	Contributions to capital by parent company	1,780,123,565
15.3	Miscellaneous contributions to capital	4,140,050
16	Ending Balance Amount	19,698,739,336
17	**Other Paid in Capital**	
18	Beginning Balance Amount	
19.1	Increases (Decreases) in Other Paid-In Capital	
20	Ending Balance Amount	
40	Total	19,698,739,336

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 frc 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
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. 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
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, 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 c
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
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 (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)	AMORTIZATIC PERIOD Dat From (j)
1	Bonds (Account 221)									
2	Bartow 2nd Series 2009	—	100,000,000							
3	Subtotal		100,000,000							
4	Reacquired Bonds (Account 222)									
5	Bartow 2nd Series 2009	—	(100,000,000)							
6	Subtotal		(100,000,000)							
7	Advances from Associated Companies (Account 223)									
8										
9										
10										
11	Subtotal									
12	Other Long Term Debt (Account 224)									
13	Series 2007 A - 5.65%	—	(b)250,000,000		1,780,008		856,478	03/13/2007	03/01/2037	04/01/2007
14	Series 2007 D - 6.375%	—	300,000,000					07/17/2007	07/15/2047	07/01/2007

15	Series 2009A - 5.95%	—	500,000,000		2,679,965		1,020,706	02/10/2009	02/01/2039	02/01/2009
16	Series 2010B - 5.4%	—	600,000,000		3,385,341		2,335,496	06/03/2010	06/01/2040	06/01/2010
17	Series 2010C - 4.75%	—	500,000,000		4,533,506		4,820,000	08/31/2010	09/01/2040	08/01/2010
18	Series 2012A - 4.30%	—	1,100,000,000		10,792,848	4,228,165	383,702	03/06/2012	03/15/2042	03/01/2012
19	Series 2013A - 4.3%	—	400,000,000		3,884,160		2,604,020	03/15/2013	03/15/2043	03/01/2013
20	Series 2016A - 3.25%	—	325,000,000		2,337,915		1,222,000	03/08/2016	04/01/2026	03/01/2016
21	Series 2017B - 3.25%	—	400,000,000		2,876,271		452,000	03/03/2017	03/30/2027	03/01/2017
22	Series 2019A - 2.20%	—	400,000,000					09/10/2019	09/15/2024	09/01/2019
23	Series 2019B - 2.65%	—	650,000,000		4,769,103		4,882,500	09/10/2019	09/15/2029	09/01/2019
24	Series 2020B - 3.70%	—	500,000,000		4,707,331		1,630,000	01/10/2020	01/30/2050	01/01/2020
25	Series 2021A - 3.25%	—	750,000,000		7,142,232		727,500	02/26/2021	03/15/2051	02/26/2021
26	Series 2022A - 4.70%	—	700,000,000		5,057,712		2,226,000	05/04/2022	05/15/2032	05/04/2022
27	Series 2022B - 5.125%	—	800,000,000		7,426,647		5,840,000	05/04/2022	05/15/2052	05/04/2022
28	Series 2023A - 4.65%	—	750,000,000		5,085,398		945,000	05/04/2023	05/16/2028	05/04/2023
29	Series 2023B - 4.95%	—	1,000,000,000		7,204,869		1,740,000	05/04/2023	05/17/2033	05/04/2023
30	Series 2023C - Variable	—	700,000,000		1,870,326			11/08/2023	05/08/2025	11/08/2023
31	Series 2024A - 5.004%	—	500,000,000		2,293,172			02/23/2024	02/23/2027	02/23/2024
32	Series 2024B - 5.25%	—	900,000,000		6,602,742		2,889,000	02/23/2024	03/15/2034	02/23/2024
33	Series 2024C - Variable	—	117,087,000		1,499,720			11/13/2024	11/15/2074	11/13/2024
34	Series 2024D - 4.55%	—	600,000,000		3,998,898		1,410,000	12/05/2024	03/15/2030	12/05/2024
35	Heard 1st Series 1996 - Variable	—	3,800,000		281,716			09/01/1996	09/01/2026	09/01/1996
36	Floyd 1st Series 1996 - Variable	—	10,080,000		234,522			09/01/1996	09/01/2026	09/01/1996
37	Burke 1st Series 1996 - Variable	—	46,000,000		1,346,718			09/01/1996	10/01/2032	09/01/1996
38	Monroe 1st Series 1997 - Variable	—	19,600,000		719,734			04/01/1997	04/01/2032	04/01/1997

39	Appling 1st Series 1997 - Variable	—	18,500,000		863,498			09/01/1997	09/01/2029	09/01/1997
40	Heard 1st Series 1997 - Variable	—	33,700,000		800,281			09/01/1997	09/01/2029	09/01/1997
41	Bartow 1st Series 1997 - 1.80%	—	38,000,000		1,827,936			09/01/1997	09/01/2029	09/01/1997
42	Burke 2nd Series 1994 - 2.25%	—	10,000,000		275,986			01/01/1994	10/01/2032	01/01/1994
43	Burke 4th Series 1994 - 2.25%	—	55,000,000		919,195			01/01/1994	10/01/2032	01/01/1994
44	Burke 5th Series 1994 - 2.15%	—	55,000,000		1,599,536			01/01/1994	10/01/2032	01/01/1994
45	Burke 9th Series 1994 - 2.25%	—	20,000,000		425,804			01/01/1994	10/01/2032	01/01/1994
46	Monroe 1st Series 1995 - 2.25%	—	45,000,000		1,543,239			07/01/1995	07/01/2025	07/01/1995
47	Burke 4th Series 1995 - 2.25%	—	30,000,000		546,739			09/01/1995	10/01/2032	09/01/1995
48	Burke 5th Series 1995 - 2.20%	—	27,000,000		1,398,809			09/01/1995	09/01/2032	09/01/1995
49	Coweta 1st Series 2006 - Variable	—	10,125,000		371,668			06/28/2006	06/01/2032	06/28/2006
50	Effingham 1st Series 2003 - Variable	—	13,870,000		435,117			02/19/2003	02/01/2038	02/19/2003
51	Monroe 2nd Series 2006 - Variable	—	28,065,000		1,673,206			12/13/2006	12/01/2041	12/13/2006
52	Heard 1st Series 2007 - Variable	—	17,800,000		403,140			12/06/2007	12/01/2037	12/06/2007
53	Burke 1st Series 2008 - Variable	—	68,535,000		1,902,711			11/25/2008	11/01/2048	11/25/2008
54	Burke 2nd Series 2008 - 2.93%	—	65,000,000		1,570,472			11/25/2008	11/01/2048	11/25/2008
55	Monroe 1st Series 2008 - Variable	—	83,515,000		1,509,886			11/25/2008	11/01/2048	11/25/2008
56	Monroe 1st Series 2009 - 1.00%	—	40,000,000		1,428,520			07/14/2009	07/01/2049	07/14/2009
57	Burke 1st Series 2009 - Variable	—	114,310,000		1,573,880			07/14/2009	07/01/2049	07/14/2009

58	Monroe 2nd Series 2009 - Variable	—	89,200,000		1,738,909			09/17/2009	10/01/2048	09/17/2009
59	Bartow 1st Series 2009 - 2.75%	—	173,000,000		3,580,633			09/17/2009	12/01/2032	09/17/2009
60	Appling First Series 2011 - Variable	—	67,000,000		1,127,321			09/01/2011	09/01/2041	09/01/2011
61	Monroe 1st Series 2012 - Variable	—	48,720,000		1,705,983			05/01/2012	06/01/2042	05/01/2012
62	Burke 1st Series 2012 - 2.88%	—	85,000,000		2,617,273			06/01/2012	12/01/2049	06/01/2012
63	Burke 2nd Series 2012 - 1.70%	—	100,000,000		3,194,933			06/01/2012	12/01/2049	06/01/2012
64	Burke 3rd Series 2012 - Variable	—	50,000,000		2,657,911			11/01/2012	11/01/2052	11/01/2012
65	Burke 1st Series 2013 - 2.93%	—	104,600,000		6,446,122			11/08/2013	11/01/2053	11/01/2013
66	Monroe 1st Series 2013 - Variable	—	17,500,000		1,603,424			03/21/2013	04/01/2043	03/21/2013
67	Bartow 1st Series 2013 - 2.88%	—	71,735,000		1,291,583			08/23/2013	08/01/2043	08/23/2013
68	Burke 1st Series 2018 - Variable	—	108,155,000		929,925			12/05/2018	11/01/2052	12/05/2018
69	Bartow 1st Series 2022 - Variable	—	100,000,000		372,434			11/04/2022	11/01/2062	11/04/2022
70	Bartow 2nd Series 2022 - Variable	—	100,000,000		182,696			11/04/2022	11/01/2062	11/04/2022
71	Series 2017A - 5.00%	—	270,000,000		7,564,746			09/21/2017	10/01/2077	09/01/2017
72	[a] DOE Loan 3.860% - 2044	—	500,000,000		65,433,621 [c]			02/20/2014	02/20/2044	02/20/2014
73	DOE Loan 3.488% - 2044	—	500,000,000					02/20/2014	02/20/2044	
74	DOE Loan 3.002% - 2044	—	200,000,000					12/11/2014	02/20/2044	
75	DOE Loan 3.283% - 2044	—	600,000,000					06/12/2015	02/20/2044	
76	DOE Loan 3.072% - 2044	—	400,000,000					12/09/2015	02/20/2044	

77	DOE Loan 2.571% - 2044	—	300,000,000					06/08/2016	02/20/2044	
78	DOE Loan 3.142% - 2044	—	125,000,000					12/08/2016	02/20/2044	
79	DOE Loan 3.213% - 2044	—	835,000,000					03/15/2019	02/20/2044	
80	DOE Loan 2.537% - 2044	—	2,409,117					12/20/2019	02/20/2044	
81	DOE Loan 2.537% - 2044 2	—	380,590,883		12,185,988			12/20/2019	02/20/2044	12/20/2019
82	DOE Loan 1.652% - 2044	—	519,000,000					06/05/2020	02/20/2044	
83	DOE Loan 1.737% - 2044	—	329,000,000					12/10/2020	02/20/2044	
84	DOE Loan 2.434% - 2044	—	371,000,000					06/24/2021	02/20/2044	
85	DOE Loan 2.178% - 2044	—	68,632,896					12/10/2021	02/20/2044	
86	Subtotal		20,110,529,896		226,213,979	4,228,165	35,984,402			
33	TOTAL		20,110,529,896							

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ClassAndSeriesOfObligationCouponRateDescription

In 2024, the following DOE Loan principal payments were made:

DOE Loan 3.860%, 2044	$	8,340,000
DOE Loan 3.488%, 2044		8,340,000
DOE Loan 3.002%, 2044		3,336,000
DOE Loan 3.283%, 2044		10,008,000
DOE Loan 3.072%, 2044		6,672,000
DOE Loan 2.571%, 2044		5,004,000
DOE Loan 3.142%, 2044		2,085,000
DOE Loan 3.213%, 2044		13,927,800
DOE Loan 2.537%, 2044		40,184
DOE Loan 2.537%, 2044		6,348,256
DOE Loan 1.652% 2044		8,656,920
DOE Loan 1.737% 2044		5,487,720
DOE Loan 2.434% 2044		6,188,280
DOE Loan 2.178% 2044		1,144,797
	$	85,578,957

(b) Concept: OtherLongTermDebtPrincipalAmountIssued

In 2024, the following Senior Notes were issued:

February 2024 - Series 2024A- 5.004% - $500,000,000 - due February 2027
February 2024 - Series 2024B- 5.25% - $900,000,000 - due March 2034
November 2024 - Series 2024C- Variable - $117,087,000- due November 2074
December 2024 - Series 2024D- 4.55 - $600,000,000 - due March 2030

In 2024, the following Senior Notes matured:

September 2024 - Series 2019A- 2.20% - $400,000,000 - due September 2024

(c) Concept: OtherLongTermDebtIssuanceExpense

The $65,433,621 and $12,185,988 in issuance expenses on lines 72 and 81, respectively, are related to all DOE Loan draws.

(d) Concept: InterestExpenseOtherLongTermDebt

Amortization of gain on cash flow hedge on Series 2007D Senior Note, which was redeemed in July 2012, is being credited to FERC account 427 through June 2037.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)	2,542,698,229
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See Attachment 261.1	(a) 940,541,751
9	Deductions Recorded on Books Not Deducted for Return	
10	See Attachment 261.1	(b) 936,657,865
14	Income Recorded on Books Not Included in Return	
15	See Attachment 261.1	(c) 226,320,303
19	Deductions on Return Not Charged Against Book Income	
20	See Attachment 261.1	(d) 2,831,594,774
27	Federal Tax Net Income	1,361,982,768
28	Show Computation of Tax:	
29	Federal Income Tax @ 21%	286,016,381
30	Federal Tax Credits	(89,171,430)
31	Tax Adjustment	2,613,235
32	Total Income Tax Payable	199,458,186

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FOOTNOTE DATA

(a) Concept: TaxableIncomeNotReportedOnBooks

TAXABLE INCOME NOT ON THE BOOKS

Financial Accounting Standards Board Statement No. 133 - Mark to Market	$	3,231,322
Customer Advances for Construction		39,162,244
Demand Side Management Over/Under Recovery		6,656,747
Unbilled Fuel Revenues		72,801,758
Nuclear Construction Cost Recovery		32,990,869
Fuel Clause Over/Under Recovery		737,822,127
Prepaid Rental Income		47,708,094
Other		168,590
TOTAL	**$**	**940,541,751**

(b) Concept: DeductionsRecordedOnBooksNotDeductedForReturn

EXPENSES RECORDED ON BOOKS NOT DEDUCTED ON TAX RETURN

Federal Income Tax	$	410,711,715
State Income Tax		192,017,893
Deferred Interest on Nuclear Fuel V3&4		14,814,475
Premium on Reacquired Debt (Loss)		14,637,338
Non Deductible Depreciation		103,017,167
50% Meals & Entertainment Expense		9,425,141
Environmental Remediation Reserve		4,257,297
Bad Debt Reserve		10,966,760
Employee Parking Disallowance		5,691,217
Deferred Compensation Board of Directors		3,642,496
Levelized Purchased Power		6,721,844
Transmission Parity Accrual		10,420,078
Regulatory Asset Wansley 1-2		69,999,926
Regulatory Asset COVID19 Costs		8,401,867
Regulatory Liability - Tax Reform Refunds		8,947,826
Expenditures Not Deductible Section 162/274		14,235,619
Regulatory Retired Units		42,171,060
Other Deferred Costs		6,578,146
TOTAL	**$**	**936,657,865**

(c) Concept: IncomeRecordedOnBooksNotIncludedInReturn

INCOME ON BOOKS NOT INCLUDED IN RETURN

Allowance for Funds Used During Construction - Equity	$	151,611,782
Amortization of Investment Tax Credit		35,251,079
Deferred Revenue & Expense		32,025,703
Equity in Earnings of Subs/Partnerships (SEGCO)		4,825,861
Other		2,605,878
TOTAL	**$**	**226,320,303**

(d) Concept: DeductionsOnReturnNotChargedAgainstBookIncome

DEDUCTIONS NOT CHARGED AGAINST BOOK INCOME

Administrative & General Accruals		94,398,808
Capitalized Purchase Power Agreement Southern Power Company		4,076,603
Municipal Gross Receipts Tax		3,764,869
Severance Pay Plan		12,951,641
Other Post Retirement Benefits		21,742,487
Regulatory Asset Cloud Computing		31,834,971
Other Post Employment Benefit FAS # 112		2,039,687
Regulatory Asset Bowen Deferral		40,222,281
Regulatory Asset Scherer Deferral		69,619,638
Regulatory Asset V3&4 Depreciation Deferral		12,294,719
Regulatory Asset V3&4 Financing Costs		9,508,779
Stock Based Compensation		8,414,394
Storm Damage Reserve		772,546,631
Nuclear Outage		20,321,648
Injuries and Damages Reserve		45,349,613
Pension		150,405,734
State Income Tax Payable		64,170,851
Other		5,104,064
Depreciation Related Timing Differences		1,462,827,356
TOTAL	**$**	**2,831,594,774**

CONSOLIDATION AND ALLOCATION INFORMATION

Members of Group and Tax Allocation (Note 1)		
Alabama Power Company	$	364,137,385
Alabama Property Company		(7,356,805)
Align		356,909
Aladyn		—
Georgia Power Company		199,458,186
Piedmont-Forrest Corporation		275,053
Mississippi Power Company		31,400,168
Southern Company Gas		83,576,082
Southern Electric Generating Company		12,225,043
Southern Linc		3,148,318
Southern Nuclear		589,044
Southern		(333,838,325)
So Holdings		1,924,285
SPS Holdings		(6,057,021)
So Power		(112,338,235)
Eliminations		(16,584,011)
Total Consolidation and Allocation Information	**$**	**220,916,076**

Note 1: Basis of Allocation: The consolidated federal income tax is allocated under Section 1552 (a) (1) of the Internal Revenue Code of 1986 as prescribed by Rule 45 (c) of the Securities and Exchange Commission's regulations with certain modifications approved by the Securities and Exchange Commission.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 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 amour
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 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, (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
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
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmitt
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 pertain 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 tax
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

Line No.	Kind of Tax (See Instruction 5) (a)	Type of Tax (b)	State (c)	Tax Year (d)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year (g)	Taxes Paid During Year (h)	Adjustments (i)	BALANCE AT END YEAR	
					Taxes Accrued (Account 236) (e)	Prepaid Taxes (Include in Account 165) (f)				Taxes Accrued (Account 236) (j)	Pre Ta (Inc Acc 1
1											
2	Property Tax - 2022 & Prior	Property Tax	Georgia		5,547,454	0	0	307,897	0	5,239,557	
3	Property Tax - 2023	Property Tax	Georgia		278,292,494	1,604,089	1,604,089	214,147,652	0	64,144,842	
4	Property Tax - 2024	Property Tax	Georgia		0		395,048,600	64,266,139	0	330,782,461	
5	Property Tax - 2023 & Prior	Property Tax	Alabama		852,834	0	0	0	0	852,834	
6	Property Tax - 2024	Property Tax	Alabama		0	0	2,736,460	2,736,460	0	0	
7	Property Tax - 2023 & Prior	Property Tax	Mississippi		194,844	0	0	196,522	0	(1,678)	
8	Property Tax - 2024	Property Tax	Mississippi		0	0	428,000	0	0	428,000	
9	Property Tax - 2023 & Prior	Property Tax	South Carolina		18,336	0	0	611	0	17,725	
10	Property Tax - 2024	Property Tax	South Carolina		0	0	85,454	84,854	0	600	
11	Property Tax - 2023 & Prior	Property Tax	Tennessee		18	0	0	0	0	18	
12	Property Tax - 2024	Property Tax	Tennessee		0	0	26	26	0	0	
13	Property Tax - 2023 & Prior	Property Tax	Florida		0	0	0	0	0	0	

14	Property Tax - 2024	Property Tax	Florida		0	0	0	1,325	0	(1,325)	
15	**Subtotal Property Tax**				284,905,980	1,604,089	399,902,629	281,741,486	0	401,463,034	
16	Federal Income Taxes 2023 & Prior	Income Tax			(2,848)	25,552,885	(9,711,647)	(10,312,481)	912,685	(24,042,214)	
17	Federal Income Taxes 2024	Income Tax			0		209,169,833	119,673,238	(18,320,111)	71,176,484	
18	State Income Tax	Income Tax	Georgia		37,541	16,498,594	51,726,877	7,454,093	9,830,740	37,642,471	
19	**Subtotal Income Tax**				34,693	42,051,479	251,185,063	116,814,850	(7,576,686)	84,776,741	
20	Franchise Fees - 2023	Franchise Tax	Georgia		281,506,006			228,392,125	0	53,113,881	
21	Franchise Fees - 2024	Franchise Tax	Georgia		0		247,951,292	334,950		247,616,342	
22	**Subtotal Franchise Tax**				281,506,006		247,951,292	228,727,075	0	300,730,223	
23	Net Worth	Other License And Fees Tax	Georgia		0		(66,508)	(66,508)	0	0	
24	Business License	Other License And Fees Tax	Alabama		0		9,668	9,668	0	0	
25	Business License	Other License And Fees Tax	Mississippi		0		36,720	36,720	0	0	
26	**Subtotal Other License And Fees Tax**				0		(20,120)	(20,120)	0	0	
27	FUTA	Payroll Tax	Georgia		0		327,625	327,625	0	0	
28	SUTA	Payroll Tax	Georgia		0		46,854	46,854	0	0	
29	SUTA	Payroll Tax	Alabama		0		0	0	0	0	
30	FICA	Payroll Tax	Georgia		15,469,458		0	(801,262)	0	16,270,720	
31	FICA-COVID 19 Federal	Payroll Tax	Georgia				0	0	0		
32	FICA-COVID 19 State	Payroll Tax	Georgia		0		0	0	0	0	

33	**Subtotal Payroll Tax**				15,469,458		374,479	(426,783)	0	16,270,720	
34	Motor Vehicle Tag Fees	Other Taxes and Fees	—		0		0		0	0	
35	**Subtotal Other Taxes And Fees**				0		0	0	0	0	
40	TOTAL				581,916,137	43,655,568	899,393,343	626,836,508	(7,576,686)	803,240,718	

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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%	248,206			411	27,915		220,291	56	
4	7%									
5	10%	115,092,273			411	8,022,197		107,070,076	55	
6	30	210,339,044			411	3,330,542	28,627,427	235,635,929	33	
8	TOTAL Electric (Enter Total of lines 2 thru 7)	325,679,523				11,380,654	28,627,427	342,926,296		
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)									
10										`
47	OTHER TOTAL									
48	GRAND TOTAL	325,679,523						342,926,296		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Workforce Reduction Programs	130,961	234	6,837		124,124
2	Deferred Compensation	35,436,391	131, 426.5	10,265,074	10,960,798	36,132,115
3	[a] Deferred Revenue (a)	487,626	454	110,055	38,520	416,091
4	[b] Advanced Contribution for Construction (b)	121,702,820	107,121, 451	101,954,330	144,341,213	164,089,703
5	Deferred Affiliate Taxes Payable	72,702	234	72,702		
6	Long-Term Service Agreement	39,530,464	131, 242	2,802,883	37,228,670	73,956,251
7	Contract Retention	3,469,230	143, 186, 101, 107	3,469,230	1,100,000	1,100,000
8	[c] Prepaid Rent for Outdoor Lighting (c)	7,973,856	451	46,466,096	47,460,904	8,968,664
9	Renewable Generation Collateral	17,870,188	131	5,498,311	4,089,295	16,461,172
10	Miscellaneous Deferred Credits	594,032	131, 421	150,626		443,406
11	[d] Utility Services Contracts (d)	118,376	242	9,686,221	11,284,009	1,716,164
12	[e] Distribution Services (e)	1,815,889	451	107,177		1,708,712
13	Capacity Performance Collateral		131		52,669,261	52,669,261
47	TOTAL	229,202,535		180,589,542	309,172,670	357,785,663

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FOOTNOTE DATA

(a) Concept: DescriptionOfOtherDeferredCredits
Atlanta-Jacksonville Prepaid Fiber Maintenance and Right of Way Encroachment is being amortized over 10 years and 22 years ending in 2024 and 2025, respectively. Macon Ring and Macon Spur Prepaid Fiber is being amortized over 20 years and 24 years ending in 2027 and 2026, respectively.
(b) Concept: DescriptionOfOtherDeferredCredits
Deferred credits for Contributions in Aid of Construction (CIAC) are cash advances from customers related to capital projects which are used to offset CWIP costs when incurred. Prepaid on-going maintenance over $250K for CIAC requires amortization over the life of the asset.
(c) Concept: DescriptionOfOtherDeferredCredits
Prepaid Rent for Outdoor Lighting is amortized over a 24-month period beginning in the month the payment is received.
(d) Concept: DescriptionOfOtherDeferredCredits
Deferred revenue from Utility Service Contracts is being amortized over the life of the contract which is 25 years.
(e) Concept: DescriptionOfOtherDeferredCredits
Maintenance on Atlanta Airport network underground facilities at the End Around Relocation and Concourse is being amortized over 29 years ending 2036 and 35 years ending 2043, respectively. The Dekalb County Water Plant Substation is being amortized over 33 years ending in 2043.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				Balance End of Ye (k)
							Debits		Credits		
			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)	
1	Accelerated Amortization (Account 281)										
2	Electric										
3	Defense Facilities										
4	Pollution Control Facilities	529,573,839	17,587,711	85,988,450			182, 254	4,367,068	182, 254	26,638,625	483,444,6
5	Other										
5.1	Other (provide details in footnote):										
8	TOTAL Electric (Enter Total of lines 3 thru 7)	529,573,839	17,587,711	85,988,450				4,367,068		26,638,625	483,444,6
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)	529,573,839	17,587,711	85,988,450				4,367,068		26,638,625	483,444,6
18	Classification of TOTAL										
19	Federal Income Tax	430,852,661	11,443,670	65,037,474			182, 254	859,178	182, 254	23,137,145	399,536,8
20	State Income Tax	98,721,178	6,144,041	20,950,976			182, 254	3,507,890	182, 254	3,501,480	83,907,8
21	Local Income Tax										

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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
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				ADJUSTMENTS			
							Debits		Credits	
			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)	Am
1	Account 282									
2	Electric	4,393,512,361	157,583,491	162,579,611			182/254	44,350,269	182/254/282	123,
3	Gas									
4	Other (Specify)	40,761,667	(1,093,364)	(40,034,156)						
5	Total (Total of lines 2 thru 4)	4,434,274,028	156,490,127	122,545,455				44,350,269		123,
6	Other Income and Deductions	(375,424,674)			(364,637,497)	(101,042,768)			282	
7	CWIP Electric	(187,887,534)		(180,822,436)						
8	CWIP NonElectric	(362,419,921)			362,419,921					
9	TOTAL Account 282 (Total of Lines 5 thru 8)	3,508,541,899	156,490,127	(58,276,981)	(2,217,576)	(101,042,768)		44,350,269		123,
10	Classification of TOTAL									
11	Federal Income Tax	2,836,557,276	128,471,573	(81,124,071)	(1,853,655)	(67,016,731)	182/254	23,384,526	182/254	106,
12	State Income Tax	671,984,623	28,018,554	22,847,090	(363,921)	(34,026,037)	182/254	20,965,743	182/254	17,
13	Local Income Tax									

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 28
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.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR				ADJUSTMENTS				E
			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)	Debits		Credits		
							Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	
1	Account 283										
2	Electric										
3	Premium on Reacquired Debt	52,606,441	113,099	5,012,992							
4	Additional Pension Deduction	445,692,745	33,538,065	9,398,947							4
5	Other Basis Differences - 109	116,733,053	792	1,812			182/254	16,359,593	182/254	17,922,907	
6	Other *	828,723,487	420,576,252	439,922,240			182/254		182/254		[(a)]8
9	TOTAL Electric (Total of lines 3 thru 8)	1,443,755,726	454,228,208	454,335,991				16,359,593		17,922,907	1,4
10	Gas										
11											
12											
13											
14											
15											
16											
17	TOTAL Gas (Total of lines 11 thru 16)										
18	TOTAL Other	40,416,112			198,293	40,609,656					
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	1,484,171,838	454,228,208	454,335,991	198,293	40,609,656		16,359,593		17,922,907	1,4
20	Classification of TOTAL										

21	Federal Income Tax	1,136,064,548	360,811,010	339,042,013	(35,404)		182/254	10,855,975	182/254	14,211,894	1,1
22	State Income Tax	348,107,290	93,417,198	115,293,978	233,697	40,609,656	182/254	5,503,618	182/254	3,711,013	2
23	Local Income Tax										
NOTES											

FOOTNOTE DATA

(a) Concept: AccumulatedDeferredIncomeTaxesOther

	12/31/2023	DR 410.1	CR 411.1	Debit Adj	Credit Adj	12/31/2024
Customer Advances on Const.	$ (27,539,998)	$ 13,655,117	$ (23,318,022)	$ —	$ —	$ (37,202,903)
Deferred Interest on Nuclear Fuel	10,183,407	142,769	(4,220,041)	—	—	6,106,135
Deferred Jobs Revenue	1,544,391	236,953	(1,191,361)	—	—	589,983
Emission Allowances	1,925,932	109	(43,703)	—	—	1,882,338
Unbilled Rev. - Flat Bill	9,201,994	21,432,553	(21,535,400)	—	—	9,099,147
Fuel Clause Recovery	507,786,016	1,978,308	(205,055,799)	—	—	304,708,525
Levelized Purchase Power	2,317,120	15,129,579	(16,931,950)	—	—	514,749
Nuclear Construction Cost Recovery	11,293,504	169,832	(9,016,484)	—	—	2,446,852
Nuclear Outage	8,704,347	9,274,754	(4,146,167)	—	—	13,832,934
Reg. Asset - Cloud Computing	22,341,982	8,371,681	(515,782)	—	—	30,197,881
Reg. Asset - COVID-19 Costs	4,479,939	61,170	(2,347,017)	—	—	2,194,092
Reg. Asset - Customer Usage Data Costs	40,406	1,428	(70,679)	—	—	(28,845)
Reg. Asset - Deferred Plant Depreciation	33,813,986	32,719,915	(1,517,298)	—	—	65,016,603
Reg. Asset - IQTBEE Program	7,435	38	(1,610)	—	—	5,863
Reg. Asset - TOU MB Revenue Erosion	354,114	57,365	(288,078)	—	—	123,401
Reg. Asset - Nuclear Financing	3,640,558	2,981,370	(572,779)	—	—	6,049,149
Reg. Asset - Obsolete Inv	3,218,358	3,580,246	(3,741,675)	—	—	3,056,929
Reg. Asset - Retired Units	220,957,968	1,683,350	(35,421,450)	—	—	187,219,868
Reg. Liability - GA Rate Change Savings	—	—	(2,336,665)	—	—	(2,336,665)
Storm Damage	14,452,028	309,099,715	(107,650,280)	—	—	215,901,463
	$ 828,723,487	**$ 420,576,252**	**$ (439,922,240)**	**$ —**	**$ —**	**$ 809,377,499**

NOTE 1: DITS associated with Premium on Reacquired Debt relate to the premium on the reacquisition of certain series of first mortgage and pollution control bonds. This loss on reacquisition is recognized for tax return purposes in the year incurred, but amortized over various periods for book purposes.

NOTE 2: DITS on Additional Pension Deduction relate to actual pension costs that impact the pension fund and are currently recognized for tax return purposes. For book purposes, a deduction is taken as the pension costs are accrued.

NOTE 3: DITS on Other Basis Differences - 109 represent the tax effects of temporary differences created with FAS 109.

NOTE 4: DITS on Deferred Jobs Revenues represent revenues that have been billed for jobbing work done. The revenues are deferred on the books until all costs are accumulated. For tax purposes, the revenues are recognized currently.

NOTE 5: DITS on Emission Allowances represent actual cash payments deducted on the tax return for the purchases of emission allowances versus book accounting, which accounts for the allowances using an average weighted cost basis.

NOTE 6: DITS on Unbilled Revenues associated with Flat Bill program represent tax effect of differences between customer actual usage and contracted usage related revenues.
NOTE 7: DITS on Fuel Clause Recovery relate to recognition of the under recovery of fuel costs in revenues for book purposes currently, while these revenues are recognized for tax purposes when actually collected.

NOTE 8: DITS on Levelized Purchase Power relate to actual capacity expenses which are recognized as paid for tax purposes. For book purposes, these costs will be levelized over the term of the purchase agreement.

NOTE 9: DITS on Nuclear Outage relate to expenses incurred during scheduled outages at nuclear facilities, which are deferred on the books per a GPSC retail rate order. For book purposes, these costs will be amortized over the GPSC mandated recovery period. For tax purposes, these costs are deducted as incurred.

NOTE 10: DITS on Nuclear Construction Cost Recovery are related to the billed amounts to customers for the recovery of financing cost associated with building a nuclear plant.

NOTE 11: DITS on Other Deferred Costs - Electric are miscellaneous temporary differences.

NOTE 12: DITS on Regulatory Asset Obsolete Inventory are associated with the inventory determined to be obsolete related to the retirement of Plant Branch Units 3 and 4.

NOTE 13: Regulatory Asset Cancelled Construction Projects are associated with the cost deferrals of cancelled construction projects for retired units. These cost are expected to be amortized for books over nine years beginning in January 2014.

NOTE 14: DITS on Regulatory Assets Retired Units are associated with Net Book Value that will be amortized over the remaining useful life of the unit.

NOTE 15: DITS on Customer Advances on Construction are funds received from customers for construction work requested by customer. For tax, the funds are taxable upon receipt.

NOTE 16: DITS on Storm Damage represent actual costs deducted on the tax return as incurred, which have exceeded the book accrual allowed by the GPSC.

NOTE 17: DITS on Other Income & Deductions represent the tax effect associated with FAS 133, Non-Utility Deferred Intercompany Gains, and miscellaneous differences. Deferred Intercompany Gains relate to the gain on the sale of transmission properties to Gulf Power Company (now Florida Power and Light Company), gain on the sale of computer equipment to Southern Company Services, and gain on sale of property to Southern Power Company.

NOTE 18: DITS on regulatory liability for GA rate change savings are related to the change in current tax expense from GA income tax rate change.

NOTE 19: DITS on Regulatory Asset Customer Usage Data Costs represent costs to be recovered for acquiring customer usage data.

NOTE 20: DITS on Deferred Interest Nuclear Fuel relate to the deferral of capitalized interest on nuclear fuel for Plant Vogtle Units 3 &4.

NOTE 21: DITS on Reg. Asset – Cloud Computing are associated with the deferral of certain costs related to the implementation of new cloud based business applications used by the Company.

NOTE 22: DITS on Reg. Asset - IQTBEE (Income Qualified Tariff Based on Energy Efficiency) are related to a program for retail customers that provides energy efficiency upgrades to income qualified customers.

NOTE 23: DITS on Reg. Asset - COVID-19 costs are associated with recoverable costs from the COVID-19 pandemic.
NOTE 24: DITS on Reg. Asset - TOU MB Revenue Erosion are related to the regulatory asset created for tracking revenue erosion from Georgia Power customers using the "time of use - medium business rate."

NOTE 25: DITS on Reg. Asset - Deferred Plant Depreciation are related to the PSC approved deferral of depreciation for Plant Scherer Units 1-3, Bowen Units 1 & 2, and Vogtle Unit 3.

NOTE 26: DITS on Reg. Asset - Nuclear Financing are related to the deferred financing costs on Vogtle Unit 3 as ordered by the PSC.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	(a) Deferred Income Taxes	2,160,720,965	190,411	590,871,332	476,848,098	2,046,697,731
2	(b) State Tax Expense Savings				111,279,375	111,279,375
3	(c) External Decommissioning Liability	664,995,522	128		70,265,115	735,260,637
4	(d) Asset Retirement Obligations	316,853,921	182,411	273,429,055	132,220,092	175,644,958
5	(e) Gas and Electric Hedges	11,471,020	Various	12,144,030	19,718,688	19,045,678
6	(f) DSM Over Recovery	45,831,182	440,442		6,656,747	52,487,929
7	(g) Retiree Benefit Plans	104,909,388	926	21,340,642	324,297	83,893,043
8	(h) Plant Retirements	5,720,598	407.4	2,882,799	14,947	2,852,746
9	(i) Nuclear Decommissioning	20,554,455	407.4	12,746,126	15,760,189	23,568,518
10	(j) Customer Usage Data Access				110,451	110,451
41	TOTAL	3,331,057,051		913,413,984	833,197,999	3,250,841,066

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FOOTNOTE DATA

(a) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The protected excess accumulated deferred income taxes associated with the remeasurement of Accumulated Deferred Income Taxes as a result of the Tax Cuts and Jobs Act are amortized over the related remaining property lives using the average rate assumption method in accordance with IRS normalization principles which may range up to 54 years. In April 2024, the State of Georgia enacted tax legislation that reduced the corporate income tax rate from 5.75% to 5.39% effective for the 2024 tax year. The legislation triggered a remeasurement, in the second quarter of 2024, of the Company's existing accumulated deferred income tax balances by approximately $102 million that was recorded as a regulatory liability. The amortization of this customer benefit will be amortized completely in 2025. The deferred tax assets and regulatory liabilities associated with the remaining unamortized investment tax credits are being amortized over the related remaining property lives in accordance with IRS normalization principles which may range up to approximately 43 years.

	Beginning Balance	Amortized to 411.1	Net DR/CR Adj	Ending Balance
Deferred Income Taxes	$ 77,408,550	$ —	$ 863,079	$ 78,271,629
Protected EADIT	$ 2,083,312,415	$ (77,131,579)	$ (37,754,734)	$ 1,968,426,102
Unprotected EADIT GA Rate Change OATT Included		$	$ 78,662,385	$ 78,662,385
Unprotected EADIT GA Rate Change OATT Excluded		$	$ 23,669,164	$ 23,669,164

(b) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In April 2024, the State of Georgia enacted tax legislation that reduced the corporate income tax rate from 5.75% to 5.39% effective for the 2024 tax year. The legislation triggered an update to the current year tax expense, resulting in $9 million of tax expense savings that was recorded as a regulatory liability. As ordered by the Georgia PSC in the 2025 Compliance Filing in Docket No. 44280, the amortization of this customer benefit is effective January 1, 2025 over a one-year period.

(c) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Effective January 1, 2023, no funding will be accrued for the Plant Hatch Units 1 and 2 and Plant Vogtle Units 1 and 2 external nuclear decommissioning trusts until the next base rate case as ordered by the Georgia PSC in Docket No. 44280. Effective August 1, 2023, the Company is accruing $7.6 million annually until the next base rate case, as ordered by the Georgia PSC in Docket No. 43838, for the funding of future costs related to decommissioning Plant Vogtle Unit 3. As ordered by the Georgia PSC in Docket No. 29849, and as a result of Plant Vogtle Unit 4 being placed in service on April 29, 2024, the Company is accruing $7.8 million annually effective May 1, 2024 until the next base rate case, for the funding of future costs related to decommissioning Plant Vogtle Unit 4.

(d) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Coal Combustion Residuals (CCR) AROs are recovered through the Environmental Compliance Cost Recovery tariff, with approximately $160 million and $100 million recovered in 2023 and 2024, respectively, and approximately $220 million expected to be recovered in 2025, with the recovery amount for 2026 and future years updated through future regulatory proceedings. Effective January 1, 2023, approximately $17 million annually is being recovered for non-CCR AROs through traditional base tariffs through December 31, 2025. Other cost of removal obligations and non-CCR AROs are recovered over the related property lives, which may range up to 54 years.

(e) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

Realized and unrealized gains arising from marked to market gas and electric hedges are deferred and recovered when settled as ordered by the Georgia PSC in Docket No. 16134. The Company's natural gas hedging program uses an array of derivative instruments within a 36-month time horizon, as ordered by the Georgia PSC in Docket No. 43011.

(f) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The costs associated with Demand-Side Management (DSM) initiatives are recovered through the DSM tariffs, and the revenues and expenses are trued-up based on actual results. The over or under recovery from the previous year is applied to the DSM tariffs in the year after a full calendar year through the annual compliance filings.

(g) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

The credits associated with retiree benefit plans resulted from a change in valuation methodology and are being amortized over 13 years ending December 31, 2032.

(h) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In accordance with the Georgia PSC order in Docket No. 44280, the credit balance of the remaining net book values of Plant Boulevard Unit 1, Plant McIntosh Unit 1, and Plant Langdale Units 5 and 6 as of December 31, 2022 is being amortized over a three-year period ending December 31, 2025.

(i) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In accordance with the Nuclear Regulatory Commission requirement to satisfy funding assurance for nuclear decommissioning, the Company provided funding to the external nuclear decommissioning trust for Plant Vogtle Unit 3 of $7.6 million in 2022. In 2023, the Company funded $0.8 million, $7.6 million, and $7.8 million related to Plant Vogtle Units 1, 3, and 4, respectively. Effective August 1, 2023, the Company is amortizing $7.6 million annually until the next base rate case, as ordered by the Georgia PSC in Docket No. 43838, for the funding of future costs related to decommissioning Plant Vogtle Unit 3. As ordered by the Georgia PSC in Docket No. 29849, and as a result of Plant Vogtle Unit 4 being placed in service on April 29, 2024, the Company is amortizing $7.8 million effective May 1, 2024 until the next base rate case, for the funding of future costs related to decommissioning Plant Vogtle Unit 4. The recovery of the $0.8 million of funding for Plant Vogtle Unit 1 will be determined by the Georgia PSC in the next base rate case.

(j) Concept: DescriptionAndPurposeOfOtherRegulatoryLiabilities

In accordance with the Georgia PSC order in Docket No. 44280, costs associated with investigation and implementation of providing hourly usage information to all metered customers is to be recovered over a three-year period ending December 31, 2025. In the third quarter 2024, recovery of these costs in a regulatory asset, FERC 182.3, exceeded total expenditures of the program and the excess recovered amount is classified as a regulatory liability and amortization will be determined by the Georgia PSC in future regulatory proceedings.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	4,509,930,485	4,039,663,405	29,113,358	27,622,686	2,429,276	2,387,722
3	(442) Commercial and Industrial Sales						
4	Small (or Comm.) (See Instr. 4)	3,909,397,429	3,550,813,715	34,048,112	32,607,165	330,430	327,465
5	Large (or Ind.) (See Instr. 4)	1,678,490,643	1,535,076,602	23,654,325	23,475,989	10,581	10,661
6	(444) Public Street and Highway Lighting	86,563,800	82,560,322	258,462	280,071	9,472	9,412
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways	11,591,408	10,512,196	151,669	144,124	1	1
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	10,195,973,765	9,218,626,240	87,225,926	84,130,035	2,779,760	2,735,261
11	(447) Sales for Resale	291,730,866	196,324,295	4,618,241	2,635,740		
12	TOTAL Sales of Electricity	10,487,704,631	9,414,950,535	91,844,167	86,765,775	2,779,760	2,735,261
13	(Less) (449.1) Provision for Rate Refunds	[a](35,559,304)	329,178				
14	TOTAL Revenues Before Prov. for Refunds	10,523,263,935	9,414,621,357	91,844,167	86,765,775	2,779,760	2,735,261
15	Other Operating Revenues						

16	(450) Forfeited Discounts	17,156,197	16,674,049				
17	(451) Miscellaneous Service Revenues	[b]300,973,324	[d]270,534,357				
18	(453) Sales of Water and Water Power	655,483	461,410				
19	(454) Rent from Electric Property	35,651,765	27,144,036				
20	(455) Interdepartmental Rents						
21	(456) Other Electric Revenues	[c]78,919,784	[e]56,512,086				
22	(456.1) Revenues from Transmission of Electricity of Others	108,200,767	115,793,238				
23	(457.1) Regional Control Service Revenues						
24	(457.2) Miscellaneous Revenues						
25	Other Miscellaneous Operating Revenues						
26	TOTAL Other Operating Revenues	541,557,320	487,119,176				
27	TOTAL Electric Operating Revenues	11,064,821,255	9,901,740,533				

Line12, column (b) includes $ of unbilled revenues.
Line12, column (d) includes MWH relating to unbilled revenues

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ProvisionForRateRefunds

Provision for rate refund

(b) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues (Account 451)		**2024**
Outdoor Lighting	$	235,540,033
Transmission Maintenance Fees		32,167,972
Account Charges		18,479,610
Reconnect Fees		6,982,475
Returned Check Fees		5,890,485
Renewable Program Fees		1,953,631
Miscellaneous Small Items (each under $250,000)		(40,882)
Total Miscellaneous Service Revenues (Account 451)	$	300,973,324

(c) Concept: OtherElectricRevenue

Other Electric Revenues (Account 456)		**2024**
Integrated Transmission System O&M Revenue	$	28,920,385
Transmission Construction Project Revenue		19,253,399
Scheduling, System Control and Dispatching		7,256,169
Rate Administration Charges		6,820,166
Spare Equipment Carrying Charge		5,679,317
Renewable Program Bid Fees		5,423,317
Transmission Service Agreements		4,662,444
Renewable Program Fees		4,456,324
Compensation for Collecting Sales Tax		4,177,267
Miscellaneous Small Items (each under $250,000)		3,734,982
EV Charging Station		2,205,821
Colocation		2,124,857
Revenue from Operation of Fish and Wildlife		1,918,794
Revenues from Additional Regulated Services		1,414,461
Joint Use Poles		708,034
Transmission Interconnection Termination		475,000
Land Related Revenue		317,965
Encroachment Fees		268,271
Realized loss on Price Protection Products		(20,897,189)
Total Other Electric Revenues (Account 456)	$	78,919,784

(d) Concept: MiscellaneousServiceRevenues

Miscellaneous Service Revenues (Account 451)		**2023**
Outdoor Lighting	$	212,137,196
Transmission Maintenance Fees		24,509,383
Account Charges		17,897,944
Reconnect Fees		8,509,177
Returned Check Fees		6,177,509
Renewable Program Fees		1,163,230
Miscellaneous Small Items (each under $250,000)		139,918
Total Miscellaneous Service Revenues (Account 451)	$	270,534,357

(e) Concept: OtherElectricRevenue

Other Electric Revenues (Account 456)	2023	
Integrated Transmission System O&M Revenue	$	27,403,192
Rate Administration Charges		6,721,302
Scheduling, System Control and Dispatching		6,563,779
Spare Equipment Carrying Charge		6,111,748
Compensation for Collecting Sales Tax		3,750,156
Colocation		2,287,798
Revenue from Operation of Fish and Wildlife		2,264,028
Renewable Program Fees		1,509,543
Miscellaneous Small Items (each under $250,000)		1,482,884
Revenues from Additional Regulated Services		1,403,500
Renewable Program Fees		1,388,245
Joint Use Poles		1,135,007
EV Charging Stations		1,027,800
Transmission Interconnection Termination		674,995
Encroachment Fees		288,182
Land Related Revenue		258,204
Realized loss on Price Protection Products		(3,893,149)
Transmission Service Agreements		(3,865,128)
Total Other Electric Revenues (Account 456)	$	56,512,086

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)
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46	TOTAL				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	R-M Residential: Multi-Unit	13,182	2,223,736	1,828	7,211	0.1687
2	R Residential	21,853,280	3,571,923,773	1,906,808	11,461	0.1635
3	TOU-REO Time-of-Use - Residential Energy Only	83,717	13,057,102	6,332	13,221	0.1560
4	TOU-PEV Time-of-Use - Plug In Electric Vehicle	278,296	40,909,144	14,207	19,589	0.1470
5	OL_NGRE Outdoor Lighting	34,217	13,102,492	3,778	9,057	0.3829
6	OL-UN Outdoor Lighitng	21,157	2,633,601	3,173	6,668	0.1245
7	FLAR-R Flat Bill - Residential	4,965,753	847,460,188	350,261	14,177	0.1707
8	FLAT-GS Flat Bill - General Service	198	52,203	29	6,836	0.2633
9	PLS-R Power & Light - Small	33,392	5,154,689	734	45,494	0.1544
10	PLM-R Power & Light - Medium	121,039	15,059,368	179	676,198	0.1244
11	PLL-R Power & Light - Large	30,898	4,213,011	9	3,433,159	0.1364
12	Pre pay	1,029,549	175,195,706	77,478	13,288	0.1702
13	TOU-RD Time-of-Use - Residential Demand	722,975	125,260,041	60,806	11,890	0.1733
14	GS-R General Service	12,267	4,078,706	3,654	3,357	0.3325
41	TOTAL Billed Residential Sales	29,199,920	4,820,323,760	2,429,276	12	0.1651
42	TOTAL Unbilled Rev. (See Instr. 6)	(86,562)	(310,393,275)			3.5858
43	TOTAL	29,113,358	4,509,930,485	2,429,276	12	0.1549

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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.
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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	SCH School Service	157,326	26,180,555	1,007	156,232	0.1664
2	SLM School Load Management	1,725,601	192,165,720	1,279	1,349,180	0.1114
3	TOU-HLF Time of Use - High Load Factor	62,640	6,894,990	15	4,176,013	0.1101
4	OLNG-BB Outdoor Lighting	12,409	1,565,544	2,292	5,414	0.1262
5	OL-NGRE Outdoor Lighting	53,735	12,895,416	4,192	12,818	0.2400
6	RTPHSLM Real Time Pricing Hour Ahead - School Load Management	38,895	3,011,898	1	38,895,158	0.0774
7	RTPDSCH Real Time Pricing Day Ahead - School Service	132,573	12,031,833	74	1,791,523	0.0908
8	RTPDSCH Real Time Pricing Day Ahead - School Load Management	578,535	53,171,642	190	3,044,920	0.0919
9	OL-UN Outdoor Lighting	315,198	39,785,740	20,747	15,192	0.1262
10	UC Unmetered Communication	103,050	24,158,241	17,710	5,819	0.2344
11	FLAT-GS Flat Bill - General Service	63,584	15,726,600	6,742	9,431	0.2473
12	RTPDHLF RTP Day Ahead - Time of Use High Load Factor	195,507	19,126,581	48	4,073,054	0.0978
13	TOU-MB Time of Use - Multiple Business	688,388	92,844,336	3,014	228,397	0.1349
14	PLS-C Power & Light - Small	3,087,034	538,933,494	63,256	48,802	0.1746
15	PLM-C Power & Light - Medium	9,762,038	1,430,984,990	33,554	290,935	0.1466
16	PLL-C Power & Light - Large	1,795,988	230,217,135	368	4,880,402	0.1282
17	TOUGSD-C Time of Use - General Service Demand	301,339	42,845,026	417	722,636	0.1422
18	OGS-C Optional General Service	4,005	1,221,894	163	24,568	0.3051
19	IOP-C Irrigation Off-Peak	44,658	6,761,170	700	63,798	0.1514
20	G-C Governmental	100,410	11,447,946	11	9,128,143	0.1140

21	GS-C General Service	1,260,615	319,934,971	164,540	7,661	0.2538
22	TOUEO-C Time-of-Use - Energy Only	568,976	94,721,164	6,354	89,546	0.1665
23	SASND-C Seasonal Agricultural Service - Non-Demand	1,066	194,628	31	34,375	0.1826
24	RTPHPLLC Real Time Pricing Hour Ahead - Power & Light Large	2,581,365	152,836,429	21	122,922,165	0.0592
25	RTPHGC RTP Hour Ahead/G-COM	198,458	16,263,740	3	66,152,617	0.0820
26	RTPGOVC Real Time Pricing Day Ahead - Governmental	128,528	12,492,746	7	18,361,153	0.0972
27	RTGSDC Real Time Pricing Day Ahead - Time of Use - General Service Demand	134,916	14,391,654	38	3,550,415	0.1067
28	RTPDPLLC Real Time Pricing Day Ahead - Power & Light Large	2,579,826	247,448,495	241	10,704,672	0.0959
29	RTPDPLMC Real Time Pricing Day Ahead - Power & Light Medium	2,704,334	215,948,235	967	2,796,623	0.0799
30	FPA- COM Fixed Pricing Alternative	785,917	81,016,372	168	4,678,079	0.1031
31	SAS-COM Seasonal Agricultural Service	20,511	2,475,421	199	103,073	0.1207
32	APS-COM Agricultural Process Service	10,102	1,254,708	45	224,497	0.1242
33	FSTOU-C Farm Service	69,547	10,170,316	1,801	38,616	0.1462
34	RTPDTEOC Real Time Pricing Day Ahead - Time of Use	5,113	356,380	5	1,022,562	0.0697
35	TOUSCFC Time of Use - Supplier Choice FPO	124,202	4,579,079	38	3,268,484	0.0369
36	RTDFPAC RTP Day Ahead - Fixed Pricing Alternative	47,466	5,398,661	11	4,315,063	0.1137
37	TOUSC-C Time of Use Supplier Choice	128,596	9,452,059	47	2,736,075	0.0735
38	TOURN-C Time of Use Revenue Neutral	314,139	33,549,885	53	5,927,159	0.1068
39	RTDRN-C RTP Day Ahead - Revenue Neutral	1,044,745	91,533,923	67	15,593,214	0.0876
40	RTHRN-C RTP Hour Ahead - Revenue Neutral	2,092,997	128,407,483	10	209,299,744	0.0614
41	RTDPLSC RTP Day Ahead - Power & Light Supplier Choice	15,611	883,250	4	3,902,672	0.0566
41	TOTAL Billed Small or Commercial	34,039,943	4,205,280,350	330,430	103	0.1235
42	TOTAL Unbilled Rev. Small or Commercial (See Instr. 6)	8,169	(295,882,921)			(36.2219)
43	TOTAL Small or Commercial	34,048,112	3,909,397,429	330,430	103	0.1148

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	OL-NGRE Outdoor Lighting	1,938	475,692	120	16,149	0.2455
2	OL-UN Outdoor Lighting	14,893	1,851,364	411	36,236	0.1243
3	FLAT-GS Flat Bill - General Service	246	60,556	36	6,829	0.2463
4	PLS-I Power & Light - Small	62,417	10,486,971	1,211	51,542	0.1680
5	PLM-I Power & Light - Medium	979,856	141,445,281	2,289	428,071	0.1444
6	PLL-I Power & Light - Large	676,199	85,662,583	129	5,241,854	0.1267
7	TOUGSD-I Time of Use - General Service Demand	196,032	27,931,478	162	1,210,072	0.1425
8	OGS-I Optional General Service	8,091	2,155,789	67	120,762	0.2664
9	IOP-I Irrigation Off-Peak	2,867	305,458	17	168,648	0.1065
10	GS- I General Service	29,438	7,515,180	4,045	7,281	0.2553
11	TOUEO-I Time-of-Use - Energy Only	44,677	7,349,615	866	51,590	0.1645
12	SASND-I Seasonal Agricultural Service - Non-Demand	403	76,487	17	23,708	0.1898
13	RTPHPLLI Real Time Pricing Hour Ahead - Power & Light Large	4,891,646	288,144,816	60	81,527,441	0.0589
14	RTHPLMI Real Time Pricing Hour Ahead - Power & Light Medium	605,374	27,285,591	30	20,179,118	0.0451
15	RTPDGSDI Real Time Pricing Day Ahead - Time of Use - General Service Demand	197,607	18,870,900	39	5,066,843	0.0955
16	RTPHGSDI Real Time Pricing Hour Ahead - Time of Use - General Service Demand	50,241	2,544,420	3	16,747,097	0.0506
17	RTPDPLLI Real Time Pricing Day Ahead - Power & Light Large	2,661,411	223,070,971	191	13,934,089	0.0838
18	RTDPLMI Real Time Pricing Day Ahead - Power & Light Medium	1,617,123	102,384,632	297	5,444,857	0.0633
19	FPA-IND Fixed Pricing Alternative	1,343,898	120,413,578	121	11,106,597	0.0896

20	SASIND Seasonal Agricultural Service	7,007	787,513	57	122,929	0.1124
21	APS-IND Agricultural Process Service	48,136	5,139,550	98	491,184	0.1068
22	FSTOU-I Farm Service Time of Use	279	38,020	7	39,841	0.1363
23	RTHTEOI Real Time Pricing Hour Ahead - Time Of Use - Energy Only	2,645	175,235	4	661,269	0.0662
24	RTDTEOI Real Time Pricing Day Ahead - Time Of Use - Energy Only			0	0	0.0000
25	RTPDAPSI Real Time Pricing Day Ahead - Agricultural Process Service	34,962	2,299,137	5	6,992,336	0.0658
26	TOUSCFI Time of Use Supplier Choice FPO	310,801	10,434,682	7	44,400,172	0.0336
27	RTDFPAI RTP Day Ahead - Fixed Pricing Alternative	196,055	16,846,106	18	10,891,919	0.0859
28	TOUSCI Time of Use Supplier Choice	194,740	16,883,700	14	13,909,974	0.0867
29	RTHFPAI RTP Hour Ahead - Fixed Pricing Alternative	197,749	12,581,561	2	98,874,356	0.0636
30	TOURN-I Time of Use Revenue Neutral	720,636	70,528,355	50	14,412,727	0.0979
31	RTDRN-I RTP Day Ahead - Revenue Neutral	1,869,374	160,689,378	117	15,977,556	0.0860
32	RTHRN-I RTP Hour Ahead - Revenue Neutral	6,280,317	409,752,192	62	101,295,461	0.0652
33	RTDPLSI RTP Day Ahead/PLS-IND	60,946	1,836,120	3	20,315,475	0.0301
34	RTHPLSI RTP Hour Ahead/PLS-IND	122,949	4,249,739	2	61,474,340	0.0346
35	TOUMBI Time of Use --Multiple business	1,638	210,585	23	71,214	0.1286
36	EAF-IND Electric Arc Furnace	291,486	20,526,092	1	291,486,022	0.0704
41	TOTAL Billed Large (or Ind.) Sales	23,724,077	1,801,009,327	10,581	2,243	0.0758
42	TOTAL Unbilled Rev. Large (or Ind.) (See Instr. 6)	(69,752)	(122,518,684)			1.7565
43	TOTAL Large (or Ind.)	23,654,325	1,678,490,643	10,581	2,236	0.0709

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	RLG Roadway Lighting Governmental	126,818	66,775,245	1,746	72,633	0.5265
2	OL-Govt Outdoor Lighting - Governmental	93,655	19,860,715	2,534	36,959	0.2121
3	TC Traffic Control	32,956	2,402,319	4,512	7,303	0.0729
4	OL-UN Outdoor Lighting	1,355	170,669	140	9,678	0.1260
5	TC-M Traffic Control Metered	3,678	481,087	540	6,812	0.1308
41	TOTAL Billed Public Street and Highway Lighting	258,462	89,690,035	9,472	27	0.3470
42	TOTAL Unbilled Rev. (See Instr. 6)		(3,126,235)			
43	TOTAL	258,462	86,563,800	9,472	27	0.3349

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Marta Electric Transportation	151,669	12,603,827	1	151,669	0.0831
41	TOTAL Billed Sales To Railroads and Railways	151,669	12,603,827	1	151,669	0.0831
42	TOTAL Unbilled Rev. (See Instr. 6)		(1,012,419)			
43	TOTAL	151,669	11,591,408	1	151,669	0.0764

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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						
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40						
41	TOTAL Billed Provision For Rate Refunds					
42	TOTAL Unbilled Rev. (See Instr. 6)					
43	TOTAL		[(a)](35,559,304)			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: ProvisionForRateRefunds
Provision for rate refund

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	87,374,071	10,928,907,299	2,779,760	31,432	
42	TOTAL Unbilled Rev. (See Instr. 6) - All Accounts	(148,145)	[a](732,933,534)			
43	TOTAL - All Accounts	87,225,926	10,195,973,765	2,779,760	31,432	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: RevenueFromSalesOfElectricityByRateSchedulesUnbilled

The Total Unbilled Rev included in total sales of electricity on pg 300 line 12 is ($732,933,534). The Total Unbilled Rev on pg 304 line 47 includes $45,028,150 of Unbilled Revenue. The difference of ($777,961,684) is adjustments including:

FCR	$	(737,822,127)
NCCR		(32,990,869)
DSM		(6,656,747)
Flatbill Revenue Recognition		327,873
Miscellaneous		(819,814)
Total Difference	$	(777,961,684)

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 dur the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlen 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 interes 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 pro 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 del 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 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 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 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 c 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 bil demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) deman 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 integr 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 m 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, 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 th 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-I 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			Tota (h+ (
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)		Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	
1	Associated Energy Cooperative Inc.	OS	T4				7,775		174,056		1
2	City of Dalton, Dalton Utilities	LU	T4				6,899	390,981	380,363		7

3	City of Tallahassee, Florida	OS	T4				5,146		233,190		2
4	City of Troy, Alabama	OS	T5						34,661		
5	Constellation Energy	OS	T5						95,595		
6	Dominion Energy	OS	T4				14,018		179,399		1
7	Duke Energy Carolinas, LLC	OS	T4				8,034		240,630		2
8	Duke Energy Florida	OS	T4				19,718		933,813		9
9	Eagle Energy Partners I, L.P.	OS	T4				10,970		340,512		3
10	Endure Energy, LLC	OS	T4								
11	Energy United Electric Membership Corporation	LU	T4				137,337	14,766,668	6,175,947		20,9
12	Exelon Generation Company, LLC	OS	T4				47,214		1,575,605		1,5
13	Flint EMC	LU	T4				125,377	16,766,937	6,218,553		22,9
14	Florida Power & Light Company	OS	T4				833,149	14,032,900	8,552,485		22,5
15	KGen Sandersville LLC	OS	T5						24,777		
16	Louisville Gas & Electric	OS	0				1,255		19,033		
17	Macquarie Energy, LLC	OS	T4				123,113		6,235,017		6,2
18	Mercuria Energy America, Inc	OS	T4				56,985		1,816,617		1,8
19	Midwest Independent Trans System	OS	T4				13,674		494,337		4
20	Morgan Stanley Capital Group, Inc.	OS	T4				8,776		363,715		3
21	Municipal Electric Authority Of Georgia	OS	T4				412,676	42,000	14,778,188		14,8
22	NextEra Gulf	OS	RS-138								
23	North Carolina EMC	OS	T4				5,934		159,928		1
24	NTE Carolinas	OS	T4				24		1,055		

25	Oglethorpe Power Corporation	OS	T4				8,629		296,915		2
26	Orlando Utilities Commission	OS	T4				2,754		111,476		1
27	PJM Interconnection	OS	T4				14,865		594,830		5
28	PowerSouth Energy Cooperative	OS	T4								
29	Rainbow Energy Marketing Corporation	OS	T4				43,357		1,710,744		1,7
30	Santa Rosa	OS	T5								
31	Seminole Electric Cooperative	OS	T4				430,988	4,310,164	12,334,876		16,6
32	South Carolina Electric & Gas Company	OS	T4						274,117		2
33	South Carolina Public Service Authority	OS	T4				615,798	7,420,557	15,885,588		23,3
34	South Mississippi Electric Power Association	OS	T4						39,043		
35	Southern Company Services	OS	RS-138				508,006	16,129,552	14,176,731		30,3
36	Southwest Power Pool, Inc	OS	T4								
37	Tampa Electric Company	OS	T4				32,076		1,703,457		1,7
38	Tennessee Valley Authority	OS	T4				926,243	75,415,374	37,046,281		112,4
39	The Energy Authority	OS	T4				153,712		5,100,200		5,1
40	Tri-County EMC	LU	T4				1,774		102,900		1
41	Washington County Power, LLC (Mackinaw Power)	OS	T5								
42	Westar Energy, Inc.	OS	T4								
43	Southeastern Power Administration	OS	T4				16,685		679,121		6
44	Walton Electric Membership Corporation	OS	T4				24,968	2,646,864	694,030		3,3

45	Entergy Services	OS	T4								
46	Jacksonville Electric Authority	OS	T4						1,061		
47	MAG Energy Solutions	OS	T4				312		15,241		
48	City of Hartford	OS	543						2,344		
49	MPC Generating, LLC	OS	T4						12,438		
15	Subtotal - RQ										
16	Subtotal-Non-RQ						4,618,241	151,921,997	139,808,869		291,7
17	Total						4,618,241	151,921,997	139,808,869		291,7

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	19,034,248	15,429,506
5	(501) Fuel	696,085,033	748,302,685
6	(502) Steam Expenses	23,163,255	26,517,436
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	19,607,014	17,473,063
10	(506) Miscellaneous Steam Power Expenses	48,952,653	45,010,448
11	(507) Rents		
12	(509) Allowances	15,883	18,535
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	806,858,086	852,751,673
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	9,500,646	11,016,298
16	(511) Maintenance of Structures	12,974,132	10,768,285
17	(512) Maintenance of Boiler Plant	66,063,953	57,573,787
18	(513) Maintenance of Electric Plant	12,426,655	9,974,878
19	(514) Maintenance of Miscellaneous Steam Plant	6,164,241	4,889,455
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	107,129,627	94,222,703
21	TOTAL Power Production Expenses-Steam Power (Enter Total of Lines 13 & 20)	913,987,713	946,974,376
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	134,156,387	102,754,490
25	(518) Fuel	158,704,631	144,301,898
26	(519) Coolants and Water	14,495,963	11,215,929
27	(520) Steam Expenses	19,609,780	15,322,228
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		

30	(523) Electric Expenses	619,183	102,444
31	(524) Miscellaneous Nuclear Power Expenses	175,546,340	132,657,925
32	(525) Rents	563,230	587,867
33	TOTAL Operation (Enter Total of lines 24 thru 32)	503,695,514	406,942,781
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	46,089,996	26,808,048
36	(529) Maintenance of Structures	3,911,616	3,626,312
37	(530) Maintenance of Reactor Plant Equipment	9,932,357	8,581,498
38	(531) Maintenance of Electric Plant	13,542,331	10,968,683
39	(532) Maintenance of Miscellaneous Nuclear Plant	29,004,392	23,405,535
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	102,480,692	73,390,076
41	TOTAL Power Production Expenses-Nuclear. Power (Enter Total of lines 33 & 40)	606,176,206	480,332,857
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	13,001,872	11,384,846
45	(536) Water for Power	2,051,091	1,907,526
46	(537) Hydraulic Expenses	5,370,316	3,337,436
47	(538) Electric Expenses	5,811,698	5,268,089
48	(539) Miscellaneous Hydraulic Power Generation Expenses	7,267,276	6,237,494
49	(540) Rents	51,634	50,573
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	33,553,887	28,185,964
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	6,819	19,617
54	(542) Maintenance of Structures	6,944,926	3,210,383
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,299,946	1,615,274
56	(544) Maintenance of Electric Plant	6,238,624	4,809,157
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,093,888	1,022,743
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	16,584,203	10,677,174
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 & 58)	50,138,090	38,863,138
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	9,506,478	9,083,028
63	(547) Fuel	802,833,774	888,871,830
64	(548) Generation Expenses	9,576,251	9,405,789

64.1	(548.1) Operation of Energy Storage Equipment		
65	(549) Miscellaneous Other Power Generation Expenses	30,374,673	23,171,667
66	(550) Rents	6,194	6,193
67	TOTAL Operation (Enter Total of Lines 62 thru 67)	852,297,370	930,538,507
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	4,605,959	5,287,071
70	(552) Maintenance of Structures	14,356,015	9,984,620
71	(553) Maintenance of Generating and Electric Plant	44,960,239	47,286,336
71.1	(553.1) Maintenance of Energy Storage Equipment		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,666,708	2,531,062
73	TOTAL Maintenance (Enter Total of Lines 69 thru 72)	66,588,921	65,089,089
74	TOTAL Power Production Expenses-Other Power (Enter Total of Lines 67 & 73)	918,886,291	995,627,596
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	1,391,308,243	1,314,344,529
76.1	(555.1) Power Purchased for Storage Operations	48,167	
77	(556) System Control and Load Dispatching	252,828	3,232,561
78	(557) Other Expenses	23,358,044	27,095,795
79	TOTAL Other Power Supply Exp (Enter Total of Lines 76 thru 78)	1,414,967,282	1,344,672,885
80	TOTAL Power Production Expenses (Total of Lines 21, 41, 59, 74 & 79)	3,904,155,582	3,806,470,852
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,187,259	5,851,805
85	(561.1) Load Dispatch-Reliability	6,576,688	6,474,378
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,297,320	7,051,466
87	(561.3) Load Dispatch-Transmission Service and Scheduling	430,018	362,718
88	(561.4) Scheduling, System Control and Dispatch Services	3,459,655	
89	(561.5) Reliability, Planning and Standards Development	1,797,793	4,964,002
90	(561.6) Transmission Service Studies	283,616	215,737
91	(561.7) Generation Interconnection Studies	566,524	496,526
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	6,400,949	7,219,637
93.1	(562.1) Operation of Energy Storage Equipment		
94	(563) Overhead Lines Expenses	1,590,235	841,839
95	(564) Underground Lines Expenses		

96	(565) Transmission of Electricity by Others	25,871,739	8,038,903
97	(566) Miscellaneous Transmission Expenses	24,587,718	21,044,694
98	(567) Rents	(7,933,973)	(47,968,913)
99	TOTAL Operation (Enter Total of Lines 83 thru 98)	76,115,541	14,592,792
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	15,745,484	14,306,185
102	(569) Maintenance of Structures	360,319	215,915
103	(569.1) Maintenance of Computer Hardware	5,187,387	11,162,038
104	(569.2) Maintenance of Computer Software	1,837,680	1,792,606
105	(569.3) Maintenance of Communication Equipment		(1)
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	18,221,614	13,437,252
107.1	(570.1) Maintenance of Energy Storage Equipment		
108	(571) Maintenance of Overhead Lines	51,482,471	23,865,864
109	(572) Maintenance of Underground Lines	42,858	(3,065)
110	(573) Maintenance of Miscellaneous Transmission Plant	32,993,627	825,994
111	TOTAL Maintenance (Total of Lines 101 thru 110)	125,871,440	65,602,788
112	TOTAL Transmission Expenses (Total of Lines 99 and 111)	201,986,981	80,195,580
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	26,020,967	21,846,425
135	(581) Load Dispatching	5,256,708	6,923,805
136	(582) Station Expenses	739,463	669,684
137	(583) Overhead Line Expenses	1,045,909	2,099,991
138	(584) Underground Line Expenses	17,526,101	15,794,163
138.1	(584.1) Operation of Energy Storage Equipment		
139	(585) Street Lighting and Signal System Expenses	13,029	269
140	(586) Meter Expenses	21,324,723	29,917,171
141	(587) Customer Installations Expenses	2,807,622	2,451,932
142	(588) Miscellaneous Expenses	51,495,956	45,702,847
143	(589) Rents	4,398,259	4,068,362
144	TOTAL Operation (Enter Total of Lines 134 thru 143)	130,628,737	129,474,649
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	13,784,043	13,795,482
147	(591) Maintenance of Structures	42,678	380,507
148	(592) Maintenance of Station Equipment	15,628,454	11,827,561
148.1	(592.2) Maintenance of Energy Storage Equipment		
149	(593) Maintenance of Overhead Lines	166,805,819	105,041,557
150	(594) Maintenance of Underground Lines	22,651,160	17,501,216
151	(595) Maintenance of Line Transformers	4,130,402	5,992,409
152	(596) Maintenance of Street Lighting and Signal Systems	14,723,107	19,403,006
153	(597) Maintenance of Meters	1,900,061	2,439,146
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of Lines 146 thru 154)	239,665,724	176,380,884
156	TOTAL Distribution Expenses (Total of Lines 144 and 155)	370,294,461	305,855,533
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,755,235	2,101,688
160	(902) Meter Reading Expenses	28,748,467	25,344,544
161	(903) Customer Records and Collection Expenses	109,380,848	119,409,224
162	(904) Uncollectible Accounts	50,924,263	25,995,512
163	(905) Miscellaneous Customer Accounts Expenses	11,346,396	8,951,322

164	TOTAL Customer Accounts Expenses (Enter Total of Lines 159 thru 163)	203,155,209	181,802,290
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	38,360	
168	(908) Customer Assistance Expenses	92,321,613	84,251,658
169	(909) Informational and Instructional Expenses	4,065	6,136
170	(910) Miscellaneous Customer Service and Informational Expenses	746,402	695,934
171	TOTAL Customer Service and Information Expenses (Total Lines 167 thru 170)	93,110,440	84,953,728
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	15,133	210,622
175	(912) Demonstrating and Selling Expenses	31,332,911	31,389,152
176	(913) Advertising Expenses	873,575	435,633
177	(916) Miscellaneous Sales Expenses	3,741,645	6,980,747
178	TOTAL Sales Expenses (Enter Total of Lines 174 thru 177)	35,963,264	39,016,154
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	74,753,505	73,616,201
182	(921) Office Supplies and Expenses	28,099,127	(36,844,628)
183	(Less) (922) Administrative Expenses Transferred-Credit	8,887,455	5,937,226
184	(923) Outside Services Employed	142,954,355	208,126,047
185	(924) Property Insurance	47,843,641	47,368,255
186	(925) Injuries and Damages	23,636,002	25,870,679
187	(926) Employee Pensions and Benefits	(72,186,444)	(50,484,167)
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	12,214,158	8,579,402
190	(929) (Less) Duplicate Charges-Cr.	13,482,909	6,354,593
191	(930.1) General Advertising Expenses	17,034,229	14,533,359
192	(930.2) Miscellaneous General Expenses	19,224,888	13,922,442
193	(931) Rents	5,242,508	5,111,194
194	TOTAL Operation (Enter Total of Lines 181 thru 193)	276,445,605	297,506,965
195	Maintenance		
196	(935) Maintenance of General Plant	18,593,723	18,040,787
197	TOTAL Administrative & General Expenses (Total of Lines 194 and 196)	295,039,328	315,547,752

198	TOTAL Electric Operation and Maintenance Expenses (Total of Lines 80, 112, 131, 156, 164, 171, 178, and 197)	5,103,705,265	4,813,841,889

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 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 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 pro 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 consume

   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 conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not b 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 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 fr 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

   EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settle

   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 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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the co 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 avera 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 demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60 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
6. Report in column (g) the megawatthours shown on bills rendered to the respondent, excluding purchases for energy storage. Report in column (h) the respondent for energy storage purchases. Report in columns (i) and (j) the megawatthours of power exchanges received and delivered, used as the b
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, the amount shown in column (m). Report in column (n) the total charge shown on bills received as settlement by the respondent. For power exchange net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (m) include credits or charges ot 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 Purc 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
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		
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)			MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	D Ch
1	Albany Renewable Energy, LLC	LU					381,436				10
2	ASI DG Group A Solar Contracts	(g) OS					64,817				
3	Associated Energy Cooperative Inc.	OS					675				

4	Augusta Canal Authority	LU					6,577				
5	Bird Dog Solar LLC	OS					91,496				
6	Birdsong Corporation	LU					805				
7	Blackwater Solar LLC	LU					94,206				
8	Bulldog Solar, LLC	LU					158,481				
9	CAC Contract	LU					623				
10	Chatsworth Water Works	LU					807				
11	City of Hartford	OS									
12	City of Jesup	LU					104				
13	City of Tallahassee, Florida	OS					1,518				
14	City of Troy, Alabama	OS									
15	Coca Cola	LU					38,889				
16	Constellation Energy	LU									
17	Conyers Renewable Power LLC	LU					18,121				
18	CPV Stagecoach Solar, LLC	LU					152,445				
19	Decatur Solar Energy Center, LLC	OS					161,838				
20	Dominion Energy	OS					2,318				
21	Dublin Solar I LLC	OS					4,144				
22	Duke Energy Carolinas, LLC	OS					14,174				
23	Duke Energy Florida LLC	LU					33,930				
24	Eagle Energy Partners I, L.P.	OS					15,390				
25	Enterprise Mill, LLC	LU					245				
26	Exelon Generation Company, LLC	OS					4,996				
27	Florida Power & Light Company	OS					5,195				
28	Graphic Packaging International	OS					4,793				

29	Green Energy	OS					670,817				
30	Green Power Solutions of Georgia LLC	LU					189,840				
31	GRP LLC	OS					766,721				
32	Hecate Energy Old Midville Rd, LLC	LU					42,202				
33	Hickory Park Solar LLC	LU					443,852				
34	Hobnail Solar, LLC	LU					151,679				
35	HSH Pembroke LLC	LU					1,677				
36	IKEA Atlanta	LU					34				
37	IKEA Savannah	LU					803				
38	International Paper Flint River	LU					165,179				4
39	International Paper Port Wentworth	LU					169,161				2
40	International Paper Qualified Facilities (QF)	OS					4,138				
41	Invenergy	LU					356,950				
42	KGen Sandersville LLC	OS									
43	Louisville Gas & Electric	OS					1,813				
44	Mackinaw Power LLC	LU					33,692				18
45	Macquarie Energy, LLC	OS					23,950				
46	MAG Energy Solutions	OS					1,750				
47	MARTA	LU					12				
48	MAS Georgia LFG LLC2	LU					129,675				
49	MCLB Albany (NAVFEC)	LU					22,275				
50	MEAG PSSA	OS					842,728				
51	Mercuria Energy America, Inc	LU					12,597				
52	Mid Georgia Cogen LP	OS					116,979				8
53	Midwest Independent Trans System	OS					20,178				
54	Mississippi Power Company	OS									59

55	Morgan Stanley Capital Group, Inc.	OS					27,872				
56	MPC Generating, LLC	OS									
57	Municipal Electric Authority Of Georgia	LU					228,761				3
58	NextEra Solar	OS					2,262,722				
59	North Carolina EMC	OS					1,189				
60	NTE Carolinas	SF					273				
61	Oglethorpe Power Corporation	LU					6,612				
62	Origis Energy	LU					573,810				
63	Packaging Corporation of America	LU					3,310				
64	Piedmont Green Power	LU					407,864				18
65	PJM Interconnection	OS					913				
66	Porsche Cars North America Inc	LU					960				
67	Rainbow Energy Marketing Corporation	OS					11,061				
68	Rayonier Inc	LU					119				
69	Richland Solar Center LLC	LU					41,325				
70	Rincon Solar I, LLC	LU					25,101				
71	Santa Rosa Energy Center LLC	OS					889,927				11
72	Simon Solar Farm	LU					47,674				
73	Solar Design & Development LLC	OS					1,166				
74	Solar Glynn, LLC	LU					15,868				
75	Sonny Solar, LLC	LU					88,148				
76	South Carolina Public Service Authority	OS					2,625				
77	[(a)] Southern Company Services	OS					16,023,440		16,912,213	16,991,768	1

78	[b] Southern Electric Generating Co	OS					708,064				9
79	[c] Southern Power Company	LU					2,921,680				88
80	Star Thread - Barnett Shoals Inc	LU					4,414				
81	Sustaining Power Solutions LLC	LU					717,171				
82	Tampa Electric Company	OS					12,833				
83	Tenaska Heard County Georgia	LU					22,541				43
84	Tennessee Valley Authority	OS					62,079				
85	The Energy Authority	OS					5,761				
86	Timberland Solar, LLC	LU					47,606				
87	Verizon Communications	OS					54				
88	Walton Electric Membership Corporation	OS					168,450				
89	Washington County Pwr	OS									4
90	WM Renewable Energy, LLC	OS					50,016				
91	Wolfskin Solar LLC	LU					10,181				
15	TOTAL						30,818,315		16,912,213	16,991,768	287

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Southern Company Services is a subsidiary of Southern Company.
(b) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Southern Electric Generating Company is 50% owned by each of Georgia Power and Alabama Power. Prior year amounts were included in totals reported for Southern Company Services.
(c) Concept: NameOfCompanyOrPublicAuthorityProvidingPurchasedPower
Southern Power Company is a subsidiary of Southern Company.
(d) Concept: StatisticalClassificationCode
OS-Unless indicated by FERC Rate Schedule Number, these are market-based purchases of non-firm energy from power marketing companies that have applications on file with the FERC.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1) (Including transactions referr

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-tr
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 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 acro 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 Netwo LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in p 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
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the subs specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as s
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in colum 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 revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills o 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 colur 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 F
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)	TRA Megawa Hours Receive (i)
1	SOUTHEASTERN POWER ADMINISTRATION	Southeastern Power Administration	Southeastern Power Administration	FNO	(t) 415	N/A	N/A	(z) 379	(ac) 649,7
2	TENNESSEE VALLEY AUTHORITY	Tennessee Valley Authority	Tennessee Valley Authority	FNO	(u) 160	N/A	N/A	125	722,2
3	POWERSOUTH ENERGY COOPERATIVE	PowerSouth Energy Cooperative	PowerSouth Energy Cooperative	FNO	225	N/A	N/A	716	4,132,3
4	ALABAMA MUNICIPAL ELECTRIC AUTHORITY	Alabama Muncipal Electric Authority	Alabama Muncipal Electric Authority	FNO	474	N/A	N/A	471	3,372,8
5	COOPERATIVE ENERGY	South Mississippi Electric Power Association	South Mississippi Electric Power Association	FNO	496	N/A	N/A	620	3,468,1
6	CITY OF TROY	CITY OF TROY	CITY OF TROY	FNO	473	N/A	N/A	62	467,6
7	CITY OF EVERGREEN	City of Evergreen	City of Evergreen	FNO	542	N/A	N/A	9	54,8
8	CITY OF HARTFORD	City of Hartford	City of Hartford	FNO	543	N/A	N/A	3	30,0
9	CITY OF ROBERTSDALE	City of Robertsdale	City of Robertsdale	FNO	544	N/A	N/A	14	91,7

10	FPL2014 - Exxon & Blackjack	FPL2014 - Exxon & Blackjack	FPL2014 - Exxon & Blackjack	FNO	700	N/A	N/A	9	82,2
11	GEORGIA TRANSMISSION CORP	GEORGIA TRANSMISSION CORP	GEORGIA TRANSMISSION CORP	FNO	720	N/A	N/A	3	10,7
12	EXELON GENERATION COMPANY, LLC	GTC	GTC	(g) LFP	TSA	SOCO	GTC	210	1,513,4
13	FLORIDA POWER & LIGHT COMPANY	FPLNW	FPLNW	(h) LFP	TSA	SOCO	FPLNW	124	1,013,0
14	FLORIDA POWER & LIGHT COMPANY	FPLNW	FPLNW	(i) LFP	TSA	SOCO	FPLNW	65	
15	JACKSONVILLE ELECTRIC AUTHORITY	JEA	JEA	(j) LFP	TSA	SOCO	JEA	61	
16	JACKSONVILLE ELECTRIC AUTHORITY	JEA	JEA	(k) LFP	TSA	SOCO	JEA	42	
17	JACKSONVILLE ELECTRIC AUTHORITY	JEA	JEA	(l) LFP	TSA	SOCO	JEA	103	1,432,2
18	MERCURIA ENERGY AMERICA, LLC	OPCLOAD	OPCLOAD	(m) LFP	TSA	SOCO	GTC	220	1,375,4
19	North Carolina Electric Membership Corporation	DUK	DUK	(n) LFP	TSA	SOCO	DUK	44	11,8
20	POWERSOUTH ENERGY COOPERATIVE	FPLNW	FPLNW	(o) LFP	TSA	SOCO	FPLNW	144	620,8
21	SEMINOLE ELECTRIC COOPERATIVE INCORPORATED	FPC	FPC	(p) LFP	TSA	SOCO	FPC	100	466,0
22	SANTEE COOPER	SCBP	SCBP	(q) LFP	TSA	SOCO	SCBP	400	3,310,8
23	FLORIDA POWER & LIGHT COMPANY	FPLNW	FPLNW	(r) LFP	TSA	SOCO	FPLNW	210	549,1
24	TENNESSEE VALLEY AUTHORITY	TVA	TVA	(s) LFP	TSA	SOCO	TVA	1,000	1,823,7
25	(a) VARIOUS Non Firm Customers	(c) VARIOUS Non Firm Customers	(e) VARIOUS	NF	TSA	(v) VARIOUS	(x) VARIOUS	(aa) 0	(ae) 205,8
26	(b) VARIOUS Short Term Firm Customers	(d) VARIOUS Short Term Firm Customers	(f) VARIOUS	SFP	TSA	(w) VARIOUS	(y) VARIOUS	(ab) 0	1,784,3
27	VARIOUS Tariff Customers	VARIOUS Tariff Customers	VARIOUS	AD	TSA	VARIOUS	VARIOUS	0	
28	VARIOUS Tariff Customers	VARIOUS Tariff Customers	VARIOUS	OS	TSA	VARIOUS	VARIOUS	0	4,296,2
35	TOTAL							5,134	31,485,8

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PaymentByCompanyOrPublicAuthority

Various Non-Firm Point-to-Point Transmission Service customers under the Southern Companies' Open Access Transmission Tariff.

(b) Concept: PaymentByCompanyOrPublicAuthority

Various Short-Term Firm Point-to-Point Transmission Service customers under the Tariff

(c) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Various entities pursuant to the terms and conditions of the Tariff

(d) Concept: TransmissionEnergyReceivedFromCompanyOrPublicAuthorityName

Various entities pursuant to the terms and conditions of the Tariff

(e) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Various entities pursuant to the terms and conditions of the Tariff

(f) Concept: TransmissionEnergyDeliveredToCompanyOrPublicAuthorityName

Various entities pursuant to the terms and conditions of the Tariff

(g) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(h) Concept: StatisticalClassificationCode

Termination Date: January 1, 2036

(i) Concept: StatisticalClassificationCode

Termination Date: January 1, 2036

(j) Concept: StatisticalClassificationCode

Termination Date: January 1, 2036

(k) Concept: StatisticalClassificationCode

Termination Date: January 1, 2036

(l) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(m) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(n) Concept: StatisticalClassificationCode

Termination Date: June 1, 2025

(o) Concept: StatisticalClassificationCode

Termination Date: May 1, 2027

(p) Concept: StatisticalClassificationCode

Termination Date: January 1, 2027

(q) Concept: StatisticalClassificationCode

Termination Date: January 1, 2029

(r) Concept: StatisticalClassificationCode

Termination Date: June 1, 2024

(s) Concept: StatisticalClassificationCode

Termination Date: June 1, 2024

(t) Concept: RateScheduleTariffNumber

FERC Rate Schedule 415, Agreement for Network Integration Transmission Service and Complementary Services. FERC Electric Tariff Fourth Revised Volume No. 5, the Southern Company electric operating companies (Alabama Power Company, Georgia Power Company, and Mississippi Power Company) Open Access Transmission tariff (the "Tariff"). The Southern Company electric operating companies collectively are the Transmission Provider under the Tariff and operate their transmission facilities as a single integrated system.

(u) Concept: RateScheduleTariffNumber

Line Nos. 2-26 Column: e
FERC Electric Tariff Fourth Revised Volume No. 5, the "Tariff."

(v) Concept: TransmissionPointOfReceipt

Various points of receipt.

(w) Concept: TransmissionPointOfReceipt

Various points of receipt.

(x) Concept: TransmissionPointOfDelivery

Various points of delivery.

(y) Concept: TransmissionPointOfDelivery

Various points of delivery.

(z) Concept: BillingDemand

Line Nos. 1-11 Column: h
The billing demand is based on a rolling 12 month average of the Transmission Customer's load under the Tariff coincident with the Transmission Provider's monthly transmission peak load. The demand reported in column h is the most recent 12 month average load for the quarter.

(aa) Concept: BillingDemand

Various - Total billing demand varies based on the duration of service (e.g. hourly, daily, weekly, or monthly.

(ab) Concept: BillingDemand

Various - Total billing demand varies based on the duration of service (e.g. daily, weekly, or monthly).

(ac) Concept: TransmissionOfElectricityForOthersEnergyReceived

Line Nos. 1-11 Column: i
Total MWH received by the Southern Company electric operating companies for Network Integration Transmission Service.

(ad) Concept: TransmissionOfElectricityForOthersEnergyReceived

Line Nos. 12-24 Column: i
Total MWH received by Southern Company electric operating companies for Long-Term Firm Point-to-Point Transmission Service .

(ae) Concept: TransmissionOfElectricityForOthersEnergyReceived

Total MWH received by Southern Company electric operating companies for Non-Firm Point-to-Point Transmission Service.

(af) Concept: TransmissionOfElectricityForOthersEnergyReceived

Total MWH received by Southern Company electric operating companies for Short-Term Firm Point-to-Point Transmission Service.

(ag) Concept: TransmissionOfElectricityForOthersEnergyReceived

OS: OS consists of recallable contracts. Billing demand is not reported because these types of contracts are excluded from the tariff rate load calculation. MWH Delivered and Received

(ah) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Line Nos. 1-11 Column j
Total MWH delivered by the Southern Company electric operating companies for Network Integration Transmission Service.

(ai) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Line Nos. 12-24 Column: j
Total MWH delivered by Southern Company electric operating companies for Long-Term Firm Point-to-Point Transmission Service .

(aj) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Total MWH delivered by the Southern Company electric operating companies for Non-Firm Point-to-Point Transmission Service.

(ak) Concept: TransmissionOfElectricityForOthersEnergyDelivered

Total MWH delievered by Southern Company electric operating companies for Short-Term Firm Point-to-Point Transmission Service.

(al) Concept: TransmissionOfElectricityForOthersEnergyDelivered

OS: OS consists of recallable contracts. Billing demand is not reported because these types of contracts are excluded from the tariff rate load calculation. MWH Delivered and Received

(am) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

Line Nos. 1-27 Column k,l,m,n
Amount of charges allocated to the respondent.

(an) Concept: DemandChargesRevenueTransmissionOfElectricityForOthers

OS: OS consists of recallable contracts. Billing demand is not reported because these types of contracts are excluded from the tariff rate load calculation. Demand and Other Dollars

(ao) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers

Line Nos. 1-27 Column k,l,m,n
Amount of charges allocated to the respondent.

(ap) Concept: EnergyChargesRevenueTransmissionOfElectricityForOthers

Line Nos. 1 -26, 28 Columns: m
The Southern Company electric operating companies' Charge for Recovery of the FERC Annual and Attachment K Charges.

(aq) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Line Nos. 1-27 Column k,l,m,n
Amount of charges allocated to the respondent.

(ar) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers

Various Long-Term Firm, Conditional Long-Term Firm and Network Integration Transmission Service Customers that purchased service during January 2023 through December 2023, and will receive OATT Tariff True-Up refunds. This also includes the 2024 Penalty Payout for all non-offenders

(as) Concept: OtherChargesRevenueTransmissionOfElectricityForOthers
OS: OS consists of recallable contracts. Billing demand is not reported because these types of contracts are excluded from the tariff rate load calculation. Demand and Other Dollars
(at) Concept: RevenuesFromTransmissionOfElectricityForOthers
Line Nos. 1-27 Column k,l,m,n ***Amount of charges allocated to the respondent.***

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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					
16					
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44					
45					
46					
47					
48					
49					
40	TOTAL				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	OS	22,921				60,047	60,047
2	Florida Power & Light Company	OS	22				208	208
3	Southern Power (EMC 11)	OS	725,691				143,484	143,484
4	Southern Company Services (Self-Use)	OS	4,241,023				25,154,054	25,154,054
5	Tennessee Valley Authority	OS	642				494,024	494,024
6	Georgia Transmission Corp	OS	2,702					
7	Municipal Electric Authority of Ga (MEAG)	OS					403	403
8	MISO	OS	22,188				23,182	23,182
9	Rainbow Energy Mktng Corp	OS					(5,119)	(5,119)
10	Dominion Energy	OS					519	519
11	SC Public Service Authority	OS					937	937
	TOTAL		5,015,189				25,871,739	25,871,739

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,136,830
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	890,328
4	Pub and Dist Info to Stkhldrs...expn servicing outstanding Securities	1,623,996
5	Oth Expn greater than or equal to 5,000 show purpose, recipient, amount. Group if less than $5,000	
6	Directors' Fees and Expenses	5,629,462
7	Substance Abuse Testing	117,465
8	Community Development	720,554
9	Agent Fees	3,913,185
10	DOE Loan Guarantee Fees and Compliance Cost	444,103
11	Contract Retention	2,908,868
12	Misc Labor Expense	223,607
13	Miscellaneous General Expenses	1,616,490
46	TOTAL	19,224,888

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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			63,559,610		63,559,610
2	Steam Production Plant	398,206,241	19,216,417			417,422,658
3	Nuclear Production Plant	191,912,437	5,940,839			197,853,276
4	Hydraulic Production Plant-Conventional	21,961,284	261,339			22,222,623
5	Hydraulic Production Plant-Pumped Storage	8,767,868				8,767,868
6	Other Production Plant	180,112,330	1,903,243			182,015,573
7	Transmission Plant	197,410,354	(36,240)			197,374,114
8	Distribution Plant	461,731,516	(15,273)			461,716,243
9	Regional Transmission and Market Operation					
10	General Plant	49,340,151	(192,627)			49,147,524
11	Common Plant-Electric					
12	TOTAL	[a]1,509,442,181	27,077,698	63,559,610		1,600,079,489

B. Basis for Amortization Charges

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	Steam	7,807.223	70 years	(20)	7.24	VARIOUS	9 years, 5 months
13	Nuclear	7,594.11	69 years	(25)	1.8	VARIOUS	38 years, 9 months

14	Hydraulic	926.179	90 years	(30)	3.08	VARIOUS	20 years, 4 months
15	Other	3,797.624	42 years	(4)	5.12	VARIOUS	25 years, 6 months
16	Transmission						
17	350	452.898	120 years	0	0.52	S6	111 years, 11 months
18	352	301.395	100 years	(30)	1.34	R2	88 years, 4 months
19	353	3,079.178	53 years	(30)	2.57	L0.5	44 years, 6 months
20	354	1,246.397	68 years	(30)	2.04	R2	52 years, 10 months
21	355	867.45	54 years	(30)	2.52	R0.5	45 years
22	356	1,919.817	50 years	(30)	2.85	R3	35 years, 9 months
23	357	11.852	80 years	(30)	1.73	R5	63 years, 3 months
24	358	24.454	55 years	(30)	2.48	R2	45 years, 9 months
25	359	16.01	70 years	(30)	1.88	SQ	66 years
26	Transmission Total	7,919.451	72 years		2.44		61 years, 6 months
27	Distribution						
28	360	262.472	100 years	0	1	S6	94 years
29	361	332.431	85 years	(25)	1.45	R1.5	75 years, 1 month
30	362	2,098.748	47 years	(25)	2.6	R0.5	39 years, 5 months
31	364	1,480.997	47 years	(25)	2.59	L0	38 years
32	365	1,797.29	40 years	(25)	3.04	L0	32 years, 5 months
33	366	621.303	80 years	(25)	1.51	S6	60 years, 9 months
34	367	2,965.199	51 years	(25)	2.39	R0.5	41 years, 7 months
35	368	2,075.903	38 years	(25)	3.16	R0.5	28 years, 2 months
36	369	1,262.609	51 years	(25)	2.35	R1	37 years, 4 months
37	370	561.174	18 years	(25)	6.6	R0.5	12 years, 7 months
38	371	20.397	10 years	0	9.64	SQ	7 years, 8 months
39	372	0.798	10 years	0	0	SQ	
40	373	1,101.106	23 years	(25)	5.21	R0.5	16 years, 11 months
41	Distribution Total	14,580.427	49 years		2.9		37 years, 3 months
42	General						
43	390	807.005	65 years	0	1.28	R0.5	55 years, 10 months
44	392	426.849	8 years	20	4.06	VARIOUS	5 years, 7 months
45	396	42.3	7 years	20	8.02	L0	5 years, 3 months
46	397	537.447	20 years	0	2.72	L0	20 years, 3 months
47	General Total	1,813.601	25 years		2.65		21 years, 9 months

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: DepreciationExpenseExcludingAmortizationOfAcquisitionAdjustments

The depreciable base is calculated as an average of beginning and ending plant in service balances.
2) The average remaining service life is presented as of the measurement date used in the study to compute the depreciation rates used in the current year.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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) rela 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 previc
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	
						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 (b) + (c) (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)	Am
1	VOGTLE 3 & 4 CONSTRUCTION MONITORING - DOCKET NO. 29849		857,404	857,404		ELECTRIC	107	857,404			
2	FUEL COST RECOVERY - DOCKET NO. 22403 and 44902		19,158	19,158		ELECTRIC	928	19,158			
3	RENEWABLES AND GREEN ENERGY - DOCKET NO. 43107		92	92		ELECTRIC	928	92			
4	INTEGRATED RESOURCE PLAN - DOCKET NOS. 42641, 42310, 45084, 44160, and 55378		2,832,142	2,832,142		ELECTRIC	928	2,832,142			
5	DEMAND SIDE MANAGEMENT CERTIFICATION - DOCKET NOS.43040, and 44161		148,263	148,263		ELECTRIC	928	148,263			
6	ALTERNATIVE RATE PLAN - DOCKET NOs. 36989, 42516, 43083, and 44280		330,103	330,103		ELECTRIC	928	330,103			
7	SAWNEE EMC v. GPC DOCKET NO. 43899		44,699	44,699		ELECTRIC	928	44,699			
8	ALL SOURCE RFP DOCKET NO. 55268		302,675	302,675		ELECTRIC	928	302,675			

9	2025 IRP DOCKET NO. 56002		1,079,568	1,079,568		ELECTRIC	928	1,079,568			
10	YATES CONSTRUCTION MONITORING DOCKET NO. 55931		44,110	44,110		ELECTRIC	107	44,110			
11	DOCKET ITEMS UNDER $25,000 (7 ITEMS): (APPLICATION FEES, LEGAL AND PROFESSIONAL SERVICES)		54,990	54,990		ELECTRIC	928	54,990			
12						0	0				
46	TOTAL		5,713,204	5,713,204				5,713,204			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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:

   Electric R, D and D Performed Internally:

   Generation

   hydroelectric

   Recreation fish and wildlife
   Other hydroelectric

   Fossil-fuel steam
   Internal combustion or gas turbine
   Nuclear
   Unconventional generation
   Siting and heat rejection

   Transmission

   Overhead
   Underground
   Distribution
   Regional Transmission and Market Operation
   Environment (other than equipment)
   Other (Classify and include items in excess of $50,000.)
   Total Cost Incurred

   Electric, R, D and D Performed Externally:

   Research Support to the electrical Research Council or the Electric Power Research Institute
   Research Support to Edison Electric Institute
   Research Support to Nuclear Power Groups
   Research Support to Others (Classify)
   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		Unamortized Accumulation (g)
					Amounts Charged In Current Year: Account (e)	Amounts Charged In Current Year: Amount (f)	
1	A. ELECTRIC UTILITY R,D&D PERFORMED INTERNALLY						
2	(1) GENERATION						
3	b. Fossil-fuel steam	Advanced Power Plant 506	2,164,619		506	449,180	
4		Advanced Power Plant 539			539	86,733	
5		Advanced Power Plant 549			549	1,628,706	
6	d. Nuclear	Advanced Nuclear 524	2,576,021		524	2,576,021	
7	e. Unconventional Generation	Renewable, Storage, Distributed Generation 506	845,387		506	419,073	

8		Renewable, Storage, Distributed Generation 539			539	57,881	
9		Renewable, Storage, Distributed Generation 549			549	368,433	
10	(2) TRANSMISSION						
11	a. Overhead	Power Delivery Transmission Research 566	1,582,905		566	1,582,905	
12	(3) DISTRIBUTION	Power Delivery Distribution Research 588	396,119		588	396,119	
13	(5) ENVIRONMENTAL	Advanced End Use Technology 930.2	1,921		930.2	1,921	
14		Advanced Energy Systems 506	2,770,820		506	1,474,392	
15		Advanced Energy Systems 549			549	1,296,428	
16		Environmental Controls Technologies 506	833,069		506	543,420	
17		Environmental Controls Technologies 549			549	289,649	
18	(6) OTHER	Research Administration 506	1,748,207		506	853,703	
19		Research Administration 539			539	120,290	
20		Research Administration 549			549	761,266	
21		Research Administration 566			566	1,552	
22		Research Administration 588			588	11,396	
23	B. ELECTRIC UTILITY R,D&D PERFORMED EXTERNALLY						
24	(1) RESEARCH SUPPORT TO THE ELECTRIC						
25	POWER RESEARCH INSTITUTE	Electric Power Research Institute 506		8,322,157	506	1,403,053	
26		Electric Power Research Institute 517			517	289,996	
27		Electric Power Research Institute 524			524	2,230,409	
28		Electric Power Research Institute 539			539	114,968	
29		Electric Power Research Institute 549			549	1,030,321	
30		Electric Power Research Institute 566			566	1,940,428	
31		Electric Power Research Institute 588			588	585,826	

32		Electric Power Research Institute 910			910	727,156	
33	LESS COST BILLED TO OTHERS			(610,119)	506, 566	(610,119)	
34	TOTAL COMPANY COST		12,919,068	7,712,038		20,631,106	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	95,424,300		
4	Transmission	16,007,954		
5	Regional Market			
6	Distribution	62,440,007		
7	Customer Accounts	47,328,473		
8	Customer Service and Informational	11,772,015		
9	Sales	19,054,621		
10	Administrative and General	74,629,529		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	326,656,899		
12	Maintenance			
13	Production	30,489,703		
14	Transmission	26,482,692		
15	Regional Market			
16	Distribution	60,973,974		
17	Administrative and General	2,401,849		
18	TOTAL Maintenance (Total of lines 13 thru 17)	120,348,218		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	125,914,003		
21	Transmission (Enter Total of lines 4 and 14)	42,490,646		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	123,413,981		
24	Customer Accounts (Transcribe from line 7)	47,328,473		
25	Customer Service and Informational (Transcribe from line 8)	11,772,015		
26	Sales (Transcribe from line 9)	19,054,621		
27	Administrative and General (Enter Total of lines 10 and 17)	77,031,378		

28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	447,005,117	6,330,030	453,335,147
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			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
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			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
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)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			

62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	447,005,117	6,330,030	453,335,147
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	383,587,520	21,745,803	405,333,323
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	383,587,520	21,745,803	405,333,323
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Other Accounts (Specify, provide details in footnote):			
79	Accounts Receivable	45,891,232	309,257	46,200,489
80	Office Building	1,626,074		1,626,074
81	Printing and Reproduction	407,316		407,316
82	Tool Clearing	90,507		90,507
83	General Shops Expenses	3,050,948		3,050,948
84	Other Clearing Accounts	(7,077)		(7,077)
85	Jobbing Work in Progress	2,238,161		2,238,161
86	Other Non-Operating Expenses	27,600,058	1,907,122	29,507,180
87	All Other General Accounts	13,026,795		13,026,795
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	93,924,014	2,216,379	96,140,393
96	TOTAL SALARIES AND WAGES	924,516,651	30,292,212	954,808,863

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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)	[a]864,592	902,859	956,628	873,143
2.1	Net Purchases (Account 555.1)				
3	Net Sales (Account 447)	(411,033)	(777,333)	(977,923)	(1,162,805)
4	Transmission Rights	194,964	317,349	403,442	508,963
5	Ancillary Services	219	345	393	393
6	Other Items (list separately)				
7	Balancing Operating Reserve	3,797	4,263	5,576	7,744
8	Administrative Fees	2,791	16,618	17,276	18,255
9	Miscellaneous	6	38	32	5
46	TOTAL	655,336	464,139	405,424	[b]245,698

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: IsoOrRtoSettlementsEnergyNetPurchasesPurchasedPower

Line Nos. 1-9 Columns: b-e

These amounts represent Georgia Power's portion of the RTO settlement statements received by Southern Company Services. RTO settlement statements received by Southern Company Services include amounts allocated to Alabama Power, Georgia Power, Mississippi Power, and Southern Power Company.

(b) Concept: IsoOrRtoSettlements

The amounts presented agree with settlement statements received and do not include adjustments from other periods that might have been booked.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	0	—	[a]0	102,003	MW-Months	8,221,197
2	Reactive Supply and Voltage	6,609	MWhs	727,000	53,657	MW-Months	5,901,175
3	Regulation and Frequency Response	0	—	0	18,380	MW-Months	887,683
4	Energy Imbalance	21,299	MWhs	749,971	9,565	MWhs	333,315
5	Operating Reserve - Spinning	0	—	0	15,793	MW-Months	1,326,467
6	Operating Reserve - Supplement	0	—	0	15,793	MW-Months	1,326,467
7	Other	[b]23681	MWhs	765,878	16,000	MWhs	678,838
8	Total (Lines 1 thru 7)	51,589		2,242,849	231,191		18,675,142

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: AncillaryServicesPurchasedAmount

Line No. 1-6 column: d, g

The Southern Company electric operating companies (Alabama Power Company, Georgia Power Company, and Mississippi Power Company) collectively are the Transmission Provider under the Open Access Transmission Tariff (OATT) and operate their transmission facilities as a single integrated system. The ancillary services, sales, and purchase amounts associated with transmission service provided under the OATT are the total values for the Southern Company electric operating companies.

(b) Concept: AncillaryServicesPurchasedNumberOfUnits

Line No. 7 column: b,d,e,g

Generator Imbalance Service (Schedule 10) offered under the OATT.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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: Georgia Power Company									
1	January	[a]35,458	17	8	167	530	1,251		1,667	31,843
2	February	26,606	1	7	97	364	1,251		869	24,025
3	March	24,153	19	8	89	425	1,251		514	21,874
4	Total for Quarter 1				353	1,319	3,753		3,050	77,742
5	April	24,083	19	17	49	378	1,251		442	21,963
6	May	28,006	28	16	78	566	1,251		473	25,638
7	June	32,803	26	16	75	571	2,251		88	29,818
8	Total for Quarter 2				202	1,515	4,753		1,003	77,419
9	July	32,166	8	16	95	447	2,251		238	29,135
10	August	32,733	1	16	96	499	2,251			29,887
11	September	30,573	23	16	81	454	2,251		170	27,617
12	Total for Quarter 3				272	1,400	6,753		408	86,639
13	October	26,821	7	16	60	746	2,251		96	23,668
14	November	23,706	30	8	105	347	2,251		195	20,808
15	December	29,685	4	7	111	288	2,251		275	26,760
16	Total for Quarter 4				276	1,381	6,753		566	71,236
17	Total				1,103	5,615	22,012		5,027	313,036

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: MonthlyPeakLoadExcludingIsoAndRto

The Southern Company electric operating companies (Alabama Power Company, Georgia Power Company, and Mississippi Power Company) collectively are the Transmission Provider under the Open Access Transmission Tariff and operate their transmission facilities as a single integrated system. Values shown correspond to the total transmission system peak loads on the Southern Company transmission system. Estimated load values are shown. The estimated loads are based on the customer's peak demand for previous month. Values are also based on telemetered load values using preliminary peak day and hour. The peak day and hour could change when actual loads are available.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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: Enter System									
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 2025-04-03	Year/Period of Report End of: 2024/ Q4

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)	87,225,926
3	Steam	14,515,470	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	22,671,135	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,618,241
5	Hydro-Conventional	1,280,406	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	289,589	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	132,415
7	Other	26,668,962	27	Total Energy Losses	3,817,809
8	Less Energy for Pumping	369,931	27.1	Total Energy Stored	
9	Net Generation (Enter Total of lines 3 through 8)	65,055,631	28	TOTAL (Enter Total of Lines 22 Through 27.1) MUST EQUAL LINE 20 UNDER SOURCES	95,794,391
10	Purchases (other than for Energy Storage)	30,818,315			
10.1	Purchases for Energy Storage				
11	Power Exchanges:				
12	Received	16,912,213			
13	Delivered	16,991,768			
14	Net Exchanges (Line 12 minus line 13)	(79,555)			
15	Transmission For Other (Wheeling)				
16	Received	31,485,814			
17	Delivered	30,918,195			
18	Net Transmission for Other (Line 16 minus line 17)	567,619			
19	Transmission By Others Losses	(567,619)			
20	TOTAL (Enter Total of Lines 9, 10, 10.1, 14, 18 and 19)	95,794,391			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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: Georgia Power Company					
29	January	8,512,265	338,282	16,458	17	6
30	February	7,011,861	228,046	13,238	1	6
31	March	6,782,224	139,826	11,883	19	7
32	April	7,025,862	452,610	12,655	19	15
33	May	7,877,011	286,811	13,940	23	15
34	June	8,925,274	280,900	16,555	26	15
35	July	9,527,039	433,419	16,137	15	13
36	August	9,594,693	523,618	16,430	29	15
37	September	7,769,097	351,361	15,291	23	14
38	October	7,213,488	275,428	13,036	7	14
39	November	7,226,034	528,007	11,232	8	14
40	December	8,329,543	779,933	14,774	4	6
41	Total	95,794,391	4,618,241			

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 Mcf.
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: BOWEN	Plant Name: FORT BENNING	Plant Name: FORT GORDON	Plant Name: FORT STEWART	Plant Name: FORT VALLEY STATE UNIVERSITY	Plant Name: [(a) (b)] HATCH	Plant Name: KING'S BAY	Plant Name: MCDONOUGH NO. 3
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	STEAM	SOLAR PROJECT	SOLAR PROJECT	SOLAR PROJECT	SOLAR PROJECT	NUCLEAR	SOLAR PROJECT	COMBUSTION TURBINE
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL	OUTDOOR	OUTDOOR	OUTDOOR	OUTDOOR	0	OUTDOOR	(PEAK LOAD) INDOOR
3	Year Originally Constructed	1971	2015	2016	2016	2022	1974	2016	1971
4	Year Last Unit was Installed	1975	2015	2016	2016	2022	1978	2016	1971
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	3,499.00	30.01	30.00	30.00	10.80	926.00	30.16	84.00
6	Net Peak Demand on Plant - MW (60 minutes)	3,129	30	40	26	11	908	30	76
7	Plant Hours Connected to Load	8,701	3,999	3,782	3,130	3,817	8,776	3,968	12
8	Net Continuous Plant Capability (Megawatts)	0	30	30	30	11	0	30	0

9	When Not Limited by Condenser Water	3,120	0	0	0	0	881	0	64
10	When Limited by Condenser Water	0	0	0	0	0	0	0	0
11	Average Number of Employees	425	0	0	0	0	920	0	0
12	Net Generation, Exclusive of Plant Use - kWh	10,708,428,000	51,471,000	43,959,000	35,247,000	21,145,000	7,066,128,048	49,092,000	104,000
13	Cost of Plant: Land and Land Rights	28,154,306					599,935		
14	Structures and Improvements	546,525,651	4,336,961	32,010	4,273,198	1,533,942	202,078,470	32,758	788,855
15	Equipment Costs	4,621,125,549	62,960,515	67,134,439	62,952,979	21,366,797	1,189,125,645	67,602,611	25,107,667
16	Asset Retirement Costs	563,065,634	4,296,554	3,814,082	4,533,258	3,070,274	(46,929,843)	4,113,404	
17	Total cost (total 13 thru 20)	5,758,871,140	71,594,030	70,980,532	71,759,434	25,971,013	1,344,874,207	71,748,772	25,896,521
18	Cost per KW of Installed Capacity (line 17/5) Including	1,645.8620	2,385.6724	2,366.0177	2,391.9811	2,404.7234	1,452.3480	2,378.9381	308.2919
19	Production Expenses: Oper, Supv, & Engr	12,990,052	96,927	96,911	96,911	34,475	46,996,168	98,518	28,493
20	Fuel	546,218,469					19,568,474		54,301
21	Coolants and Water (Nuclear Plants Only)						5,172,505		
22	Steam Expenses	21,253,549	51,342	32,341	61,806	22,108	8,672,743	(37,412)	
23	Steam From Other Sources								
24	Steam Transferred (Cr)								
25	Electric Expenses	13,107,209					5,808		
26	Misc Steam (or Nuclear) Power Expenses	13,092,853	62,239	60,834	40,118	20,688	58,424,361	52,447	51,487
27	Rents						234,449		

28	Allowances	7,949							
29	Maintenance Supervision and Engineering	4,365,572					13,472,820		(8)
30	Maintenance of Structures	6,664,963	1,288	8,211	51,832	35	1,513,769	98	2,127
31	Maintenance of Boiler (or reactor) Plant	48,077,721					2,749,780		
32	Maintenance of Electric Plant	8,671,345	428,390	284,279	416,567	132,419	6,456,633	341,995	
33	Maintenance of Misc Steam (or Nuclear) Plant	3,903,949	39,742	54,676	41,986	6,290	11,121,222	47,427	
34	Total Production Expenses	678,353,631	679,928	537,252	709,220	216,015	174,388,732	503,073	136,400
35	Expenses per Net kWh	0.0633	0.0132	0.0122	0.0201	0.0102	0.0247	0.0102	1.3115

35	**Plant Name**	BOWEN	BOWEN	HATCH	MCDONOUGH NO. 3	MCDONOUGH NO. 3	MCDONOUGH NO. 4-6	MCDONOUGH NO. 4-6	MCINTOSH (CC)	MCINT (CT)
36	Fuel Kind	Coal	Oil	Nuclear	Gas	OIl	Gas	Oil	Gas	Gas
37	Fuel Unit	T	bbl	g	Mcf	bbl	Mcf	bbl	Mcf	Mcf
38	Quantity (Units) of Fuel Burned	4,472,162	30,437	1,176,181	0	2,188	121,272,150		54,544,366	475
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11,860	6	64,643,371	0	6	1,034		1,033	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	120.577	129.279	43.950		133.343	3.619		3.125	
41	Average Cost of Fuel per Unit Burned	120.577	129.279	43.950		133.343	3.619		3.125	
42	Average Cost of Fuel Burned per Million BTU	5.083	22.224	0.680		22.922	3.501		3.026	
43	Average Cost of Fuel Burned per kWh Net Gen	0.050		0.007			0.024		0.021	
44	Average BTU per kWh Net Generation	9,902.477		10,760.106			6,969.971		7,011.170	15,347

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Plant Vogtle and Plant Hatch, are jointly owned with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton.

(b) Concept: PlantName

After nuclear fuel is placed in the reactor, the cost of fuel is amortized on the basis of quantity of heat produced, therefore matching the cost of the fuel with the power produced.

b) Uranium: lbs
Conversion: Kilograms of uranium (kgU)
Enrichment: Separative work units (SWU)
Fabrication: Assemblies

c) Type of fuel Used: Uranium
Enrichment: 4-5%
Fuel Array: 10 x 10
Fuel Assemblies: 560 Assemblies per Unit
Active Length of Fuel Assembly: Approximately 12.5 feet
Fuel Rods per Assembly: 96
Reactors: Two Boiling Water Reactors (BWRs) manufactured by General Electric Company

(c) Concept: PlantName

Plant Scherer is jointly owned with Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, the City of Dalton, Florida Power and Light Company, and Jacksonville Electric Authority.

(d) Concept: PlantName

After nuclear fuel is placed in the reactor, the cost of fuel is amortized on the basis of quantity of heat produced, therefore matching the cost of the fuel with the power produced.

b) Uranium: lbs
Conversion: Kilograms of uranium (kgU)
Enrichment: Separative work units (SWU)
Fabrication: Assemblies

c) Type of fuel Used: Uranium
Enrichment: 4-5%
Fuel Array: 17 x 17
Fuel Assemblies: 193 Assemblies per Unit
Active Length of Fuel Assembly: Approximately 12 feet
Fuel Rods per Assembly: 264
Reactors: Two Pressurized Water Reactors (PWRs) manufactured by Westinghouse Electric Company

(e) Concept: PlantName

After nuclear fuel is placed in the reactor, the cost of fuel is amortized on the basis of quantity of heat produced, therefore matching the cost of the fuel with the power produced.

b) Uranium: lbs
Conversion: Kilograms of uranium (kgU)
Enrichment: Separative work units (SWU)
Fabrication: Assemblies

c) Type of fuel Used: Uranium
Enrichment: 4-5%
Fuel Array: 17 x 17
Fuel Assemblies: 157 Assemblies per unit
Active Fuel Length of Assembly: Approximately 14 feet
Fuel Rods per Assembly: 264
Reactors: Two Pressurized Water Reactors (PWRs) manufactured by Westinghouse Electric Company

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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. 1951 Plant Name: SINCLAIR DAM	FERC Licensed Project No. 2177 Plant Name: GOAT ROCK	FERC Licensed Project No. 2177 Plant Name: NORTH HIGHLANDS	FERC Licensed Project No. 2177 Plant Name: OLIVER DAM	FERC Licensed Project No. 2237 Plant Name: MORGAN FALLS	FERC Licensed Project No. 2336 Plant Name: LLOYD SHOALS	FERC Licensed Project No. 2354 Plant Name: MATHIS-TERRORA	Li Pr Pla TA
1	Kind of Plant (Run-of-River or Storage)		Storage	Run-of-River	Run-of-River	Run-of-River	Run-of-River	Storage	Storage	Ru
2	Plant Construction type (Conventional or Outdoor)		Conventional	Conventional	Conventional	Conventional	Conventional	Conventional	Conventional	Cor
3	Year Originally Constructed		1953	1912	1963	1959	1903	1911	1925	
4	Year Last Unit was Installed		1953	2005	1963	1959	1923	1916	1925	
5	Total installed cap (Gen name plate Rating in MW)		45	39	29.6	60	16.8	14.4	16	
6	Net Peak Demand on Plant-Megawatts (60 minutes)		44	30	35	51	11	18	18	
7	Plant Hours Connect to Load		7,687	8,010	8,348	5,351	8,348	8,581	4,491	
8	**Net Plant Capability (in megawatts)**									
9	(a) Under Most Favorable Oper Conditions		44	40	35	59	11	23	17	
10	(b) Under the Most Adverse Oper Conditions		44	39	34	58	11	23	17	

11	Average Number of Employees									
12	Net Generation, Exclusive of Plant Use - kWh		102,717,000	104,648,000	93,920,000	128,230,000	27,378,000	66,489,000	35,887,000	7
13	**Cost of Plant**									
14	Land and Land Rights		2,113,726	586,559	204,939	861,147	2,940	881,780	101,777	
15	Structures and Improvements		3,773,012	2,393,924	2,484,450	2,690,521	1,280,366	2,785,348	2,441,131	
16	Reservoirs, Dams, and Waterways		11,680,288	29,169,693	6,907,098	6,844,347	10,335,256	12,847,000	17,401,949	1
17	Equipment Costs		8,897,332	20,514,996	5,355,077	10,022,610	12,301,758	13,022,086	44,266,576	2
18	Roads, Railroads, and Bridges		41,522	52,308	37,614	349,257	36,694	48,818	134,365	
19	Asset Retirement Costs		91,845	39,476	244,715	435,653	219,426	77,238	506,959	
20	Total cost (total 13 thru 20)		26,597,725	52,756,956	15,233,893	21,203,535	24,176,440	29,662,270	64,852,757	4
21	Cost per KW of Installed Capacity (line 20 / 5)		591.1	1,352.7	514.7	353.4	1,439.1	2,059.9	4,053.3	
22	**Production Expenses**									
23	Operation Supervision and Engineering		282,367	108,528	529,814	593,763	299,701	49,280	55,161	
24	Water for Power			485,823	279,689	508,356	153,427			
25	Hydraulic Expenses		45	40	30	60	17	18	21	
26	Electric Expenses		116,362	376,922	1,935	6,882	949,533	205,213	21,550	
27	Misc Hydraulic Power Generation Expenses		58,668	44,515	29,507	71,098	70,458	35,298	13,338	
28	Rents									
29	Maintenance Supervision and Engineering		(8)	(8)	(6)	(11)	(3)	(4)	(4)	
30	Maintenance of Structures		178,685	63,221	20,803	464,323	264,376	207,837	58,393	

31	Maintenance of Reservoirs, Dams, and Waterways		284,506	3,386	1,656	36,869	214,066	135,768	232,897	
32	Maintenance of Electric Plant		99,252	124,688	45,999	129,428	622,318	217,515	515,273	
33	Maintenance of Misc Hydraulic Plant		36,319	7,654	30,943	21,149	63,702	4,988		
34	Total Production Expenses (total 23 thru 33)		1,056,196	1,214,769	940,370	1,831,917	2,637,595	855,913	896,629	
35	Expenses per net kWh	0.0000	0.0103	0.0116	0.0100	0.0143	0.0963	0.0129	0.0250	

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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: ROCKY MOUNTAIN	FERC Licensed Project No. 2413 Plant Name: WALLACE DAM
1	Type of Plant Construction (Conventional or Outdoor)	0	SEMI-OUTDOOR
2	Year Originally Constructed	1995	1979
3	Year Last Unit was Installed	1995	1980
4	Total installed cap (Gen name plate Rating in MW)	278	209
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	260	162
6	Plant Hours Connect to Load While Generating	3,787	2,114
7	Net Plant Capability (in megawatts)	190	213
8	Average Number of Employees		
9	Generation, Exclusive of Plant Use - kWh	188,891,569	100,697,000
10	Energy Used for Pumping	245,367,493	124,564,000
11	Net Output for Load (line 9 - line 10) - Kwh	(56,475,924)	(23,867,000)
12	**Cost of Plant**		
13	Land and Land Rights	1,959,330	17,733,294
14	Structures and Improvements	40,401,857	26,940,737
15	Reservoirs, Dams, and Waterways	73,460,568	57,234,758
16	Water Wheels, Turbines, and Generators	42,039,032	47,897,822
17	Accessory Electric Equipment	13,344,864	9,200,399
18	Miscellaneous Powerplant Equipment	4,250,423	9,055,460
19	Roads, Railroads, and Bridges	3,116,744	1,295,708
20	Asset Retirement Costs		52,590
21	Total cost (total 13 thru 20)	178,572,818	169,410,768
22	Cost per KW of installed cap (line 21 / 4)	642.3	810.6

23	**Production Expenses**		
24	Operation Supervision and Engineering	4,340,858	552,890
25	Water for Power		
26	Pumped Storage Expenses		185
27	Electric Expenses		722,306
28	Misc Pumped Storage Power generation Expenses	639,704	129,025
29	Rents		29,898
30	Maintenance Supervision and Engineering		(35)
31	Maintenance of Structures		559,071
32	Maintenance of Reservoirs, Dams, and Waterways		174,210
33	Maintenance of Electric Plant		816,026
34	Maintenance of Misc Pumped Storage Plant		50,182
35	Production Exp Before Pumping Exp (24 thru 34)	4,980,562	3,033,758
36	Pumping Expenses		
37	Total Production Exp (total 35 and 36)	4,980,562	3,033,758
38	Expenses per kWh (line 37 / 9)	0.0264	0.0301
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	0	0

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 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, anc 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, Pag
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 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		Kind of Fuel (k)
									Fuel Production Expenses (i)	Maintenance Production Expenses (j)	
1	Hydro:										
2	Burton (A)	1927	8.10	8.00	19,568,000	17,145,212	2,116,693	31,268		157,590	
3	Nacoochee (A)	1926	4.80	6.00	12,644,000	12,600,823	2,625,171	27,150		217,529	
4	Flint River (B)	1921	5.40	7.00	34,735,000	25,073,165	4,643,179	879,334		967,838	
5	Estatoah - Retired (C)		0.20	0.00	0	75	375				
6	Langdale - Retired (D)	1907	1.00	0.00	0	4,326	4,326	8,305			
7	Riverview - Retired (E)	1918	0.50	0.00	0	757	1,514	2,860			
8	Solar:										
9	[(a)] Various		28.50	0.00	36,720,870	72,940,001	2,559,298	206,126		479,117	
10	(A) Licensed Project Number 2354.										
11	(B) Licensed Project Number 1218.										
12	(C) Approximately 1928. Record of Owners inadeq.										
13	(D) Licensed Project Number 2341.										
14	(E) Licensed Project Number 2350.										

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: PlantName

Various Solar consists of Dalton, University of Georgia, Falcons Solar Projects, Tri-County Solar Projects, Guyton, Comer, Waynesboro, LaGrange, and McIntosh.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS

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) s
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 incor
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 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 s 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

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)
1	Mossy Branch	Production	Talbot County, GA	38,037	31,863			6,174		
35	TOTAL			38,037	31,863	0	0	6,174	0	0

FOOTNOTE DATA

(a) Concept: PowerPurchasedForStorageOperationsLargePlants

The Costs were determined using the Southern Company Pool Interchange Rate.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 Kw.
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 project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) 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.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)	BALANCE AT BEGINNING OF YEAR				
					Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
36	TOTAL			0	0	0	0	0	0

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

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 kilov 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 s
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; o 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 con
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 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 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 y 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 colum
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, gi 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 operatic 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 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 determ
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	COS
	From	To	Operating	Designated		On Structure of Line Designated	On Structures of Another Line			La
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	500 KV STEEL STRUCTURES									
2	BOWEN	NORCROSS 500 KV LN	500	500	Steel Towers	57.30	11.73	1	1113 ACSR	2
3	BOWEN	TVA 500 KV LN	500	500	Steel Towers	43.04		1	1113 ACSR	
4	BOWEN	UNION CITY #1 500 KV LN	500	500	Steel Towers	48.82		1	1113 ACSR	3
5	BOWEN	UNION CITY #2 500 KV LN	500	500	Steel Towers	57.63		1	1113 ACSR	
6	FARLEY	NORTH TIFTON 500 KV LN	500	500	Steel Towers	96.33		1	1113 ACSR	1
7	FORTSO	N TIFTON 500 KV LN	500	500	Steel Towers	116.57		1	1113 ACSR	5
8	HATCH	OFFERMAN-FLA ST LN 500 KV L	500	500	Steel Towers	88.67		1	1113 ACSR	2
9	HATCH	THALMANN-DUVAL 500 KV LN	500	500	Steel Towers	105.91		1	1113 ACSR	3
10	NORCROSS	OCONEE LN 500 KV LN	500	500	Steel Towers	79.10		1	1113 ACSR	5
11	SCHERER	WALLACE DAM 500 KV LN	500	500	Steel Towers	53.43		1	1113 ACSR	2
12	PLANT VOGTLE	KLONDIKE 500KV LN								

13	PLT SCHERER	O'HARA 500KV LN								
14	VOGTLE	MCINTOSH-THALMANN 500 KV LN	500	500	Steel Towers	221.21		1	1113 ACSR	8
15	VOGTLE	WADLEY 500 KV LN	500	500	Steel Towers	43.55		1	1113 ACSR	1
16	WANSLEY	OHARA 500 KV LN	500	500	Steel Towers	50.78		1	1113 ACSR	2
17	WADLEY	WALLACE DAM 500 KV LN	500	500	Steel Towers	57.02		1	1113 ACSR	2
18	MCGRAU FORD	MOSTELLER SPRINGS	500	500	Steel Towers	34.50		1	1113 ACSR	19
19	VOGTLE BUS #1	VOGTLE 3&4 BUS #3	500	500	Steel Towers	0.19		1	1113 ACSR	
20	VOGTLE BUS #2	VOGTLE 3&4 BUS #4	500	500	Steel Towers	0.19		1	1113 ACSR	
21	THOMSON	VOGTLE 500 KV LINE	500	500	Steel Towers	55.21		1	1113 ACSR	
22	230 KV WOOD STRUCTURES									
23	YATES	BONAIRE	230	230	Wood H-Frame	101.38		1	1033 ACSR	
24	MORGANVILLE	TVA 230KV LN	161	230	Wood H-Frame	0.13		1	477 ACSR	
25	S BAINBRIDGE	FLA ST LN 230 KV LN	230	230	Wood H-Frame	0.09		1	1033 ACSR	
26	230 KV STEEL STRUCTURES									
27	AUGUSTA	NEWSPRINT 230 KV LOOP LN	230	230	Steel H-Frame	8.68		1	1351 ACSR	
28	AUSTIN DRIVE	SCOTTDALE 230 KV LN	230	230	Steel Pole	11.69		1	1351 ACSR	
29	COBB PLACE	WOODSTOCK 230 KV LN	230	230	Steel Pole	10.13		1	1351 ACSR	1
30	BOAT ROCK	ADAMSVILLE 230 KV LN	230	230	Steel Single Pole	7.23		1	1033 ACSR	
31	BONAIRE	NORTH TIFTON 230 KV LN	230	230	Steel H-Frame	77.10		1	795 ACSR	
32	BOULEVARD	BUCKHEAD	230	230	Steel Pole	3.86		1	1351 SSAC	
33	BUCKHEAD	BULL SLUICE	230	230	Steel Pole	10.17		1	1351 ACSR	
34	BOWEN	CARTERSVILLE	230	230	Steel Tower	8.06	7.30	2	795 ACSR	
35	BOWEN	PINSON	230	230	Steel H-Frame	6.62		2	795 ACSR	
36	BOWEN	PINSON-ATLANTIC STEEL 230 K	230	230	Steel H-Frame	19.77		1	795 ACSR	
37	BRANCH	EVANS 230 LINE								

38	BRANCH	GOSHEN 230KV LN	230	230	Steel H-Frame	6.61		1	1351 ACSR	
39	BRANCH	PORTERDALE	230	230	Steel H-Frame	53.01		1	1351 ACSR	
40	KLONDIKE	MORROW	230	230	Steel H-Frame	20.18		1	1351 ACSR	
41	GRADY	KLONDIKE	230	230	Steel H-Frame	0.40		1	795 ACSR	
42	KLONDIKE	PORTERDALE	230	230	Steel Tower	13.43		1	1351 ACSR	
43	GRADY	KLONDIKE	230	230	Steel Tower	5.60		1	795 ACSR	
44	BRANCH	NORCROSS 230 KV LN	230	230	Steel H-Frame	77.65		1	1351 ACSR	
45	BRANCH	WINDER 230 KV LN	230	230	Steel H-Frame	66.37		1	1351 ACSR	
46	CARTERS DAM	COOSAWATTEE 230 KV LN	230	230	Steel H-Frame	0.46		1	1033 ACSR	
47	CENTER	EAST WATKINSVILLE 230								
48	E DALTON	NORCROSS 230 KV LN	230	230	Steel Pole	0.26		1	1351 ACSR	
49	ALPHARETTA	OCEE	230	230	Steel H-Frame	5.46		1	1351 ACSR	
50	CARTERS DAM	EAST DALTON	230	230	Steel H-Frame	19.57		1	1033 ACSR	
51	MCGRAU	FORD LOOP	230	230	Steel H-Frame	1.97	1.65	2	2-795 ACSR	
52	NELSON	OCEE	230	230	Steel H-Frame	30.61		1	1033 ACSR	
53	NORCROSS	OCEE	230	230	Steel H-Frame	10.86		1	1033 ACSR	
54	E. DALTON	OOSTANAULA-PINSON 230KV	230	230	Steel H-Frame	11.41		1	795 ACSR	
55	EVANS	DUM JON 230 KV LN	230	230	Steel Pole	34.11		1	1351 ACSR	4
56	FARLEY	SOUTH BAINBRIDGE 230 KV LN	230	230	Steel H-Frame	53.40		1	1351 ACSR	
57	FORREST RD	S MACON 230KV LN								
58	FORTSON	EAST COLUMBUS 230 KV								
59	GAINESVILLE	CENTER 230 KV LN	230	230	Steel H-Frame	22.91		1	1351 ACSR	
60	GAINESVILLE	CENTER 230 KV LN	230	230	Steel Pole	9.46		1	795 ACSR	
61	GOAT ROCK	BONAIRE 230 KV LN	230	230	Steel H-Frame	9.93		1	795 ACSR	
62	GOAT ROCK	NORTH TIFTON 230 KV LN	230	230	Steel H-Frame	9.93		1	795 ACSR	

63	GOAT ROCK	1ST AVE COLS 230 KV LN	230	230	Steel H-Frame	10.67		2	795 ACSR	
64	GOAT ROCK	1ST AVE COLUMBUS #2 230 KV	230	230	Steel Tower		0.92	2	795 ACSR	
65	GOAT ROCK	1ST AVE COLUMBUS #2 230 KV	230	230	Steel H-Frame	9.74		1	1351 ACSR	
66	SOUTH AUGUSTA	SCE&G (GRANITEVILLE) 230KV	230	230	Concrete Pole	5.13		1	1351 ACSR	
67	GOSHEN	SOUTH AUGUSTA 230 KV LN	230	230	Steel Pole	14.83		1	1351 ACSR	
68	GOSHEN	VOGTLE-WADLEY 230 KV LN	230	230	Steel H-Frame	47.96		1	795 ACSR	
69	GRADY	WABASH-BOULEVARD 230 KV LN	230	230	Steel Pole	3.38		1	1351 AAC	
70	GRADY	WABASH-BOULEVARD 230 KV LN	230	230	Steel Pole	3.69		1	1351 ACSR	
71	HAMMOND	ALABAMA 230 KV LN	230	230	Steel H-Frame	11.15		1	1033 ACSR	
72	HAMMOND	BOWEN NORTH 230 KV LN								
73	HAMMOND	BOWEN SOUTH 230 KV LN	230	230	Steel H-Frame	30.28		1	1351 ACSR	
74	HAMMOND	BREMEN 230 KV LN	230	230	Steel H-Frame	51.94		1	795 ACSR	6
75	HAMMOND	ROCK SPRINGS 230 KV LN	230	230	Steel H-Frame	83.39		1	1351 ACSR	
76	HATCH	OFFERMAN 230KV LN								
77	KINGSLAND	FLA POWER & LIGHT 230 KV LN	230	230	Steel H-Frame	4.18		1	1351 ACSR	
78	MCDONOUGH	EAST POINT 230 KV LN	230	230	Steel Tower	12.35	12.38	1	1351 ACSR	
79	MCDONOUGH	NORTHWEST #1 230 KV LN	230	230	Steel Tower	4.53		1	1351 ACSR	3
80	MCDONOUGH	NORTHWEST #2 230 KV LN	230	230	Steel Tower		4.55	1	1351 ACSR	
81	MCDONOUGH	PEACHTREE-BLVD DC 230 KV LN	230	230	Steel Tower	12.58		1	1351 ACSR	43
82	MITCHELL	N TIFTON 230 KV LN	230	230	Steel H-Frame	35.53		1	795 ACSR	
83	MITCHELL	SLAPPEY DRIVE 230 KV	115	230	Steel H-Frame			1	1351 ACSR	
84	MORROW	ALABAMA STATE LINE 230 KV L	230	230	Steel H-Frame	32.90		1	1351 ACSR	3

85	MORROW	ALABAMA STATE LINE 230 KV L	230	230	Steel Tower	8.42	3.25	2	1351 ACSR	
86	MORROW	ALABAMA STATE LINE 230 KV L	230	230	Steel H-Frame	23.38		1	1351 ACSR	2
87	MORROW	GRADY 230 KV LN	230	230	Steel Tower		9.60	1	795 ACSR	
88	MORROW	WINDER 230 KV LN	230	230	Steel H-Frame	6.63		1	1622 ACSR	
89	MORROW	WINDER 230 KV LN	230	230	Steel H-Frame	38.62		1	795 ACSR	
90	N TIFTON	FLA ST LN 230 KV LN	230	230	Steel H-Frame	64.64		1	1033 ACSR	
91	NORCROSS	MOR FALL-NO MARIETTA 230 KV	230	230	Steel Pole	1.14		1	1351 ACSR	
92	NORCROSS	MOR FALL-NO MARIETTA 230 KV	230	230	Steel Tower	25.36		1	1351 ACSR	
93	NORCROSS	SCOTTDALE-BLVD 230 KV LN	230	230	Steel Pole	13.29		1	1351 ACSR	
94	NORCROSS	SCOTTDALE-BLVD 230 KV LN	230	230	Steel Tower	23.69		2	1351 ACSR	
95	OHARA	SOUTH GRIFFIN 230 KV LN	230	230	Steel H-Frame	2.03		1	1033 ACSR	
96	OFFERMAN	W BRUNSWICK #1 230 KV LN	230	230	Steel H-Frame	39.22		1	1033 ACSR	
97	OFFERMAN	WEST BRUNSWICK 230 KV LN								
98	PARKAIRE	PERIMETER CENTER 230 KV LN	230	230	Steel Pole	6.08		1	1351 ACSR	
99	PERIMETER CENTER	JOHNSON FY-DERING CIR	230	230	Steel Pole	7.21		1	1351 ACSR	
100	PERIMETER CENTER	JOHNSON FY-DERING CIR	230	230	UG Duct	0.20		1	3000 XLPE	
101	E DALTON	ROCK SPRINGS-TVA 230 KV LN	230	230	Steel H-Frame	27.90		1	1351 ACSR	
102	E DALTON	ROCK SPRINGS 230 KV LN	230	230	Steel H-Frame	15.35		1	1351 ACSR	
103	RUSSELL DAM	E. WATKINSVILLE 230 KV LN	230	230	Steel Pole	7.81		1	795 ACSR	
104	RUSSELL DAM	E. WATKINSVILLE 230 KV LN	230	230	Steel H-Frame	62.29		1	1351 ACSR	2
105	S BAINBRIDGE	FLA ST LN 230 KV LN	230	230	Steel H-Frame	32.84		1	1033 ACSR	
106	SOUTH AUGUSTA	15TH ST 230 KV	115	230	Steel Pole	1.23		1	1351 ACSR	

107	JONESBORO	STOCKBRIDGE 230KV	230	230	Steel Pole	5.12		2	1351 ACSR	
108	SOUTHALL	WINDER 230KV LN								
109	STATESBORO	SAVANNAH 230 KV LN	230	230	Steel H-Frame	16.06		1	1033 ACSR	
110	UNION CITY	EAST POINT #1 230 KV LN	230	230	Steel Tower	11.04		1	1590 ACSR	
111	UNION CITY	EAST POINT #2 230 KV LN	230	230	Steel Tower	4.54	6.60	1	1590 ACSR	
112	UNION CITY	SOUTH GRIFFIN 230 KV LN	230	230	Steel H-Frame	2.01		1	1033 ACSR	
113	VIDALIA	W BRUNSWICK 230 KV LN	230	230	Steel H-Frame	100.54		1	1033 ACSR	
114	VILLA RICA	EAST POINT 230 KV LN	230	230	Steel H-Frame	30.76		1	1351 ACSR	
115	WADLEY	WADLEY VIDALIA #2 230 KV LN	230	230	Steel H-Frame	46.13		1	1351 ACSR	
116	WADLEY	WADLEY VIDALIA #1 230 KV LN	230	230	Steel H-Frame	46.16		1	1033 ACSR	
117	WALLACE DAM	EATONTON 230 KV LN	230	230	Steel H-Frame	15.63		1	1351 ACSR	
118	WEST BRUNSWICK	KINGSLAND 230 KV LN	230	230	Steel H-Frame	35.96		1	1351 ACSR	1
119	WEST BRUNSWICK	MCMANUS 230 KV LN	230	230	Steel H-Frame	6.21		1	1351 ACSR	
120	YATES #5	YATES #6 & #7 230 KV LN	230	230	Steel H-Frame	1.40		1	1351 ACSR	
121	YATES	BONAIRE 230 KV LN	230	230	Steel H-Frame	11.07		1	1033 ACSR	
122	YATES	MORROW 230 KV LN	230	230	Steel Tower	11.67		2	1033 ACSR	
123	YATES	MORROW 230 KV LN	230	230	Steel H-Frame	23.39		1	1351 ACSR	
124	MCINTOSH CT TIE 230KV	MCINTOSH CT TIE 230KV							1351 ACSR	
125	KINGSLAND	KINGS BAY #1 230 KV LN	230	230	Steel H-Frame	7.96		1	N/A	
126	COLERAIN	KINGS BAY #2 230 KV LN	230	230	Steel H-Frame	7.87		1	1351 ACSR	
127	ALPHARETTA	OLD ALABAMA RD 230 KV LN	230	230	Steel Pole	2.95		1	1351 ACSR/TW	1
128	VOGTLE	SAVANNAH RIVER PLT (SCEG) 2	230	230	Steel H-Frame	3.99		1	1622 ACSR	
129	BIG SHANTY	WOODSTOCK 230 KV LN							1351 N/A	
130	PONCE DE LEON	ROYAL ATL 230KV								1

131	OLD ALA	MARTINS LANDING 230KV	230	230	Steel Pole	6.12		1		1
132	NORC	SWEET BOT-SUWANEE 230KV	230	230	Steel Pole	28.27		1	1622 ACSR/TW	4
133	NORCROSS	CEDAR VILLAGE-ROYAL ATL 230	230	230	Steel Pole	9.55		1	1622 ACSR/TW	
134	W. MARIETTA	SMYRNA 230 KV LN	230	230	Steel Pole	7.15		1	1622 ACSR	
135	WINDER	SOUTH HALL 230 KV LN							1351 N/A	
136	WINDER	GAINESVILLE 230 KV LN	230	230	Steel H-Frame	45.45		1		
137	WINDER	NORCROSS 230 KV LN	230	230	Steel H-Frame	12.11	1.22	1	1033 ACSR	
138	WINDER	NORCROSS 230 KV LN	230	230	Steel Pole	7.52		1	1033 ACSR/TW	
139	BRANCH	EVANS 230 KV LN	230	230	Steel H-Frame	72.93		1	1622 ACSR	
140	CENTER	MIDDLE FORK 230 KV LN	230	230	Steel H-Frame	26.56		1	1351 ACSR	8
141	MORROW	OHARA	230	230	Steel Pole	12.95		1	1351 ACSR	
142	THOMASTON	BARNESVILLE PRI 230 KV LN	230	230	Steel H-Frame	1.60		1	1351 ACSR	
143	ANTHONY SHOALS	RUSSELL DAM 230 KV LN	230	230	Steel H-Frame	2.88		1	1033 ACSR	
144	CARTERSVILLE	SOUTH ACWORTH 230 KV LN	230	230	Steel H-Frame	15.07		1	1351 ACSR	2
145	CARTERSVILLE	SOUTH ACWORTH 230 KV LN	230	230	Steel Pole	6.71		1	2-795 ACSR	1
146	CARTERSVILLE	MCGRAU FORD 230 KV LN	230	230	Steel H-Frame	18.50		1	2-795 ACSR	7
147	CARTERSVILLE	MCGRAU FORD 230 KV LN	230	230	Steel Tower	35.67		1	1351 ACSR	13
148	TIOGA	ELLIJAY 230 KV LN	230	230	Steel Pole	7.62		1	1351 ACSR	
149	TIOGA	ELLIJAY 230 KV LN	230	230	Steel H-Frame	5.00		1	1622 ACSR	
150	CORNISH MOUNTAIN	PORTERDALE PRI 230 KV	230	230	Steel H-Frame	7.40		1	1622 ACSR	
151	ALBANY	SOWEGA 230 KV LN	230	230	Steel Pole	8.98		1	1351 ACSR	
152	FORTSON	TALBOT COUNTY 230 KV (SONAT	230	230	Steel Pole	1.87		1	1351 ACSR	
153	Augusta 15th St	South Augusta	230	230	Steel Pole	4.02		1	795 ACSR	
154	BLANDFORD	LITTLE OGEECHEE (WHITE) 230	230	230	Steel Tower	24.38		1	1351 ACSR	

155	MCINTOSH	STATESBORO 230 KV (SAV)	230	230	Steel Tower	21.87		1	1033 ACSR	
156	MCINTOSH	STATESBORO 230 KV (SAV)	230	230	Steel H-Frame	15.73		1	1033 ACSR	
157	KRAFT	MCINTOSH (BLACK) 230 KV (SA	230	230	Steel Tower	16.23		1	1033 ACCR	
158	BLANDFORD	MCINTOSH (BLACK) 230 KV (SA	230	230	Steel Tower	8.23		1	1622 ACSR	
159	WEST MCINTOSH	MCINTOSH (BLACK) 230 KV LN	230	230	Steel Tower	0.42		1	1033 ACSR	
160	DEAN FOREST	KRAFT 230 KV (SAV)	230	230	Steel Tower	6.01		1	1351 ACSS	
161	BLANDFORD	LITTLE OGEECHEE (BLACK) 230	230	230	Steel Tower	24.33		1	959 ACSR	
162	HOMELAND	KETTLE CREEK 230 KV	230	230	Steel Pole	20.67		1	1033 ACSR	
163	MCINTOSH CC 230 KV TIE LINE	MCINTOSH CC 230 KV TIE LINE	230	230	Steel Tower	1.27		1	1033 ACSR	
164	BLANDFORD	MCINTOSH (WHITE) 230 KV (SA	230	230	Steel Tower	8.23		1	1351 ACSR	
165	DORCHESTER	LITTLE OGEECHEE 230 KV LN	230	230	Steel H-Frame	21.90		1	1033 ACSR	2
166	KRAFT	MCINTOSH (WHITE) 230 KV (SA	230	230	Steel Tower	16.25		1	1351 ACSR	
167	MCINTOSH	MCINTOSH COAL 230 KV LN	230	230	Steel Tower	0.00		1	1033 ACSR	
168	MCINTOSH	MCINTOSH CT 230 KV LN	230	230	Concrete Three-Pole	0.42		1	795 ACSR	
169	MCINTOSH	PURRYSBURG (SPSCA) 230 KV (	230	230	Steel H-Frame	1.98		1	1033 ACSR	
170	MCINTOSH	WEST MCINTOSH (WHITE) 230 K	230	230	Concrete Pole	0.40		1	1272 ACSS	
171	BOWEN	MCCONNENELL ROAD 230KV	230	230	Steel H-Frame	1.61		1	1351 ACSR	
172	BOWEN	MCCONNENELL ROAD 230KV	230	230	Steel Tower	8.52		1	795 ACSR	
173	MCDONOUGH CC #4 TIE LINE	MCDONOUGH CC #4 TIE LINE	230	230	Steel Pole	0.83		1	795 ACSR	
174	MCDONOUGH CC #5 TIE LINE	MCDONOUGH CC #5 TIE LINE	230	230	Steel Pole	0.77		1	1113 ACSR	
175	JACK MCDONOUGH	SMYRNA 230 KV	230	230	Steel Pole	6.93		1	795 ACSR	4
176	MCDONOUGH CC #6 230 KV TIE LINE	MCDONOUGH CC #6 230 KV TIE LINE	230	230	Steel Pole	0.34		1	795 ACSR	

177	VOGTLE 3&4 UNIT RAT A TRANSMISSION LINE 230KV	VOGTLE 3&4 UNIT RAT A TRANSMISSION LINE 230KV	230	230	Steel Tower	1.02		1	795 ACSR	
178	VOGTLE 3&4 UNIT RAT B 230KV	VOGTLE 3&4 UNIT RAT B 230KV	230	230	Steel Tower	0.60		1	795 ACSR	
179	VOGTLE UNIT 3	230KV OUTPUT LINE	230	230	Steel Tower	0.94		1	1351 ACSR	
180	VOGTLE 3&4 230KV RAT B LINE	VOGTLE 3&4 230KV RAT B LINE	230	230	Steel Pole	5.50		1	1351 ACSS	3
181	BOULEVARD	DEAN FOREST 230KV	230	230	Steel Pole	4.00		1	1351 ACSS	
182	THORNTON RD	TRIBUTARY 230KV	230	230	Steel Pole	2.80		1	1351 ACSR	1
183	POSSUM BRANCH	ROOPVILLE 230KV	230	230	Steel Pole	5.37		1	1351 ACSR	
184	BENNOCK MILL	MECHANIC HILL 230KV	230	230	Steel Pole	1.10		1	1351 ACSR	
185	AUGUSTA CORPORATE PARK	BENNOCK MILL	230	230	Steel Pole	1.20		1	1351 ACSR	
186	AUGUSTA CORP PARK	MECHANIC HILL (WHITE) 230K	230	230	Steel Pole	1.80		1	1351 ACSR	
187	WANSLEY SCRUBBER 230 KV TIE	WANSLEY SCRUBBER 230 KV TIE	230	230	Concrete Pole	2		1	795 ACSR	
188	PLANT BOWEN SCRUBBER TIE LINE UNIT 1 & 2	PLANT BOWEN SCRUBBER TIE LINE UNIT 1 & 2	230	230	Concrete Pole	0.00		1	795 ACSR	
189	HATCH SAT 1E SERVICE 230KV LINE	HATCH SAT 1E SERVICE 230KV LINE	230	230	Steel H-Frame	0.23		1	795 ACSR	
190	HATCH SAT 2E SERVICE 230KV LINE	HATCH SAT 2E SERVICE 230KV LINE	230	230	Steel Pole	0.19		1	795 ACSR	
191	[(a)] 230 KV Underground		230		VAR	0.20	0.00			
192	115 KV Underground		115		VAR	11.99	0.00			
193	115 KV Overhead Wood Lines		115		VAR	4,173.51	32.68			
194	115 KV Overhead Steel Lines		115		VAR	1,025.54	80.94			154
195	69 KV Wood Lines		69		VAR	91.07	23.04			1
196	69 KV Steel Lines		69		VAR	2.79	0.43			
197	46 KV Lines		46		VAR	1,626.34	6.40			42
36	TOTAL					10,619.41	202.69	182		409,59

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: TransmissionLineStartPoint

Resubmission - added lines 191-197.

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed permissible to report in these columns the costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-o 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 cha

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE		CONDUCTORS			Voltage KV (Operating)	Lan and Lan Right
	From	To		Type	Average Number per Miles	Present	Ultimate	Size	Specification	Configuration and Spacing		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	1 OHARA	RIVERDALE 115 KV	(0.02)	SSP	10.00	1	1	795	ACSR	1/PHASE	115	
2	2 OHARA	RIVERDALE 115 KV	0.01	SSP	10.00	1	1	795	ACSR	1/PHASE	115	
3	TALLULAH LODGE	TERRORA 115 KV	0.05	SSP	10.00	1	1	795	ACSR	1/PHASE	115	
44	TOTAL		0.04		30.00	3	3					

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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 char be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattende 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 capac
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole owner equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other thai name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affecte each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation		VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Nu Tran
		Transmission or Distribution (b)	Attended or Unattended (b-1)	Primary Voltage (In MVa) (c)	Secondary Voltage (In MVa) (d)	Tertiary Voltage (In MVa) (e)			
1	1 ABBEVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
2	2 ABCD FARMS PM	Distribution	Unattended	46.00	12.00			1	
3	3 ABCD FARMS PM	Distribution	Unattended	46.00	12.00		0.50	2	
4	4 ACORN CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
5	5 ACWORTH	Distribution	Unattended	115.00	12.00		44.80	2	
6	6 ADAIRSVILLE	Distribution	Unattended	115.00	25.00		80.00	2	
7	7 ADAMS PM	Distribution	Unattended	46.00	12.00		0.25	1	
8	8 ADDLESTONE	Distribution	Unattended	46.00	12.00		5.25	1	
9	9 AERO COMMANDER	Distribution	Unattended	12.00	0.48		1.68	1	
10	10 AINSLIE PM	Distribution	Unattended	46.00	12.00		0.25	1	
11	11 AIR PRODUCTS AND CHEMICALS	Distribution	Unattended	115.00	4.00		44.80	2	
12	12 AIRGAS (Pendergrass)	Distribution	Unattended	230.00	4.00		50.00	2	
13	13 AIRGAS (Pendergrass)	Distribution	Unattended	230.00	25.00		40.00	1	
14	14 AIRLINE	Transmission	Unattended	115.00	46.00		50.00	2	
15	15 AIRPORT ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
16	16 ALADDIN FIBER ONE #1 PD	Distribution	Unattended	46.00	0.48		3.75	1	
17	17 ALADDIN FIBER ONE #2 PD	Distribution	Unattended	46.00	4.00		2.50	1	
18	18 ALADDIN FIBER ONE #2 PD	Distribution	Unattended	46.00	4.00		2.50	1	
19	19 ALADDIN FIBER ONE #6 PD	Distribution	Unattended	46.00	0.48		3.75	1	
20	20 ALADDIN FIBER ONE #7 PD	Distribution	Unattended	46.00	0.48		3.75	1	
21	21 ALADDIN FIBER ONE #8 PD	Distribution	Unattended	46.00	4.00		2.50	1	

22	22 ALADDIN MILLS	Distribution	Unattended	46.00	0.48		10.50	2	
23	23 ALADDIN MILLS #2	Distribution	Unattended	46.00	0.48		7.00	1	
24	24 ALADDIN MILLS #2	Distribution	Unattended	46.00	0.48		7.00	1	
25	25 ALADDIN MILLS #3	Distribution	Unattended	46.00	0.48		6.25	1	
26	26 ALADDIN MILLS #3	Distribution	Unattended	46.00	0.48		6.25	1	
27	27 ALADDIN MILLS (Forsyth)	Distribution	Unattended	12.00	0.60		3.50	1	
28	28 ALAPAHA	Distribution	Unattended	115.00	12.00		10.50	1	
29	29 ALCOVY ROAD	Transmission	Unattended	115.00	25.00		25.00	1	
30	30 ALCOVY ROAD	Transmission	Unattended	115.00	46.00		56.00	1	
31	31 ALDORA MILLS #3	Distribution	Unattended	69.00	4.00		25.00	1	
32	32 ALEXANDER DRIVE	Distribution	Unattended	115.00	13.80		80.00	2	
33	33 ALKEN-ZEIGLER	Distribution	Unattended	46.00	0.48		0.50	1	
34	34 ALLATOONA HEIGHTS PM	Distribution	Unattended	46.00	12.00		0.25	1	
35	35 ALLEN ROAD	Distribution	Unattended	115.00	12.00		80.00	2	
36	36 ALPHARETTA	Distribution	Unattended	230.00	25.00		60.00	1	
37	37 ALTAMAHA BOULEVARD	Distribution	Unattended	115.00	12.00		25.00	1	
38	38 ALTO	Distribution	Unattended	115.00	12.00		25.00	1	
39	39 ALTO	Distribution	Unattended	115.00	12.00		7.00	1	
40	40 AMERICAN GRANITE QUARRIES	Distribution	Unattended	46.00	12.00		2.50	3	
41	41 AMERICUS	Transmission	Unattended	115.00	12.00		50.00	2	
42	42 AMERICUS	Transmission	Unattended	115.00	46.00		50.00	2	
43	43 AMHERST	Distribution	Unattended	115.00	12.00		44.80	2	
44	44 ANCHOR GLASS	Distribution	Unattended	115.00	12.00		10.50	1	
45	45 ANCHOR GLASS	Distribution	Unattended	115.00	12.00		10.00	1	
46	46 ANDERSONVILLE PD	Distribution	Unattended	46.00	12.00		2.50	1	
47	47 ANGLO AMERICAN CLAY TEMPORARY PM	Distribution	Unattended	46.00	12.00		0.25	1	
48	48 ANGLO AMERICAN CLAY TEMPORARY PM	Distribution	Unattended	46.00	12.00		0.50	2	
49	49 ANTHONY PM	Distribution	Unattended	46.00	12.00			2	
50	50 ANTHONY PM	Distribution	Unattended	46.00	12.00		0.25	1	
51	51 ANTIOCH ROAD	Distribution	Unattended	115.00	46.00		60.00	1	
52	52 ANTIOCH ROAD	Distribution	Unattended	115.00	46.00		40.00	1	
53	53 ANTIOCH ROAD	Distribution	Unattended	46.00	12.00		8.40	2	
54	54 APAC (Camak)	Distribution	Unattended	46.00	25.00		14.00	2	
55	55 AQUILLA	Distribution	Unattended	115.00	12.00		25.00	1	
56	56 AQUILLA	Distribution	Unattended	115.00	25.00		25.00	1	

57	57 ARAGON	Distribution	Unattended	46.00	12.00		14.00	2	
58	58 ARAGON PRIMARY	Transmission	Unattended	115.00	46.00		50.00	1	
59	59 ARBOR	Distribution	Unattended	115.00	25.00		25.00	1	
60	60 ARCHER DANIELS MIDLAND (Valdosta)	Distribution	Unattended	115.00	12.00		22.40	1	
61	61 ARGOS (Atlanta)	Distribution	Unattended	115.00	4.00		14.00	2	
62	62 ARLINGTON	Distribution	Unattended	46.00	12.00		7.00	1	
63	63 ARMSTRONG GLASS (Jasper)	Distribution	Unattended	46.00	0.48		1.68	3	
64	64 ARMSTRONG WORLD INDUSTRIES	Distribution	Unattended	115.00	4.00		134.40	4	
65	65 ARMUCHEE	Distribution	Unattended	115.00	12.00		10.50	1	
66	66 ARTESIAN STREET	Distribution	Unattended	115.00	12.00		50.00	2	
67	67 ASAMA COLDWATER MANUFACTURING	Distribution	Unattended	115.00	13.80		44.80	2	
68	68 ASAMA COLDWATER MANUFACTURING	Distribution	Unattended	115.00	13.80		10.50	1	
69	69 ASHBURN PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
70	70 ASHBURN PRIMARY	Distribution	Unattended	115.00	12.00		50.00	2	
71	71 ASHFORD	Distribution	Unattended	230.00	20.00		60.00	1	
72	72 ATHENA	Distribution	Unattended	115.00	25.00		100.00	2	
73	73 ATHENS	Transmission	Unattended	115.00	46.00		50.00	1	
74	74 ATHENS OPERATING PM	Distribution	Unattended	46.00	12.00		0.25	1	
75	75 ATHENS OPERATING PM	Distribution	Unattended	46.00	12.00		0.50	2	
76	76 ATHENS PUMPING	Distribution	Unattended	46.00	4.00		7.00	1	
77	77 ATLANTA FULTON COUNTY WATER TREATMENT	Distribution	Unattended	230.00	12.00		67.20	2	
78	78 ATLANTA WATER STORAGE (Lois Street)	Distribution	Unattended	115.00	4.00		50.00	2	
79	79 ATLANTA WATER TREATMENT (Bolton)	Distribution	Unattended	115.00	4.00		50.00	2	
80	80 ATLANTA WATER TREATMENT (Bolton)	Distribution	Unattended	115.00	4.00		44.80	2	
81	81 ATLANTA WATER WORKS (Adamsville)	Distribution	Unattended	46.00	4.00		1.68	3	
82	82 ATLANTA WATER WORKS (Moores Mill)	Distribution	Unattended	20.00	2.40		2.00	3	
83	83 ATLANTIC DRIVE	Distribution	Unattended	115.00	20.00		120.00	2	
84	84 ATTAPULGUS	Distribution	Unattended	25.00	4.00		7.00	1	
85	85 ATTAPULGUS	Distribution	Unattended	25.00	4.00		7.00	1	
86	86 AUGUSTA AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
87	87 AUGUSTA AREA #4 PM	Distribution	Unattended	46.00	12.00		0.25	1	

88	88 AUGUSTA CORPORATE PARK	Distribution	Unattended	230.00	25.00		25.00	1	
89	89 AUGUSTA NEWSPRINT	Distribution	Unattended	230.00	13.80		224.00	4	
90	90 AUSTELL	Distribution	Unattended	115.00	25.00		33.33	1	
91	91 AUSTELL	Distribution	Unattended	115.00	12.00		44.80	2	
92	92 AUSTELL	Distribution	Unattended	115.00	46.00		50.00	1	
93	93 AUSTELL BOX BOARD	Distribution	Unattended	46.00	0.60		14.00	2	
94	94 AUSTIN DRIVE	Distribution	Unattended	115.00	12.00		67.20	3	
95	95 AUTREY FURNITURE	Distribution	Unattended	46.00	12.00		0.75	3	
96	96 AVONDALE MILL ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
97	97 AVONLEA	Distribution	Unattended	230.00	25.00		120.00	2	
98	98 BAINBRIDGE	Distribution	Unattended	115.00	12.00		44.80	2	
99	99 BAINBRIDGE	Distribution	Unattended	115.00	12.00		47.04	2	
100	100 BAKER PLACE	Distribution	Unattended	115.00	12.00		25.00	1	
101	101 BAKER PLACE	Distribution	Unattended	115.00	12.00		40.00	1	
102	102 BAKERS FERRY ROAD	Distribution	Unattended	230.00	20.00		180.00	3	
103	103 BALDWIN	Distribution	Unattended	115.00	12.00		10.50	1	
104	104 BALDWIN	Distribution	Unattended	115.00	12.00		25.00	1	
105	105 BANNING LAKE PM	Distribution	Unattended	46.00	12.00		0.25	1	
106	106 BARCO #1 (TALLAPOOSA) PD	Distribution	Unattended	46.00	4.00		2.50	1	
107	107 BARNESVILLE	Distribution	Unattended	115.00	12.00		50.00	2	
108	108 BARNETT ROAD	Distribution	Unattended	115.00	25.00		56.00	1	
109	109 BARTLETTS FERRY	Transmission	Unattended	115.00	12.00		22.40	1	
110	110 BARTLETTS FERRY	Transmission	Unattended	115.00	12.00		130.00	1	
111	111 BARTLETTS FERRY	Transmission	Unattended	14.40	0.48		1.12	3	
112	112 BARTLETTS FERRY	Transmission	Unattended	115.00	12.00		30.50	1	
113	113 BARTLETTS FERRY	Transmission	Unattended	13.80	0.48		2.24	2	
114	114 BARTON CHAPEL	Distribution	Unattended	230.00	12.00		33.60	1	
115	115 BARTOW	Distribution	Unattended	46.00	12.00		2.50	3	
116	116 BASE MANUFACTURING	Distribution	Unattended	46.00	0.48		1.68	1	
117	117 BASSETT FURNITURE	Distribution	Unattended	46.00	0.48		3.50	1	
118	118 BATH	Distribution	Unattended	46.00	12.00		14.00	2	
119	119 BATTLECREEK	Distribution	Unattended	115.00	25.00		80.00	2	
120	120 BAXLEY	Distribution	Unattended	115.00	12.00		25.00	1	
121	121 BAXLEY	Distribution	Unattended	115.00	12.00		22.40	1	
122	122 BAXLEY	Distribution	Unattended	115.00	46.00		50.00	2	

123	123 BAYER CROPSCIENCE	Distribution	Unattended	115.00	12.00		7.00	1	
124	124 BEASLEY TIMBER	Distribution	Unattended	46.00	0.48		3.36	2	
125	125 BEASLEY TIMBER #2 PD	Distribution	Unattended	46.00	4.00		2.50	1	
126	126 BEAULIEU AMERICA (Royston)	Distribution	Unattended	46.00	0.60		3.86	2	
127	127 BEAVER DRIVE	Distribution	Unattended	115.00	12.00		40.00	1	
128	128 BEAVER DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
129	129 BEAVERS ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
130	130 BEKAERT STEEL WIRE	Distribution	Unattended	115.00	12.00		44.80	2	
131	131 BELAIR	Distribution	Unattended	115.00	12.00		40.00	1	
132	132 BELL	Distribution	Unattended	115.00	12.00		25.00	1	
133	133 BELLEVUE	Distribution	Unattended	115.00	12.00		33.60	1	
134	134 BELVEDERE	Distribution	Unattended	20.00	12.00		22.40	1	
135	135 BELVEDERE	Distribution	Unattended	115.00	20.00		41.60	1	
136	136 BELVEDERE	Distribution	Unattended	115.00	12.00		22.40	1	
137	137 BEN HILL	Distribution	Unattended	115.00	20.00		50.00	1	
138	138 BENDIX FRICTION MATERIALS	Distribution	Unattended	46.00	0.48		6.25	1	
139	139 BERCKMAN ROAD	Distribution	Unattended	115.00	13.80		40.00	1	
140	140 BERKELEY LAKE	Distribution	Unattended	230.00	25.00		60.00	1	
141	141 BERKELEY LAKE	Distribution	Unattended	230.00	25.00		33.60	1	
142	142 BERKELEY LAKE	Distribution	Unattended	230.00	25.00		50.00	1	
143	143 BETHLEHEM 115/25-KV	Distribution	Unattended	115.00	25.00		25.00	1	
144	144 BEULAH PM	Distribution	Unattended	46.00	12.00		0.25	1	
145	145 BIBB MANUFACTURING (Percale)	Distribution	Unattended	115.00	4.00		14.00	2	
146	146 BIG A	Distribution	Unattended	115.00	12.00		10.50	1	
147	147 BIG CREEK SEWAGE TREATMENT	Distribution	Unattended	115.00	12.00		25.00	1	
148	148 BIG CREEK SEWAGE TREATMENT	Distribution	Unattended	20.00	12.00		44.80	2	
149	149 BIG POPLAR	Distribution	Unattended	25.00	12.00		10.50	1	
150	150 BIG POPLAR	Distribution	Unattended	115.00	12.00		25.00	1	
151	151 BIG POPLAR SPRINGS ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
152	152 BILL FRANKS PM	Distribution	Unattended	46.00	12.00		0.25	1	
153	153 BLACK BEAR PM	Distribution	Unattended	46.00	12.00		0.25	1	
154	154 BLACK CREEK	Distribution	Unattended	115.00	13.80		14.00	1	
155	155 BLACKSHEAR	Distribution	Unattended	115.00	12.00		21.00	2	
156	156 BLACKSMITH	Transmission	Unattended	500.00				3	
157	157 BLACKWELLS	Distribution	Unattended	115.00	25.00		40.00	1	

158	158 BLAKELY PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
159	159 BLANCHARD INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		40.00	1	
160	160 BLOOMFIELD	Distribution	Unattended	115.00	12.00		22.40	1	
161	161 BLOOMFIELD	Distribution	Unattended	115.00	12.00		40.00	1	
162	162 BLOOMINGDALE	Distribution	Unattended	46.00	13.80		25.00	1	
163	163 BLOOMINGDALE	Distribution	Unattended	46.00	13.80		14.00	1	
164	164 BLOSSOM CREEK	Distribution	Unattended	46.00	12.00		12.07	1	
165	165 BLUE CIRCLE AGGREGATES #1 (Lithonia)	Distribution	Unattended	46.00	0.60		2.50	3	
166	166 BLUE RIDGE MOUNTAIN WOODCRAFT	Distribution	Unattended	46.00	0.48		1.68	3	
167	167 BOAT ROCK ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
168	168 BOAT ROCK ROAD	Distribution	Unattended	20.00	12.00		22.40	1	
169	169 BOBBY JONES	Distribution	Unattended	115.00	12.00		25.00	1	
170	170 BOBBY JONES	Distribution	Unattended	115.00	12.00		40.00	1	
171	171 BOGART	Distribution	Unattended	230.00	25.00		25.00	1	
172	172 BOJO	Distribution	Unattended	115.00	25.00		10.50	1	
173	173 BOJO	Distribution	Unattended	115.00	25.00		21.00	2	
174	174 BOLIVAR	Distribution	Unattended	115.00	12.00		25.00	1	
175	175 BOLLING ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
176	176 BOLTON	Distribution	Unattended	115.00	20.00		46.67	1	
177	177 BOLTON	Distribution	Unattended	115.00	46.00		25.00	1	
178	178 BOLTON STREET	Distribution	Unattended	115.00	13.80		33.60	1	
179	179 BOLTON STREET	Distribution	Unattended	115.00	13.80		40.00	1	
180	180 BONANZA	Distribution	Unattended	115.00	25.00		40.00	1	
181	181 BONANZA	Distribution	Unattended	115.00	25.00		67.20	2	
182	182 BONE PM	Distribution	Unattended	46.00	12.00		0.25	1	
183	183 BORAL BRICK	Distribution	Unattended	115.00	13.80		10.50	1	
184	184 BOSTON	Distribution	Unattended	69.00	12.00		7.00	1	
185	185 BOULEVARD (Atlanta)	Transmission	Unattended	115.00	20.00		112.00	2	
186	186 BOULEVARD (Atlanta)	Transmission	Unattended	115.00	20.00		60.00	1	
187	187 BOULEVARD (Savannah)	Transmission	Unattended	115.00	13.80		33.60	1	
188	188 BOULEVARD (Savannah)	Transmission	Unattended	115.00	13.80		33.30	1	
189	189 BOWDON JUNCTION PM	Distribution	Unattended	46.00	12.00		0.25	1	
190	190 BOWEN	Generation	Attended	500.00			2052.00	6	
191	191 BOWEN	Generation	Attended	20.00	4.00		44.80	2	

192	192 BOWEN	Generation	Attended	230.00	13.80		115.00	2	
193	193 BOWEN	Generation	Attended	23.00	4.16		45.00	1	
194	194 BOWEN	Generation	Attended	25.00	4.00		80.00	2	
195	195 BOWEN	Generation	Attended	25.00	0.60		9.60	1	
196	196 BOWEN	Generation	Attended	230.00	25.00		900.00	3	
197	197 BOWEN	Generation	Attended	20.00	13.80		140.00	2	
198	198 BOWEN	Generation	Attended	18.00	4.00		40.00	2	
199	199 BOWEN	Generation	Attended	25.00	13.80		140.00	2	
200	200 BOWEN	Generation	Attended	25.00	4.00		20.00	1	
201	201 BOWEN	Generation	Attended	500.00	25.00		900.00	3	
202	202 BOWEN	Generation	Attended	230.00	4.00		25.00	1	
203	203 BOWEN	Generation	Attended	25.00	4.00		67.20	3	
204	204 BOWEN NPDES	Distribution	Attended	46.00	4.00		3.75	1	
205	205 BOWEN PUMPING	Distribution	Attended	115.00	4.00		22.40	4	
206	206 BOWMAN	Distribution	Unattended	46.00	12.00		5.25	1	
207	207 BOXWOOD	Distribution	Unattended	115.00	12.00		22.40	1	
208	208 BOYD PM	Distribution	Unattended	46.00	12.00		0.25	1	
209	209 BRADLEY INDUSTRIAL PARK	Distribution	Unattended	115.00	25.00		33.60	1	
210	210 BRADLEY INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		40.00	1	
211	211 BRANCH	Transmission	Unattended	230.00	12.00		25.00	1	
212	212 BRENTWOOD	Distribution	Unattended	115.00	12.00		10.50	1	
213	213 BRIAR VISTA	Distribution	Unattended	115.00	20.00		120.00	2	
214	214 BRIAR VISTA	Distribution	Unattended	20.00	12.00		22.40	1	
215	215 BROAD RIVER FOREST PM	Distribution	Unattended	46.00	12.00		0.25	1	
216	216 BROAD RIVER STONE	Distribution	Unattended	46.00	25.00		7.00	1	
217	217 BROADWAY	Distribution	Unattended	115.00	12.00		40.00	2	
218	218 BROADWAY	Distribution	Unattended	115.00	12.00		22.40	1	
219	219 BRODIE METER	Distribution	Unattended	46.00	0.48		2.80	1	
220	220 BRONWOOD	Distribution	Unattended	46.00	12.00		5.25	1	
221	221 BROOKHAVEN BOULEVARD	Distribution	Unattended	115.00	12.00		44.80	2	
222	222 BROOKHAVEN BOULEVARD	Distribution	Unattended	115.00	12.00		40.00	2	
223	223 BROOKLET	Distribution	Unattended	115.00	12.00		10.50	1	
224	224 BROWN AND WILLIAMSON TOBACCO	Distribution	Unattended	115.00	13.80		40.00	1	
225	225 BROWN BROTHERS #2	Distribution	Unattended	12.00	2.40		2.80	3	
226	226 BROWN BROTHERS SAND PIT	Distribution	Unattended	12.00	2.40		7.00	2	
227	227 BROWN FARM ROAD	Distribution	Unattended	115.00	12.00		25.00	1	

228	228 BROWN FARM ROAD	Distribution	Unattended	25.00	12.00		10.50	1	
229	229 BRUNSWICK	Distribution	Unattended	115.00	12.00		80.00	2	
230	230 BUCKHEAD (Madison) (NEW)	Distribution	Unattended	115.00	25.00		25.00	1	
231	231 BUCKHEAD PRIMARY	Distribution	Unattended	230.00	20.00		112.00	2	
232	232 BUCKHEAD PRIMARY	Distribution	Unattended	230.00	20.00		60.00	1	
233	233 BUDWEISER PM	Distribution	Unattended	46.00	12.00		0.75	3	
234	234 BUENA VISTA	Distribution	Unattended	46.00	25.00		10.50	2	
235	235 BUENA VISTA	Distribution	Unattended	46.00	12.00		14.00	2	
236	236 BUFFALO ROAD	Distribution	Unattended	25.00	12.00		10.50	1	
237	237 BUFFALO ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
238	238 BUFORD	Distribution	Unattended	115.00	12.00		25.00	1	
239	239 BUFORD	Distribution	Unattended	115.00	46.00		25.00	1	
240	240 BUHLER QUALITY YARNS	Distribution	Unattended	115.00	12.00		28.00	4	
241	241 BULK FABRICATED PRODUCTS	Distribution	Unattended	46.00	0.48		1.68	1	
242	242 BULL CREEK	Distribution	Unattended	115.00	12.00		80.00	2	
243	243 BULL MOOSE TUBE	Distribution	Unattended	46.00	0.48		5.60	1	
244	244 BURGESS PIGMENT	Distribution	Unattended	46.00	0.48		2.80	1	
245	245 BURGESS PIGMENT #2 PD	Distribution	Unattended	46.00	12.00		5.00	1	
246	246 BURKHALTER ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
247	247 BURNT HICKORY	Distribution	Unattended	115.00	12.00		50.00	2	
248	248 BURTON	Distribution	Unattended	46.00	12.00		7.00	1	
249	249 BUTLER	Distribution	Unattended	230.00	46.00		33.60	1	
250	250 BUTLER	Distribution	Unattended	115.00	46.00		25.00	1	
251	251 BUTLER	Distribution	Unattended	46.00	12.00		5.25	1	
252	252 BUTLER	Distribution	Unattended	46.00	12.00		9.37	2	
253	253 BUTLER STREET	Distribution	Unattended	115.00	20.00		60.00	1	
254	254 BUTLER STREET	Distribution	Unattended	115.00	20.00		180.00	3	
255	255 CADWELL PD	Distribution	Unattended	46.00	12.00		2.50	1	
256	256 CAGLES (Perry)	Distribution	Unattended	115.00	12.00		21.00	2	
257	257 CAGLES (Perry)	Distribution	Unattended	115.00	12.00		25.00	1	
258	258 CALHOUN COUNTY PRISON #1 PD (East)	Distribution	Unattended	46.00	12.00		2.50	1	
259	259 CALHOUN COUNTY PRISON #2 PD (West)	Distribution	Unattended	46.00	12.00		2.50	1	
260	260 CALHOUN ROAD	Distribution	Unattended	115.00	12.00		44.80	2	
261	261 CALHOUN ROAD	Distribution	Unattended	115.00	12.00		10.50	1	

262	262 CAMP JOSEY	Transmission	Unattended	230.00	46.00		46.67	1	
263	263 CAMP JOSEY #2 PD	Distribution	Unattended	46.00	12.00		2.50	1	
264	264 CAMP ODOM PM	Distribution	Unattended	46.00	12.00		0.33	1	
265	265 CANDLER AREA PM	Distribution	Unattended	46.00	12.47		0.25	1	
266	266 CANDLER HOSPITAL	Distribution	Unattended	13.20	0.28		4.20	3	
267	267 CANNONGATE ACRES PM	Distribution	Unattended	46.00	12.00		0.25	1	
268	268 CANON	Distribution	Unattended	46.00	12.00		3.75	1	
269	269 CANTON #2	Distribution	Unattended	115.00	25.00		60.00	1	
270	270 CARL FINDLEY PM	Distribution	Unattended	46.00	12.00		0.25	1	
271	271 CARLTON RURAL PM	Distribution	Unattended	46.00	12.00		0.25	1	
272	272 CARMEUSE MINE #1 PD	Distribution	Unattended	46.00	0.48		2.00	1	
273	273 CARNESVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
274	274 CARPENTER FLAT	Distribution	Unattended	115.00	25.00		40.00	1	
275	275 CARROLLTON	Transmission	Unattended	115.00	46.00		50.00	1	
276	276 CARROLLTON #2	Distribution	Unattended	115.00	12.00		80.00	2	
277	277 CARVER	Transmission	Unattended	46.00	25.00		12.50	1	
278	278 CARWOOD MANUFACTURING	Distribution	Unattended	12.00	0.48		2.10	1	
279	279 CASCADE HEIGHTS	Distribution	Unattended	115.00	20.00		56.00	1	
280	280 CASSVILLE	Distribution	Unattended	46.00	25.00		10.00	1	
281	281 CASTLEBERRY ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
282	282 CASTLEBERRY ROAD	Distribution	Unattended	115.00	12.00		33.60	1	
283	283 CASTLEBERRY ROAD	Distribution	Unattended	25.00	12.00		25.00	1	
284	284 CAVE SPRING #2	Distribution	Unattended	230.00	12.00		25.00	1	
285	285 CDC (Clifton Road)	Distribution	Unattended	20.00	4.00		80.00	4	
286	286 CEDAR CREEK ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
287	287 CEDAR HILL	Distribution	Unattended	230.00	12.00		40.00	1	
288	288 CEDAR SPRINGS	Distribution	Unattended	115.00	12.00		10.50	1	
289	289 CEDAR SPRINGS	Distribution	Unattended	115.00	13.80		80.00	2	
290	290 CEDAR VILLAGE	Distribution	Unattended	230.00	25.00		60.00	1	
291	291 CEDARTOWN	Transmission	Unattended	230.00	46.00		56.00	1	
292	292 CELANESE	Transmission	Unattended	115.00	12.00		33.60	1	
293	293 CENTRAL AVENUE	Distribution	Unattended	115.00	13.80		40.00	1	
294	294 CENTRAL STATE HOSPITAL	Distribution	Unattended	115.00	12.00		25.00	1	
295	295 CERTAINTEED (Athens)	Distribution	Unattended	115.00	25.00		33.60	1	
296	296 CERTAINTEED (Athens)	Distribution	Unattended	115.00	12.00		40.00	1	
297	297 CERTAINTEED (Social Circle)	Distribution	Unattended	46.00	0.48		3.50	1	

298	298 CERTAINTEED (Social Circle)	Distribution	Unattended	46.00	0.48		1.68	1	
299	299 CHADBOURN GOTHAM	Distribution	Unattended	115.00	12.00		40.00	1	
300	300 CHARLES WHITLOCK PM	Distribution	Unattended	46.00	12.00		0.25	1	
301	301 CHATHAM COUNTY INDUSTRIAL	Distribution	Unattended	115.00	25.00		80.00	2	
302	302 CHATSWORTH	Distribution	Unattended	115.00	25.00		67.20	2	
303	303 CHATTAHOOCHEE	Distribution	Unattended	115.00	20.00		56.00	1	
304	304 CHAUNCEY	Distribution	Unattended	115.00	12.00		14.00	2	
305	305 CHEROKEE	Distribution	Unattended	46.00	13.80		14.00	1	
306	306 CHEROKEE BRICK	Distribution	Unattended	12.00	0.60		5.60	2	
307	307 CHEROKEE ROAD	Transmission	Unattended	115.00	12.00		25.00	1	
308	308 CHEROKEE ROAD	Transmission	Unattended	115.00	46.00		25.00	1	
309	309 CHICKAMAUGA	Distribution	Unattended	115.00	12.00		25.00	1	
310	310 CHICKAMAUGA	Distribution	Unattended	115.00	25.00		67.20	2	
311	311 CHICOPEE MANUFACTURING	Distribution	Unattended	115.00	25.00		10.50	1	
312	312 CHICOPEE MANUFACTURING	Distribution	Unattended	115.00	12.00		18.75	2	
313	313 CHICOPEE WOODS PM	Distribution	Unattended	46.00	12.00		0.75	3	
314	314 CHILDRESS PM	Distribution	Unattended	46.00	12.00		0.25	1	
315	315 CHINA HILL ROAD PM	Distribution	Unattended	46.00	12.00		0.50	2	
316	316 CHINA HILL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
317	317 CHINCHILLA ROAD PM	Distribution	Unattended	46.00	12.00		1.00	3	
318	318 CHOKEE PLANTATION PM	Distribution	Unattended	46.00	12.00		0.25	1	
319	319 CHOKEE PLANTATION PM	Distribution	Unattended	46.00	12.00		0.50	2	
320	320 CHOKEE PLANTATION #2 PM	Distribution	Unattended	46.00	0.48		0.30	1	
321	321 CHULA PD	Distribution	Unattended	46.00	12.00		5.00	1	
322	322 CITGO	Distribution	Unattended	13.20	2.40		2.50	3	
323	323 CLARKESVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
324	324 CLARKESVILLE	Distribution	Unattended	46.00	12.00		9.37	2	
325	325 CLARKS BRIDGE	Distribution	Unattended	46.00	12.00	7	10.50	1	
326	326 CLARKSTON	Distribution	Unattended	115.00	25.00		60.00	1	
327	327 CLARKSTON	Distribution	Unattended	115.00	12.00		40.00	1	
328	328 CLAXTON	Transmission	Unattended	115.00	12.00		21.00	2	
329	329 CLAYTON	Distribution	Unattended	115.00	12.00		42.00	4	
330	330 CLAYTON MARCUS PM	Distribution	Unattended	46.00	12.00		0.25	1	
331	331 CLEARWATER ROAD PM	Distribution	Unattended	46.00	12.00		0.75	3	
332	332 CLERMONT JUNCTION	Distribution	Unattended	115.00	25.00		44.80	2	
333	333 CLOUDLAND CANYON	Distribution	Unattended	230.00	25.00		25.00	1	

334	334 CLOUDLAND CANYON	Distribution	Unattended	46.00	12.00		0.25	1	
335	335 CLOVERLEAF	Distribution	Unattended	230.00	12.00		33.60	1	
336	336 CLYATTVILLE	Distribution	Unattended	69.00	12.00		5.25	1	
337	337 COAL MOUNTAIN	Distribution	Unattended	230.00	25.00		40.00	1	
338	338 COATS AMERICAN (Toccoa)	Distribution	Unattended	12.00	4.00		3.50	1	
339	339 COBB	Distribution	Unattended	46.00	12.00		7.00	1	
340	340 COBB COUNTY R. L. SUTTON WRF	Distribution	Unattended	115.00	4.00		25.00	1	
341	341 COBB COUNTY R. L. SUTTON WRF	Distribution	Unattended	115.00	4.00		25.00	1	
342	342 COBB MARIETTA WATER #1 (Johnson Ferry)	Distribution	Unattended	20.00	4.00		6.25	1	
343	343 COBB MARIETTA WATER #2 (Johnson Ferry)	Distribution	Unattended	20.00	4.00		6.25	1	
344	344 COBB MARIETTA WATER (Allatoona)	Distribution	Unattended	115.00	4.00		10.50	2	
345	345 COBB MARIETTA WATER (Lower Roswell)	Distribution	Unattended	20.00	4.00		28.00	2	
346	346 COBB MARIETTA WATER (Wyckoff)	Distribution	Unattended	115.00	4.00		10.50	1	
347	347 COBB MARIETTA WATER (Wyckoff)	Distribution	Unattended	115.00	4.00		10.50	1	
348	348 COBB PLACE	Distribution	Unattended	230.00	25.00		56.00	1	
349	349 COBB PLACE	Distribution	Unattended	230.00	12.00		33.60	1	
350	350 COBLE DAIRY PD	Distribution	Unattended	46.00	12.00		2.50	1	
351	351 COCA COLA (Hapeville)	Distribution	Unattended	115.00	20.00		25.00	1	
352	352 COCHRAN PRIMARY	Distribution	Unattended	115.00	12.00		25.00	1	
353	353 COCHRAN PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
354	354 CODY ROAD	Distribution	Unattended	115.00	12.00		41.70	1	
355	355 COLEMAN	Distribution	Unattended	46.00	12.00		4.69	1	
356	356 COLEMAN (Savannah)	Distribution	Unattended	115.00	13.80		25.00	1	
357	357 COLEMAN (Savannah)	Distribution	Unattended	115.00	13.80		22.40	1	
358	358 COLONELS ISLAND	Distribution	Unattended	115.00	46.00		25.00	1	
359	359 COLONELS ISLAND	Distribution	Unattended	115.00	25.00		25.00	1	
360	360 COLONELS ISLAND	Distribution	Unattended	115.00	46.00		22.40	1	
361	361 COLONIAL PIPELINE (Armuchee)	Distribution	Unattended	115.00	4.00		7.00	1	
362	362 COLONIAL PIPELINE (Bremen)	Distribution	Unattended	115.00	4.00		44.80	2	
363	363 COLONIAL PIPELINE (Bremen)	Distribution	Unattended	115.00	4.00		18.75	2	
364	364 COLONIAL PIPELINE (Dacula)	Distribution	Unattended	115.00	4.00		21.00	2	
365	365 COLONIAL PIPELINE (Dacula)	Distribution	Unattended	115.00	4.00		44.80	2	
366	366 COLONIAL PIPELINE (Danielsville)	Distribution	Unattended	115.00	4.00		21.00	2	

367	367 COLONIAL PIPELINE (Powder Springs)	Distribution	Unattended	115.00	4.00		28.00	2	
368	368 COLONIAL PIPELINE (Smyrna)	Distribution	Unattended	115.00	4.00		21.00	2	
369	369 COLOR IMAGE	Distribution	Unattended	46.00	0.48		2.10	1	
370	370 COLQUITT	Distribution	Unattended	115.00	12.00		25.00	1	
371	371 COLUMBUS	Distribution	Unattended	115.00	12.00		80.00	2	
372	372 COLUMBUS FOUNDRY	Distribution	Unattended	115.00	12.00		56.00	1	
373	373 COLUMBUS FOUNDRY	Distribution	Unattended	115.00	12.00		22.40	1	
374	374 COLUMBUS SEWAGE	Distribution	Unattended	115.00	12.00		14.00	2	
375	375 COLUMBUS SQUARE	Distribution	Unattended	115.00	12.00		67.20	3	
376	376 COMER PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
377	377 COMER PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
378	378 COMMERCE PRIMARY	Distribution	Unattended	115.00	12.00		50.00	2	
379	379 COMMODORE PARK	Distribution	Unattended	115.00	12.00		25.00	1	
380	380 COMOLLI GRANITE	Distribution	Unattended	46.00	0.48		1.12	1	
381	381 CONCORD	Distribution	Unattended	46.00	12.00		3.75	3	
382	382 CONCORD GROVE	Distribution	Unattended	20.00	12.00		25.00	1	
383	383 CONCORD GROVE	Distribution	Unattended	115.00	20.00		80.00	2	
384	384 CONLEY CREEK	Distribution	Unattended	115.00	20.00		80.00	2	
385	385 CONLEY CREEK	Distribution	Unattended	115.00	12.00		40.00	1	
386	386 CONLEY CREEK	Distribution	Unattended	20.00	12.00		25.00	1	
387	387 CONSOLIDATED MINERALS PD	Distribution	Unattended	46.00	12.00		2.50	1	
388	388 CONTAINER CORPORATION OF AMERICA	Distribution	Unattended	25.00	0.48		2.80	1	
389	389 CONYERS	Transmission	Unattended	230.00	46.00		40.00	1	
390	390 CONYERS	Transmission	Unattended	115.00	25.00		44.80	2	
391	391 COOLIDGE	Distribution	Unattended	69.00	12.00		5.25	1	
392	392 COOPER BRIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
393	393 COOPER TIRE	Distribution	Unattended	115.00	13.80		22.40	1	
394	394 COOPER TOOLS	Distribution	Unattended	46.00	0.48		3.50	1	
395	395 COOPER TOOLS	Distribution	Unattended	46.00	0.48		3.50	1	
396	396 COOSA	Distribution	Unattended	115.00	12.00		44.80	2	
397	397 COOSAWATTEE	Transmission	Unattended	115.00	12.00		10.50	1	
398	398 COOSAWATTEE	Transmission	Unattended	115.00	12.00		14.00	2	
399	399 COPPER MINES ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
400	400 CORINTH ROAD	Distribution	Unattended	115.00	25.00		50.00	1	

401	401 CORNELIA	Distribution	Unattended	115.00	46.00		25.00	1	
402	402 CORNELIA	Distribution	Unattended	115.00	12.00		22.40	1	
403	403 CORNELL AVENUE	Distribution	Unattended	46.00	13.80		14.00	1	
404	404 CORNELL AVENUE	Distribution	Unattended	46.00	13.80		14.00	1	
405	405 CORPORATE RIDGE	Distribution	Unattended	115.00	25.00		33.30	1	
406	406 CORPORATE RIDGE	Distribution	Unattended	115.00	25.00		33.60	1	
407	407 COTTON PRIMARY	Transmission	Unattended	230.00	46.00		33.60	1	
408	408 COTTON PRIMARY	Transmission	Unattended	230.00	46.00		40.00	1	
409	409 COUNTY FARM ROAD	Distribution	Unattended	115.00	12.00		10.50	1	
410	410 COVINGTON INDUSTRIAL	Transmission	Unattended	115.00	46.00		50.00	1	
411	411 CRAWFISH CREEK	Transmission	Unattended	230.00	46.00		60.00	1	
412	412 CRAWFORD	Distribution	Unattended	46.00	12.00		14.00	2	
413	413 CRAWFORDVILLE	Distribution	Unattended	46.00	8.00		5.25	1	
414	414 CREEK PARK	Distribution	Unattended	230.00	20.00		120.00	2	
415	415 CREEKWOOD SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
416	416 CROOKED RIVER	Distribution	Unattended	115.00	25.00		44.80	2	
417	417 CROOKED RIVER	Distribution	Unattended	115.00	12.00		22.40	1	
418	418 CROSSGATE	Transmission	Unattended	230.00	25.00		50.00	1	
419	419 CROSSROADS PARKWAY	Distribution	Unattended	115.00	25.00		50.00	1	
420	420 CRYSTAL BLUE GRANITE PM	Distribution	Unattended	46.00	25.00		0.84	3	
421	421 CRYSTAL LAKE	Distribution	Unattended	115.00	25.00		60.00	1	
422	422 CRYSTAL LAKE	Distribution	Unattended	25.00	12.00		7.00	1	
423	423 CSX INTERMODAL (Fairburn)	Distribution	Unattended	115.00	12.00		10.50	1	
424	424 CSX TRANSPORTATION PM (Fitzgerald)	Distribution	Unattended	46.00	12.00		0.50	2	
425	425 CSX TRANSPORTATION PM (Fitzgerald)	Distribution	Unattended	46.00	12.00		0.25	1	
426	426 CULVERTON #3 PM	Distribution	Unattended	46.00	12.00		0.50	2	
427	427 CUMBERLAND	Distribution	Unattended	230.00	20.00		60.00	1	
428	428 CUMMING	Distribution	Unattended	115.00	12.00		89.60	4	
429	429 CUMMING	Distribution	Unattended	115.00	12.00		33.60	1	
430	430 CURRAHEE HEIGHTS	Distribution	Unattended	115.00	12.00		25.00	1	
431	431 CYPRESS POINT	Distribution	Unattended	115.00	13.80		10.50	1	
432	432 DACULA	Distribution	Unattended	115.00	25.00		67.20	2	
433	433 DAHLONEGA PRIMARY	Distribution	Unattended	115.00	12.00		10.50	1	
434	434 DAHLONEGA PRIMARY	Distribution	Unattended	115.00	12.00		25.00	1	

435	435 DAHLONEGA PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
436	436 DALTON	Distribution	Unattended	115.00	46.00		50.00	1	
437	437 DALTON	Distribution	Unattended	115.00	12.00		25.00	1	
438	438 DAMES FERRY	Distribution	Unattended	115.00	12.00		7.00	1	
439	439 DANIMER	Distribution	Unattended	115.00	25.00		50.00	1	
440	440 DARIEN	Distribution	Unattended	115.00	12.00		10.50	1	
441	441 DAVIDSON MINERAL (Lithonia)	Distribution	Unattended	46.00	2.40		6.90	4	
442	442 DAVIE SLICE PM	Distribution	Unattended	46.00	12.00		0.25	1	
443	443 DAVIE SLICE PM	Distribution	Unattended	46.00	12.00		0.25	1	
444	444 DAVIS STREET	Transmission	Unattended	115.00	20.00		240.00	4	
445	445 DAVIS STREET	Transmission	Unattended	115.00	20.00		40.00	1	
446	446 DAVISBORO PD	Distribution	Unattended	46.00	12.00		5.00	1	
447	447 DAWSON	Distribution	Unattended	46.00	25.00		5.25	1	
448	448 DAWSON	Distribution	Unattended	46.00	12.00		10.50	2	
449	449 DAWSON FOREST	Distribution	Unattended	115.00	12.00		21.00	2	
450	450 DAWSON INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		22.40	1	
451	451 DAWSON PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
452	452 DAWSON PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
453	453 DEAL BRANCH	Transmission	Unattended	115.00	46.00		25.00	1	
454	454 DEAN FOREST	Transmission	Unattended	115.00	13.80		33.60	1	
455	455 DEAN STEEL BUILDINGS	Distribution	Unattended	46.00	0.48		1.12	1	
456	456 DEARING	Distribution	Unattended	46.00	25.00		7.00	1	
457	457 DECATUR	Distribution	Unattended	115.00	20.00		60.00	1	
458	458 DECATUR COUNTY INDUSTRIAL	Distribution	Unattended	115.00	12.00		33.60	1	
459	459 DECATUR COUNTY INDUSTRIAL	Distribution	Unattended	115.00	12.00		33.60	1	
460	460 DEKALB COUNTY SCOTT CANDLER WFP	Distribution	Unattended	115.00	4.00		50.00	2	
461	461 DEKALB COUNTY SEWAGE (Snapfinger Rd)	Distribution	Unattended	20.00	12.00		25.00	1	
462	462 DEKALB COUNTY SEWAGE (Snapfinger Rd)	Distribution	Unattended	25.00	12.00		25.00	1	
463	463 DEKALB COUNTY WATER (Holcombe Bridge)	Distribution	Unattended	25.00	4.00		30.00	2	
464	464 DEKALB VOCATIONAL SCHOOL	Distribution	Unattended	12.00	0.48		1.12	1	
465	465 DELTA AIRLINES #1	Distribution	Unattended	115.00	12.00		40.00	1	
466	466 DELTA AIRLINES #1	Distribution	Unattended	115.00	12.00		40.00	1	

467	467 DELTA AIRLINES #2	Distribution	Unattended	20.00	4.00		2.50	1	
468	468 DELTA AIRLINES #2	Distribution	Unattended	20.00	12.00		25.00	1	
469	469 DEMOREST	Distribution	Unattended	46.00	12.00	7	10.50	1	
470	470 DEMOREST	Distribution	Unattended	46.00	12.00		14.00	2	
471	471 DENNIS STATION #2 PD	Distribution	Unattended	46.00	12.00		5.00	1	
472	472 DEPTFORD	Transmission	Unattended	46.00	13.80		50.00	2	
473	473 DERING CIRCLE 115	Distribution	Unattended	115.00	12.00		25.00	1	
474	474 DERING CIRCLE 230	Distribution	Unattended	230.00	20.00		60.00	1	
475	475 DEVEREUX (RETIRED)	Distribution	Unattended	46.00	12.00		0.83	1	
476	476 DEVEREUX (RETIRED)	Distribution	Unattended	46.00	12.00		1.92	2	
477	477 DEXTER	Distribution	Unattended	46.00	12.00		6.25	1	
478	478 DIAMOND HILL AREA PM	Distribution	Unattended	46.00	12.00		0.25	1	
479	479 DIAMOND HILL AREA PM	Distribution	Unattended	46.00	12.00			1	
480	480 DILLARD PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
481	481 DILLARD PRIMARY	Distribution	Unattended	115.00	25.00		44.80	2	
482	482 DITTLER BROTHERS	Distribution	Unattended	20.00	0.48		4.20	1	
483	483 DIVIDEND ROAD	Distribution	Unattended	115.00	12.00		44.80	2	
484	484 DIXIE PECAN PM	Distribution	Unattended	46.00			0.05	1	
485	485 DIXIE PECAN PM	Distribution	Unattended	46.00	0.48		0.05	1	
486	486 DIXIE PIPELINE (Appling)	Distribution	Unattended	12.00	2.40		7.00	2	
487	487 DIXIE PIPELINE (Eatonton)	Distribution	Unattended	46.00	2.40		3.00	3	
488	488 DIXIE PIPELINE (Lumpkin)	Distribution	Unattended	46.00	2.40		3.45	2	
489	489 DIXIE PIPELINE (Milner)	Distribution	Unattended	69.00	2.40		2.50	1	
490	490 DIXIE PIPELINE (Norwood)	Distribution	Unattended	46.00	2.40		14.00	2	
491	491 DIXIE PIPELINE (Putney)	Distribution	Unattended	12.00	4.00		7.00	2	
492	492 DIXIE PIPELINE (Shiloh)	Distribution	Unattended	115.00	2.40		16.80	2	
493	493 DIXIE ROAD	Distribution	Unattended	69.00	12.00		10.50	1	
494	494 DIXON LAKE PM	Distribution	Unattended	46.00	12.00		0.25	1	
495	495 DODD ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
496	496 DODGE AGRICULTURAL PARK PM	Distribution	Unattended	46.00	12.00		0.25	1	
497	497 DODGE EASTMAN INDUSTRIAL PARK	Distribution	Unattended	115.00	12.00		25.00	1	
498	498 DOLCO PACKAGING	Distribution	Unattended	46.00	0.48		3.50	1	
499	499 DONALSONVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
500	500 DONNA WAY PM	Distribution	Unattended	46.00	12.00		0.75	3	
501	501 DORAVILLE	Distribution	Unattended	115.00	46.00		25.00	1	
502	502 DORAVILLE	Distribution	Unattended	115.00	12.00		40.00	1	

503	503 DORSEY TRAILERS #2 PM	Distribution	Unattended	12.00	0.48		0.25	3	
504	504 DOSTER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
505	505 DOSTER ROAD #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
506	506 DOUBLE BRIDGES ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
507	507 DOUBLE CHURCHES ROAD	Distribution	Unattended	115.00	25.00		33.33	1	
508	508 DOUBLEGATE	Distribution	Unattended	115.00	12.00		67.20	2	
509	509 DRURY PM	Distribution	Unattended	46.00	12.00		0.25	1	
510	510 DRURY PM	Distribution	Unattended	46.00	12.00		0.50	2	
511	511 DSM EVERGREEN	Distribution	Unattended	115.00	13.80		25.00	1	
512	512 DUBLIN	Distribution	Unattended	115.00	12.00		50.00	2	
513	513 DUBLIN	Distribution	Unattended	115.00	46.00		50.00	1	
514	514 DULUTH	Distribution	Unattended	115.00	25.00		56.00	1	
515	515 DUM JON	Transmission	Unattended	115.00	46.00		25.00	1	
516	516 DUNCAN BRIDGE ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
517	517 DUNCAN MILL ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
518	518 DUNCAN MILL ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
519	519 DURHAM PARK	Distribution	Unattended	230.00	25.00		67.20	2	
520	520 DUTCHTOWN ROAD	Distribution	Unattended	115.00	13.80		80.00	2	
521	521 EAGLE GRANITE	Distribution	Unattended	46.00	2.40		0.75	3	
522	522 EAST AMERICUS	Distribution	Unattended	115.00	12.00		44.80	2	
523	523 EAST ATHENS	Distribution	Unattended	115.00	12.00		160.00	4	
524	524 EAST AUGUSTA	Distribution	Unattended	115.00	13.80		22.40	1	
525	525 EAST BAINBRIDGE	Distribution	Unattended	115.00	25.00		10.50	1	
526	526 EAST BAINBRIDGE	Distribution	Unattended	115.00	12.00		25.00	1	
527	527 EAST BEACH	Distribution	Unattended	115.00	12.00		25.00	1	
528	528 EAST CUTHBERT	Distribution	Unattended	46.00	12.00		10.50	1	
529	529 EAST DAWSON	Distribution	Unattended	46.00	12.00		14.00	2	
530	530 EAST EVANS	Distribution	Unattended	115.00	12.00		25.00	1	
531	531 EAST EVANS	Distribution	Unattended	115.00	12.00		22.40	1	
532	532 EAST EVANS	Distribution	Unattended	115.00	12.00		33.60	1	
533	533 EAST LUMPKIN	Distribution	Unattended	46.00	12.00		14.00	2	
534	534 EAST MACON	Distribution	Unattended	115.00	12.00		25.00	1	
535	535 EAST MAYSVILLE	Distribution	Unattended	115.00	25.00		50.00	2	
536	536 EAST POINT	Distribution	Unattended	115.00	12.00		25.00	1	
537	537 EAST POINT	Distribution	Unattended	115.00	20.00		50.00	1	

538	538 EAST VALDOSTA	Distribution	Unattended	115.00	12.00		22.40	1	
539	539 EAST VALDOSTA	Distribution	Unattended	115.00	12.00		40.00	1	
540	540 EAST VIDALIA	Distribution	Unattended	115.00	12.00		25.00	1	
541	541 EAST VIDALIA	Distribution	Unattended	115.00	12.00		44.80	2	
542	542 EAST VIENNA	Distribution	Unattended	46.00	12.00		14.00	2	
543	543 EASTANOLLEE	Distribution	Unattended	115.00	12.00		10.50	1	
544	544 EASTANOLLEE	Distribution	Unattended	115.00	12.00		25.00	1	
545	545 EATONTON	Distribution	Unattended	46.00	12.00		10.50	2	
546	546 EATONTON	Distribution	Unattended	46.00	12.00		5.25	1	
547	547 EATONTON PRIMARY	Transmission	Unattended	230.00	46.00		33.60	1	
548	548 EATONTON PRIMARY	Transmission	Unattended	230.00	46.00		22.40	1	
549	549 EATONTON PUMPING PM	Distribution	Unattended	46.00	12.00		0.50	2	
550	550 EATONTON PUMPING PM	Distribution	Unattended	46.00	12.00		0.28	1	
551	551 EATONTON RADIO STATION PM	Distribution	Unattended	46.00	12.00		0.25	1	
552	552 ECHECONNEE	Distribution	Unattended	115.00	12.00		37.56	1	
553	553 EDISON	Distribution	Unattended	46.00	12.00		7.00	1	
554	554 ELANCO	Distribution	Unattended	115.00	4.00		22.40	1	
555	555 ELBERTON PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
556	556 ELLAVILLE	Distribution	Unattended	230.00	12.00		7.50	1	
557	557 ELLENWOOD	Distribution	Unattended	115.00	25.00		60.00	1	
558	558 ELLERSLIE	Distribution	Unattended	230.00	25.00		40.00	1	
559	559 ELLIJAY #2	Distribution	Unattended	46.00	12.00		10.50	2	
560	560 ELLIJAY LUMBER	Distribution	Unattended	46.00	0.48		0.75	3	
561	561 ELLIJAY PRIMARY	Transmission	Unattended	230.00	25.00		40.00	1	
562	562 ELLIJAY PRIMARY	Transmission	Unattended	230.00	12.00		80.00	2	
563	563 ELLIJAY PRIMARY	Transmission	Unattended	230.00	46.00		60.00	1	
564	564 EMORY	Distribution	Unattended	115.00	20.00		56.00	1	
565	565 EMORY	Distribution	Unattended	115.00	20.00		60.00	1	
566	566 ENCORE RECYCLING	Distribution	Unattended	115.00	4.00		10.50	1	
567	567 ENGELHARD (Gordon)	Distribution	Unattended	115.00	12.00		33.60	1	
568	568 ENGELHARD (McIntyre)	Distribution	Unattended	115.00	12.00		112.00	2	
569	569 ENGELHARD (Savannah)	Distribution	Unattended	46.00	4.00		16.80	2	
570	570 ENGINEERED FABRICS	Distribution	Unattended	46.00	2.40		7.50	3	
571	571 ENGLISHVILLE	Distribution	Unattended	46.00	25.00		10.50	1	
572	572 ERCO WORLDWIDE	Distribution	Unattended	230.00	25.00		33.60	1	
573	573 ERCO WORLDWIDE	Distribution	Unattended	230.00	25.00		60.00	1	

574	574 ERCO WORLDWIDE	Distribution	Unattended	230.00	25.00		60.00	1	
575	575 ERICK CHURCH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
576	576 ETHICON	Distribution	Unattended	46.00	0.48		6.25	1	
577	577 ETON	Distribution	Unattended	115.00	25.00		21.00	2	
578	578 EUCHEE CREEK	Distribution	Unattended	115.00	12.00		42.54	1	
579	579 EUHARLEE	Distribution	Unattended	115.00	12.00		25.00	1	
580	580 EUREKA	Distribution	Unattended	115.00	25.00		40.00	1	
581	581 EVANS PM	Distribution	Unattended	46.00	12.00		0.25	1	
582	582 EVANS CLAY	Distribution	Unattended	12.00	2.40		2.80	3	
583	583 EVANS PRIMARY	Transmission	Unattended	115.00	12.00		44.80	2	
584	584 EVANS PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
585	585 EVERGREEN	Distribution	Unattended	115.00	25.00		10.50	1	
586	586 FACTORY SHOALS ROAD	Distribution	Unattended	115.00	25.00		56.00	1	
587	587 FACTORY SHOALS ROAD	Distribution	Unattended	115.00	25.00		60.00	1	
588	588 FACTORY SHOALS ROAD	Distribution	Unattended	115.00	25.00		33.60	1	
589	589 FAIR ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
590	590 FAIR ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
591	591 FAIRINGTON RIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
592	592 FAYETTEVILLE	Distribution	Unattended	115.00	12.00		67.20	3	
593	593 FAYETTEVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
594	594 FAYETTEVILLE ROAD	Distribution	Unattended	115.00	20.00		40.00	1	
595	595 FAYETTEVILLE ROAD	Distribution	Unattended	20.00	12.00		22.40	1	
596	596 FAYETTEVILLE ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
597	597 FENWICK STREET	Distribution	Unattended	115.00	13.80		75.00	3	
598	598 FERGUSON AVENUE	Transmission	Unattended	115.00	13.80		40.00	1	
599	599 FIELDALE (Cornelia)	Distribution	Unattended	115.00	12.00		50.00	2	
600	600 FIELDALE FARMS #1 (Murrayville)	Distribution	Unattended	25.00	0.48		7.00	2	
601	601 FIELDALE FARMS #2 (Murrayville)	Distribution	Unattended	25.00	0.48		7.00	2	
602	602 FIELDALE FARMS (Cornelia)	Distribution	Unattended	12.00	0.48		6.25	1	
603	603 FIELDALE FARMS (Cornelia)	Distribution	Unattended	12.00	0.48		7.00	2	
604	604 FIFE	Distribution	Unattended	115.00	25.00		80.00	2	
605	605 FIFTEENTH STREET	Transmission	Unattended	115.00	13.80		40.00	1	
606	606 FIFTEENTH STREET	Transmission	Unattended	115.00	13.80		120.00	3	
607	607 FIFTY SECOND STREET	Distribution	Unattended	115.00	13.80		80.00	2	
608	608 FIRST AVENUE	Transmission	Unattended	115.00	12.00		50.00	2	

609	609 FIRST UNITED ETHANOL	Distribution	Unattended	46.00	25.00		21.00	2	
610	610 FISHING CREEK	Distribution	Unattended	115.00	12.00		25.00	1	
611	611 FITZGERALD	Transmission	Unattended	115.00	46.00		25.00	1	
612	612 FLAT CREEK	Distribution	Unattended	115.00	12.00		33.60	1	
613	613 FLAT CREEK SEWAGE TREATMENT	Distribution	Unattended	46.00	12.00		7.00	1	
614	614 FLAT ROCK ROAD	Distribution	Unattended	115.00	25.00		33.60	1	
615	615 FLAT SHOALS ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
616	616 FLAV-O-RICH IRVINDALE DAIRY	Distribution	Unattended	20.00	0.48		3.50	1	
617	617 FLEMING	Distribution	Unattended	115.00	25.00		10.50	1	
618	618 FLINT RIVER HYDRO	Generation	Attended	46.00	2.40		8.00	1	
619	619 FLINT RIVER PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
620	620 FLINT RIVER PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
621	621 FLIPPEN	Distribution	Unattended	115.00	25.00		25.00	1	
622	622 FLIPPEN	Distribution	Unattended	115.00	25.00		50.00	1	
623	623 FLORIDA ROCK (Griffin)	Distribution	Unattended	46.00	4.00		2.50	1	
624	624 FLOWERY BRANCH	Distribution	Unattended	115.00	12.00		22.40	1	
625	625 FLOWERY BRANCH	Distribution	Unattended	115.00	25.00		25.00	1	
626	626 FOLKSTON	Distribution	Unattended	25.00	20.00		22.40	1	
627	627 FOLKSTON	Distribution	Unattended	115.00	25.00		22.40	1	
628	628 FOLKSTON	Distribution	Unattended	115.00	20.00		25.00	1	
629	629 FOREST PARK	Distribution	Unattended	115.00	25.00		44.80	2	
630	630 FOREST PARK	Distribution	Unattended	115.00	25.00		56.00	1	
631	631 FORREST LAKE	Distribution	Unattended	230.00	25.00		25.00	1	
632	632 FORREST LAKE	Distribution	Unattended	230.00	12.00		50.00	2	
633	633 FORREST ROAD (Columbus)	Distribution	Unattended	115.00	25.00		33.60	1	
634	634 FORREST ROAD (Columbus)	Distribution	Unattended	115.00	12.00		40.00	1	
635	635 FORREST ROAD (Macon)	Distribution	Unattended	115.00	12.00		41.70	1	
636	636 FORREST ROAD (Macon)	Distribution	Unattended	115.00	25.00		25.00	1	
637	637 FORSTMANN (Louisville)	Distribution	Unattended	115.00	12.00		9.38	1	
638	638 FORT BENNING	Transmission	Unattended	115.00	46.00		22.40	1	
639	639 FORT BENNING	Transmission	Unattended	115.00	46.00		56.00	1	
640	640 FORT BENNING #2	Transmission	Unattended	115.00	46.00		60.00	1	
641	641 FORT BENNING SOLAR (IC-356)	Generation	Attended	46.00	13.80		40.00	1	
642	642 FORT GAINES	Distribution	Unattended	115.00	12.00		10.50	1	

643	643 FORT GILLEM	Distribution	Unattended	115.00	25.00		25.00	1	
644	644 FORT GILLEM	Distribution	Unattended	115.00	12.00	14	22.40	1	
645	645 FORT GORDON	Distribution	Unattended	115.00	12.00		80.00	2	
646	646 FORT GORDON	Distribution	Unattended	115.00	12.00		33.60	1	
647	647 FORT GORDON #2	Distribution	Unattended	115.00	12.00		80.00	2	
648	648 FORT GORDON HOSPITAL	Distribution	Unattended	115.00	12.00		25.00	1	
649	649 FORT GORDON SOLAR (IC-387)	Generation	Attended	115.00	34.50		40.00	1	
650	650 FORT MCPHERSON	Distribution	Unattended	20.00	12.00		14.00	2	
651	651 FORT STEWART	Distribution	Unattended	115.00	25.00		100.00	2	
652	652 FORT STEWART SOLAR (IC-385)	Generation	Attended	115.00	34.50		50.00	1	
653	653 FORTY FIFTH STREET	Distribution	Unattended	115.00	12.00		25.00	1	
654	654 FORTY FIFTH STREET	Distribution	Unattended	115.00	12.00		22.40	1	
655	655 FOWLER STREET	Distribution	Unattended	115.00	20.00		112.00	2	
656	656 FOWLER STREET	Distribution	Unattended	115.00	20.00		60.00	1	
657	657 FOX TRACE PM	Distribution	Unattended	46.00	12.00		0.25	1	
658	658 FRANKLIN	Distribution	Unattended	115.00	12.00		22.40	1	
659	659 FRANKLIN	Distribution	Unattended	25.00	12.00		5.00	2	
660	660 FRANKLIN ALUMINUM	Distribution	Unattended	12.00	0.48		3.50	1	
661	661 FREDERICA	Distribution	Unattended	115.00	25.00		44.80	2	
662	662 FRITO-LAY (Kathleen)	Distribution	Unattended	115.00	25.00		25.00	1	
663	663 FRUIT OF THE LOOM (Dillard)	Distribution	Unattended	25.00	4.00		7.00	1	
664	664 FULGHUM FIBRES PD (Dewy Rose)	Distribution	Unattended	46.00	12.00		2.50	1	
665	665 FURNACE ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
666	666 FURYS FERRY	Distribution	Unattended	115.00	12.00		33.60	1	
667	667 FURYS FERRY	Distribution	Unattended	115.00	12.00		25.00	1	
668	668 GA ARMY NATIONAL GUARD	Distribution	Unattended	46.00	12.00		7.00	1	
669	669 GAILLARD PRIMARY	Transmission	Unattended	230.00	46.00		80.00	2	
670	670 GAINER COTTON GIN	Distribution	Unattended	46.00	12.00		5.25	1	
671	671 GAINESVILLE #1	Transmission	Unattended	115.00	46.00		50.00	1	
672	672 GAINESVILLE #2	Distribution	Unattended	115.00	46.00		50.00	1	
673	673 GAINESVILLE #2	Distribution	Unattended	115.00	25.00		25.00	1	
674	674 GAINESVILLE #2	Distribution	Unattended	115.00	25.00		55.74	2	
675	675 GAINESVILLE WATER WORKS	Distribution	Unattended	46.00	4.00		14.00	2	
676	676 GAINESVILLE WATER WORKS #2	Distribution	Unattended	46.00	2.40		3.00	2	

677	677 GALLAGER PM	Distribution	Unattended	46.00	12.00		0.25	1	
678	678 GARDEN CITY	Distribution	Unattended	115.00	13.80		50.00	2	
679	679 GARDEN CITY TERMINAL WEST	Distribution	Unattended	46.00	4.00		21.00	2	
680	680 GARNETT RIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
681	681 GEO SPECIALTY CHEMICAL (HENKEL)	Distribution	Unattended	46.00	0.60		3.50	1	
682	682 GEORGE ANDREWS LOCK & DAM PM	Distribution	Unattended	46.00	12.00		0.50	2	
683	683 GEORGETOWN	Distribution	Unattended	46.00	12.00		4.69	1	
684	684 GEORGETOWN (Savannah)	Distribution	Unattended	115.00	13.80		33.60	1	
685	685 GEORGIA BAPTIST VILLAGE	Distribution	Unattended	12.00	4.00		3.13	1	
686	686 GEORGIA BIOMASS	Distribution	Unattended	115.00	25.00		40.00	1	
687	687 GEORGIA BOARD OF CORRECTIONS	Distribution	Unattended	115.00	12.00		9.38	1	
688	688 GEORGIA IRON WORKS	Distribution	Unattended	115.00	12.00		25.00	1	
689	689 GEORGIA MARBLE #4 (Talking Rock)	Distribution	Unattended	46.00	4.00		4.69	1	
690	690 GEORGIA MARBLE #5 (Marble Hill)	Distribution	Unattended	46.00	2.40		7.50	2	
691	691 GEORGIA MARBLE (Marble Hill)	Distribution	Unattended	46.00	2.40		9.37	2	
692	692 GEORGIA MARBLE (Tate)	Distribution	Unattended	46.00	2.40		2.50	3	
693	693 GEORGIA MARBLE (Tate)	Distribution	Unattended	46.00	12.00		2.50	1	
694	694 GEORGIA PACIFIC (Brunswick)	Distribution	Unattended	115.00	13.80		120.00	2	
695	695 GEORGIA PACIFIC (Durand)	Distribution	Unattended	115.00	12.00		9.38	1	
696	696 GEORGIA PACIFIC (Ellabell)	Distribution	Unattended	115.00	13.80		10.50	1	
697	697 GEORGIA PACIFIC (Monticello)	Distribution	Unattended	69.00	12.00		22.40	1	
698	698 GEORGIA PACIFIC (Sterling)	Distribution	Unattended	115.00	12.00		7.00	1	
699	699 GEORGIA PACIFIC (Vienna)	Distribution	Unattended	115.00	12.00		25.00	1	
700	700 GEORGIA PACIFIC (Warrenton)	Distribution	Unattended	46.00	12.00		7.00	1	
701	701 GEORGIA PACIFIC GYPSUM (Savannah)	Distribution	Unattended	46.00	13.80		25.00	1	
702	702 GEORGIA PACIFIC SAWMILL (Albany)	Distribution	Unattended	115.00	12.00		10.50	1	
703	703 GEORGIA PORTS AUTHORITY	Distribution	Unattended	46.00	13.80		25.00	1	
704	704 GEORGIA PORTS AUTHORITY	Distribution	Unattended	46.00	13.80		25.00	1	
705	705 GEORGIA SQUARE	Distribution	Unattended	115.00	25.00		33.30	1	
706	706 GEORGIA STATE PATROL - FAA BEACON PM	Distribution	Unattended	46.00	12.00		2.50	1	
707	707 GEORGIA SYNTHETICS	Distribution	Unattended	46.00	0.48		3.50	1	
708	708 GEORGIA TECH	Distribution	Unattended	230.00	20.00		120.00	2	

709	709 GEORGIA TECH RESEARCH (Cobb)	Distribution	Unattended	46.00	4.00		4.69	1	
710	710 GEORGIA TUBING	Distribution	Unattended	12.00	0.48		5.60	2	
711	711 GERDAU	Distribution	Unattended	34.50	13.80		29.80	1	
712	712 GERDAU	Distribution	Unattended	230.00	13.80		60.00	1	
713	713 GERDAU	Distribution	Unattended	230.00	34.50	14	72.80	1	
714	714 GERDAU	Distribution	Unattended	230.00	34.50		145.60	2	
715	715 GERDAU	Distribution	Unattended	230.00	34.50		72.80	1	
716	716 GERDAU	Distribution	Unattended	34.50				6	
717	717 GIBSON	Distribution	Unattended	46.00	12.00		14.00	2	
718	718 GIBSON	Distribution	Unattended	46.00	12.00		7.00	1	
719	719 GILMAN PAPER (Fitzgerald)	Distribution	Unattended	115.00	12.00		11.20	2	
720	720 GLENNVILLE	Distribution	Unattended	115.00	12.00		21.00	2	
721	721 GLYNDALE ROAD	Distribution	Unattended	115.00	12.00		44.80	2	
722	722 GOAT ROCK #2	Distribution	Unattended	115.00	25.00		14.00	2	
723	723 GOAT ROCK HYDRO	Generation	Attended	115.00	12.00		35.00	1	
724	724 GOAT ROCK HYDRO	Generation	Attended	12.00	0.48		0.75	1	
725	725 GOAT ROCK HYDRO	Generation	Attended	115.00	4.00		12.50	1	
726	726 GODFREY ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
727	727 GODLEY TRACT	Distribution	Unattended	115.00	13.80		33.60	1	
728	728 GOLD MINE	Distribution	Unattended	115.00	12.00		44.80	2	
729	729 GOLDEN PEANUT (Dawson)	Distribution	Unattended	46.00	12.00		7.00	1	
730	730 GOODSON ROAD #2 PM	Distribution	Unattended	46.00	12.00		0.75	3	
731	731 GOODYEAR TIRE (Social Circle)	Distribution	Unattended	46.00	2.40		4.69	1	
732	732 GOODYEAR TIRE (Social Circle)	Distribution	Unattended	46.00	0.48		2.10	1	
733	733 GOODYEAR TIRE (Social Circle)	Distribution	Unattended	46.00	0.48		1.68	1	
734	734 GORDON	Transmission	Unattended	115.00	12.00		25.00	1	
735	735 GORDON	Transmission	Unattended	115.00	12.00		10.50	1	
736	736 GORDON ROAD	Distribution	Unattended	115.00	25.00		80.00	2	
737	737 GOSHEN (Savannah)	Distribution	Unattended	115.00	13.80		22.40	1	
738	738 GOSHEN (Savannah)	Distribution	Unattended	115.00	25.00		50.00	1	
739	739 GOSSEN	Distribution	Unattended	46.00	0.48		2.80	1	
740	740 GOUGH CITY PD	Distribution	Unattended	46.00	12.00		5.00	1	
741	741 GRABALL	Distribution	Unattended	115.00	12.00		7.00	1	
742	742 GRADY	Distribution	Unattended	115.00	20.00		40.00	1	

743	743 GRADY	Distribution	Unattended	115.00	20.00		60.00	1	
744	744 GRADY FLOYD PM	Distribution	Unattended	46.00	12.00		0.25	1	
745	745 GRAHAM PACKAGING #5 PD	Distribution	Unattended	46.00	0.48		3.75	1	
746	746 GRANITEVILLE (Sibley)	Distribution	Unattended	13.80	0.60		8.40	2	
747	747 GRAPHIC PACKAGING	Distribution	Unattended	115.00	13.80		80.00	2	
748	748 GRAPHIC PACKAGING (Augusta)	Distribution	Unattended	115.00	13.80		67.20	2	
749	749 GRAVITT	Distribution	Unattended	115.00	25.00		40.00	1	
750	750 GRAY	Distribution	Unattended	115.00	12.00		42.00	2	
751	751 GREAT SOUTHWEST AMUSEMENT PARK	Distribution	Unattended	46.00	12.00		6.25	1	
752	752 GREAT SOUTHWEST AMUSEMENT PARK	Distribution	Unattended	46.00	12.00		5.25	1	
753	753 GREEN ACRES	Distribution	Unattended	115.00	25.00		22.40	1	
754	754 GREENBRIAR	Distribution	Unattended	115.00	12.00		25.00	1	
755	755 GREENBRIAR	Distribution	Unattended	115.00	12.00		21.00	2	
756	756 GREENS MILL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
757	757 GREENSBORO	Distribution	Unattended	115.00	12.00		21.00	2	
758	758 GREENVILLE	Distribution	Unattended	46.00	12.00		7.00	1	
759	759 GREENVILLE PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
760	760 GREENWOOD PARK	Distribution	Unattended	115.00	25.00		120.00	2	
761	761 GREYSTONE PM	Distribution	Unattended	46.00	12.00		0.25	1	
762	762 GREYSTONE GOLF #2 PM	Distribution	Unattended	46.00	12.00		0.33	1	
763	763 GRIFFIN ROAD	Distribution	Unattended	115.00	12.00		80.00	2	
764	764 GROVE POINT ROAD	Distribution	Unattended	115.00	13.80		25.00	1	
765	765 GROVE POINT ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
766	766 GROVETOWN PRIMARY	Distribution	Unattended	115.00	12.00		40.00	1	
767	767 GUARDIAN AUTOMOTIVE #1	Distribution	Unattended	46.00	0.48		3.50	1	
768	768 GULFSTREAM #1	Distribution	Unattended	46.00	4.00		9.38	1	
769	769 GULFSTREAM #2	Distribution	Unattended	46.00	4.00		8.40	1	
770	770 GULFSTREAM #3	Distribution	Unattended	46.00	25.00		10.00	1	
771	771 GULFSTREAM HANGAR	Distribution	Unattended	46.00	4.00		7.00	1	
772	772 GUM CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
773	773 GUTHRIE PM	Distribution	Unattended	46.00	12.00		0.25	1	
774	774 GWINNETT COUNTY WFP (Shoal Creek)	Distribution	Unattended	25.00	4.00		30.00	2	
775	775 GWINNETT COUNTY WFP (Shoal Creek)	Distribution	Unattended	115.00	25.00		50.00	2	
776	776 GWINNETT STREET	Distribution	Unattended	115.00	13.80		22.40	1	

777	777 HAHIRA	Distribution	Unattended	115.00	12.00		21.00	2	
778	778 HAIRSTON ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
779	779 HAIRSTON ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
780	780 HAMILTON CROSSING ROAD	Distribution	Unattended	46.00	25.00		7.00	1	
781	781 HAMILTON ROAD	Distribution	Unattended	115.00	25.00		100.00	2	
782	782 HAMILTON ROAD	Distribution	Unattended	25.00	12.00		25.00	1	
783	783 HANSON AGGREGATES (Athens)	Distribution	Unattended	46.00	2.40		2.50	3	
784	784 HAPEVILLE	Distribution	Unattended	115.00	20.00		56.00	1	
785	785 HARD LABOR CREEK ESTATES PM	Distribution	Unattended	46.00	12.00		0.25	1	
786	786 HARGROVE ROAD	Distribution	Unattended	115.00	20.00		112.00	2	
787	787 HARLEM	Distribution	Unattended	230.00	25.00		25.00	1	
788	788 HARMONY BLUE GRANITE #1	Distribution	Unattended	46.00	0.60		0.75	3	
789	789 HARRISON	Distribution	Unattended	46.00	12.00		5.25	1	
790	790 HARTFORD PM	Distribution	Unattended	46.00	12.00		0.25	1	
791	791 HARTSFIELD FIFTH RUNWAY BRIDGE	Distribution	Unattended	115.00	25.00		10.50	1	
792	792 HARTSFIELD JACKSON	Distribution	Unattended	115.00	20.00		60.00	1	
793	793 HARTSFIELD JACKSON	Distribution	Unattended	115.00	20.00		80.00	2	
794	794 HARTWELL	Distribution	Unattended	115.00	12.00		50.00	2	
795	795 HARTWELL SERIES REACTOR	Transmission	Unattended	230.00				6	
796	796 HATCH	Generation	Attended	500.00	25.00		1200.00	3	
797	797 HATCH	Generation	Attended	500.00	230.00		1800.00	4	
798	798 HATCH	Generation	Attended	230.00			1200.00	1	
799	799 HATCH	Generation	Attended	25.00	4.00		28.00	1	
800	800 HATCH	Generation	Attended	25.00	2.40		25.00	1	
801	801 HATCH	Generation	Attended	4.00	0.60		1.34	2	
802	802 HATCH	Generation	Attended	25.00	4.00		33.60	1	
803	803 HATCH	Generation	Attended	25.00	4.00		35.00	1	
804	804 HATCH	Generation	Attended	230.00	4.00		44.00	1	
805	805 HATCH	Generation	Attended	0.60	0.21		0.17	1	
806	806 HATCH	Generation	Attended	500.00				6	
807	807 HATCH SITE #1	Distribution	Unattended	115.00	12.00		21.00	2	
808	808 HATCH SITE #2	Distribution	Unattended	230.00	12.00		25.00	1	
809	809 HAWTHORNE	Distribution	Unattended	115.00	12.00		22.40	1	
810	810 HAWTHORNE	Distribution	Unattended	115.00	12.00		33.60	1	

811	811 HAZLEHURST PRIMARY	Transmission	Unattended	115.00	46.00		50.00	1	
812	812 HAZLEHURST PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
813	813 HAZLEHURST WOOD PELLETS	Distribution	Unattended	115.00	12.00		25.00	1	
814	814 HEMPHILL WATER TREATMENT	Distribution	Unattended	115.00	4.00		50.00	2	
815	815 HERCULES (Covington)	Distribution	Unattended	115.00	12.00		44.80	2	
816	816 HERCULES (Savannah)	Distribution	Unattended	13.20	0.48		2.50	3	
817	817 HERITAGE HILLS PM	Distribution	Unattended	46.00	12.00		0.25	1	
818	818 HERRINGTON ROAD	Distribution	Unattended	115.00	25.00		60.00	1	
819	819 HIGHTOWER	Distribution	Unattended	115.00	20.00		60.00	1	
820	820 HIGHTOWER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
821	821 HIGHWAY 106 PM (Commerce)	Distribution	Unattended	46.00	12.00		0.25	1	
822	822 HIGHWAY 16 PM (Eatonton)	Distribution	Unattended	46.00	12.00		0.84	3	
823	823 HIGHWAY 51 PM (Hartwell)	Distribution	Unattended	46.00	12.00		0.25	1	
824	824 HIGHWAY 515 PM (Ellijay)	Distribution	Unattended	46.00	12.00		0.25	1	
825	825 HILL STREET	Distribution	Unattended	230.00	20.00		180.00	3	
826	826 HINESVILLE PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
827	827 HINESVILLE PRIMARY	Transmission	Unattended	115.00	12.00		40.00	1	
828	828 HIRAM	Distribution	Unattended	46.00	12.00		5.25	1	
829	829 HOBBS PM	Distribution	Unattended	46.00	12.00		0.25	1	
830	830 HOGANSVILLE	Distribution	Unattended	115.00	12.00		10.50	1	
831	831 HOLLY DRIVE INDUSTRIAL	Distribution	Unattended	115.00	13.80		10.50	1	
832	832 HOLLY SPRINGS	Distribution	Unattended	115.00	25.00		50.00	1	
833	833 HOMERVILLE	Distribution	Unattended	115.00	25.00		25.00	1	
834	834 HON	Distribution	Unattended	46.00	0.48		1.68	1	
835	835 HONDA	Distribution	Unattended	115.00	12.00		42.00	4	
836	836 HORSELEG CREEK	Distribution	Unattended	115.00	12.00		10.50	1	
837	837 HOUSTON CHAPEL	Distribution	Unattended	115.00	20.00		100.00	2	
838	838 HOWARD #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
839	839 HUB JUNCTION PM	Distribution	Unattended	46.00	12.00		0.25	1	
840	840 HUDSON WIRE	Distribution	Unattended	46.00	0.48		1.12	1	
841	841 HUDSON WIRE	Distribution	Unattended	46.00	0.48		2.10	1	
842	842 HUNTER FIELD	Distribution	Unattended	46.00	13.80		50.00	2	
843	843 HUNTSMAN PIGMENTS	Distribution	Unattended	115.00	25.00		10.50	1	
844	844 HUSQVARNA	Distribution	Unattended	46.00	0.48		3.50	1	
845	845 HUSQVARNA	Distribution	Unattended	46.00	0.48		2.80	1	

846	846 HUTCHINSON ISLAND	Distribution	Unattended	115.00	25.00		50.00	2	
847	847 HYUNDAI MOTORS	Distribution	Unattended	230.00	25.00		100.00	1	
848	848 HYUNDAI MOTORS	Distribution	Unattended	230.00	25.00		60.00	1	
849	849 HYUNDAI MOTORS	Distribution	Unattended	115.00	25.00		60.00	1	
850	850 HYUNDAI MOTORS	Distribution	Unattended	230.00	25.00		120.00	1	
851	851 IDEAL WOOD PELLETS PD	Distribution	Unattended	46.00	25.00		5.00	1	
852	852 IDLEWOOD	Distribution	Unattended	230.00	20.00		56.00	1	
853	853 INDIAN TRACE PM	Distribution	Unattended	46.00	12.00		0.25	1	
854	854 INDUSTRIAL BOULEVARD	Distribution	Unattended	115.00	12.00		22.40	1	
855	855 INDUSTRIAL PARK DRIVE	Distribution	Unattended	46.00	0.48		2.80	1	
856	856 INLAND ROME	Distribution	Unattended	115.00	13.80		21.00	2	
857	857 INLAND ROME	Distribution	Unattended	115.00	13.80		67.20	3	
858	858 INTERFOR (Baxley)	Distribution	Unattended	46.00	4.00		14.00	2	
859	859 INTERNATIONAL PAPER (Gordon)	Distribution	Unattended	115.00	4.00		15.00	2	
860	860 INTERNATIONAL PLAYTEX	Distribution	Unattended	46.00	0.60		2.00	3	
861	861 INTERSTATE CENTRE	Distribution	Unattended	115.00	25.00		25.00	1	
862	862 INTERSTATE PAPER	Distribution	Unattended	115.00	12.00		21.00	2	
863	863 INTERSTATE PAPER	Distribution	Unattended	115.00	12.00		67.20	2	
864	864 INTERSTATE PAPER	Distribution	Unattended	115.00	12.00		33.60	1	
865	865 INTRENCHMENT CREEK SEWAGE	Distribution	Unattended	20.00	4.00		4.69	1	
866	866 ISSAC HALL PM	Distribution	Unattended	46.00	12.00		0.25	1	
867	867 J. C. PENNEY	Distribution	Unattended	115.00	12.00		25.00	1	
868	868 J. M. HUBER (Commerce)	Distribution	Unattended	115.00	12.00		10.50	1	
869	869 J. M. HUBER (Reids)	Distribution	Unattended	46.00	4.00		12.50	2	
870	870 J. M. HUBER MINE #1 (Marble Hill) PM	Distribution	Unattended	46.00	12.00		0.75	3	
871	871 J. R. YOUNG PM	Distribution	Unattended	46.00	12.00		0.25	1	
872	872 J. T. RYERSON & SON #1	Distribution	Unattended	46.00	25.00		10.50	2	
873	873 J. T. RYERSON & SON #2	Distribution	Unattended	46.00	0.48		2.80	1	
874	874 J. WILLFORD PM (Vesta)	Distribution	Unattended	46.00	12.00		0.25	1	
875	875 JACK MCDONOUGH	Generation	Attended	230.00	13.80		60.00	1	
876	876 JACK MCDONOUGH	Generation	Attended	115.00	13.80		60.00	1	
877	877 JACK MCDONOUGH CC #4	Generation	Attended	230.00			432.00	1	
878	878 JACK MCDONOUGH CC #4	Generation	Attended	230.00			345.00	1	
879	879 JACK MCDONOUGH CC #4	Generation	Attended	115.00			345.00	1	
880	880 JACK MCDONOUGH CC #5	Generation	Attended	230.00			432.00	1	

881	881 JACK MCDONOUGH CC #5	Generation	Attended	115.00			345.00	1	
882	882 JACK MCDONOUGH CC #5	Generation	Attended	25.00			50.00	2	
883	883 JACK MCDONOUGH CC #5	Generation	Attended	230.00			345.00	1	
884	884 JACK MCDONOUGH CC #6	Generation	Attended	115.00	4.00		25.00	1	
885	885 JACK MCDONOUGH CC #6	Generation	Attended	230.00			690.00	2	
886	886 JACK MCDONOUGH CC #6	Generation	Attended	230.00			432.00	1	
887	887 JACKSON COUNTY HEALTH CENTER PM	Distribution	Unattended	46.00	12.00		0.25	1	
888	888 JACKSON COUNTY SENIOR CITIZENS PM	Distribution	Unattended	46.00	12.00		0.25	1	
889	889 JAMES SHORT PM	Distribution	Unattended	46.00	12.00		0.25	1	
890	890 JAMESTOWN	Distribution	Unattended	115.00	12.00		22.40	1	
891	891 JEFFERSONVILLE	Distribution	Unattended	115.00	12.00		10.50	1	
892	892 JEFFERSONVILLE	Distribution	Unattended	115.00	12.00		44.80	2	
893	893 JEKYLL ISLAND	Distribution	Unattended	46.00	12.00		7.00	1	
894	894 JEKYLL ISLAND	Distribution	Unattended	46.00	12.00		9.37	2	
895	895 JENNINGS PM	Distribution	Unattended	46.00	12.00		0.25	1	
896	896 JERED BROWN BROTHERS	Distribution	Unattended	115.00	4.00		11.20	2	
897	897 JESSIE PORCH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
898	898 JESUP	Transmission	Unattended	115.00	12.00		25.00	1	
899	899 JESUP CITY	Distribution	Unattended	115.00	12.00		22.40	1	
900	900 JEWELL	Distribution	Unattended	46.00	12.00		5.25	1	
901	901 JIMMY CARGILL PM	Distribution	Unattended	46.00	12.00		0.25	1	
902	902 JOHNS CREEK	Distribution	Unattended	230.00	25.00		60.00	1	
903	903 JOHNS CREEK	Distribution	Unattended	230.00	12.00		67.20	2	
904	904 JOHNS CREEK	Distribution	Unattended	230.00	25.00		56.00	1	
905	905 JOHNS CREEK	Distribution	Unattended	230.00	12.00		40.00	1	
906	906 JOHNS MANVILLE INTERNATIONAL	Distribution	Unattended	115.00	4.00		25.00	1	
907	907 JOHNS MANVILLE INTERNATIONAL	Distribution	Unattended	115.00	4.00		44.80	2	
908	908 JOHNSON FERRY ROAD	Distribution	Unattended	230.00	20.00		56.00	1	
909	909 JONES CREEK	Distribution	Unattended	115.00	12.00		41.70	1	
910	910 JONESBORO	Distribution	Unattended	115.00	25.00		56.44	1	
911	911 JUNCTION CITY MINING PD	Distribution	Unattended	46.00	12.00		2.50	1	
912	912 JUNCTION CITY MINING #3 PD	Distribution	Unattended	46.00	4.00		2.50	1	
913	913 KAMIN (Wrens)	Distribution	Unattended	46.00	4.00		5.25	1	
914	914 KAMIN (Wrens)	Distribution	Unattended	46.00	12.00		5.25	1	

915	915 KAMIN (Wrens)	Distribution	Unattended	46.00	4.00		7.00	1	
916	916 KAMIN MINE (Thomson)	Distribution	Unattended	46.00	4.00		10.50	2	
917	917 KAOLIN	Transmission	Unattended	115.00	25.00		33.60	1	
918	918 KAOLIN	Transmission	Unattended	115.00	46.00		25.00	1	
919	919 KATHWOOD DRIVE	Distribution	Unattended	115.00	12.00		40.00	1	
920	920 KEDRON	Distribution	Unattended	115.00	12.00		25.00	1	
921	921 KEITH WHITE PD	Distribution	Unattended	46.00	12.00		2.50	1	
922	922 KELLOGGS SNACKS	Distribution	Unattended	13.80	0.48		3.50	1	
923	923 KENNESAW	Distribution	Unattended	115.00	25.00		40.00	1	
924	924 KENNESAW	Distribution	Unattended	115.00	12.00		33.60	1	
925	925 KERRY #2 PD	Distribution	Unattended	46.00	0.48		2.50	1	
926	926 KERRY #3 PD	Distribution	Unattended	46.00	0.48		2.50	1	
927	927 KERRY #4 PD	Distribution	Unattended	46.00	0.48		2.50	1	
928	928 KETTLE CREEK	Distribution	Unattended	115.00	12.00		44.80	2	
929	929 KEYSTONE MEMORIALS	Distribution	Unattended	46.00	0.48		2.00	6	
930	930 KIA MOTORS	Distribution	Unattended	115.00	13.80		100.00	2	
931	931 KIA MOTORS	Distribution	Unattended	115.00	13.80		22.40	1	
932	932 KIMBALL BRIDGE	Distribution	Unattended	230.00	12.00		40.00	1	
933	933 KIMBALL BRIDGE	Distribution	Unattended	25.00	12.00		33.60	1	
934	934 KIMBALL BRIDGE	Distribution	Unattended	230.00	25.00		60.00	1	
935	935 KIMBALL BRIDGE	Distribution	Unattended	230.00	25.00		56.00	1	
936	936 KINCHAFOONEE	Distribution	Unattended	115.00	12.00		7.00	1	
937	937 KINCHAFOONEE	Distribution	Unattended	115.00	46.00		25.00	1	
938	938 KING AMERICA	Distribution	Unattended	115.00	12.00		7.00	1	
939	939 KING SPRINGS ROAD	Distribution	Unattended	25.00	20.00		25.00	1	
940	940 KING SPRINGS ROAD	Distribution	Unattended	115.00	20.00		120.00	2	
941	941 KING STREET	Distribution	Unattended	115.00	25.00		33.60	1	
942	942 KING STREET	Distribution	Unattended	115.00	25.00		33.60	1	
943	943 KINGS BAY SOLAR (IC-391)	Generation	Attended	230.00	34.50		40.00	1	
944	944 KINGSLAND	Distribution	Unattended	230.00	115.00		300.00	1	
945	945 KINGSLAND	Distribution	Unattended	115.00	12.00		40.00	1	
946	946 KINGSLAND	Distribution	Unattended	115.00	12.00		25.00	1	
947	947 KINGSTON	Distribution	Unattended	230.00	25.00		40.00	1	
948	948 KIOKEE ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
949	949 KIRKHILL MANUFACTURING	Distribution	Unattended	46.00	2.40		5.00	3	

950	950 KIRKWOOD	Distribution	Unattended	115.00	20.00		60.00	1	
951	951 KOYO BEARING	Distribution	Unattended	46.00	12.00		7.00	1	
952	952 KRAFT 115	Transmission	Attended	7.62	0.12			2	
953	953 L. L. BARNES PM	Distribution	Unattended	46.00	12.00		0.25	1	
954	954 LAFARGE AGGREGATES #1 Douglasville	Distribution	Unattended	46.00	0.48		2.24	2	
955	955 LAFARGE AGGREGATES #4 PD Oxford	Distribution	Unattended	46.00	0.48		2.50	1	
956	956 LAGRANGE	Distribution	Unattended	115.00	12.00		33.60	1	
957	957 LAGRANGE	Distribution	Unattended	115.00	46.00		50.00	2	
958	958 LAKE JENNIFER PM	Distribution	Unattended	46.00	12.00		0.25	1	
959	959 LAKE LANIER	Distribution	Unattended	115.00	25.00		44.80	2	
960	960 LAKE LANIER	Distribution	Unattended	115.00	25.00		33.33	1	
961	961 LAKE OCONEE	Distribution	Unattended	115.00	25.00		50.00	1	
962	962 LAKE OCONEE	Distribution	Unattended	115.00	25.00		33.30	1	
963	963 LAKE RIDGE PARKWAY	Distribution	Unattended	115.00	4.00		10.50	1	
964	964 LAKE SINCLAIR	Distribution	Unattended	115.00	25.00		10.50	1	
965	965 LAKE SUSIE PM	Distribution	Unattended	46.00	12.00		0.25	1	
966	966 LAKE TYRONE PD	Distribution	Unattended	46.00	25.00		5.00	1	
967	967 LAKELAND	Distribution	Unattended	115.00	12.00		21.00	2	
968	968 LAKELAND	Distribution	Unattended	115.00	12.00		10.50	1	
969	969 LAKEWOOD	Distribution	Unattended	20.00				6	
970	970 LAKEWOOD	Distribution	Unattended	115.00	20.00		50.00	1	
971	971 LANGBOARD (Quitman)	Distribution	Unattended	115.00	12.00		10.50	1	
972	972 LANGBOARD (Quitman)	Distribution	Unattended	115.00	12.00		7.00	1	
973	973 LANGDALE	Distribution	Unattended	115.00	4.00		7.00	1	
974	974 LANZATECH	Distribution	Unattended	115.00	25.00		60.00	1	
975	975 LAST LAKE	Distribution	Unattended	230.00	12.00		33.60	1	
976	976 LAWRENCEVILLE HIGHWAY	Distribution	Unattended	115.00	20.00		60.00	1	
977	977 LEE HARRIS PM	Distribution	Unattended	46.00	12.00		0.75	3	
978	978 LEESBURG	Distribution	Unattended	115.00	12.00		25.00	1	
979	979 LESLIE	Distribution	Unattended	46.00	12.00		5.25	1	
980	980 LEWIS DRIVE	Distribution	Unattended	115.00	13.80		80.00	2	
981	981 LEWIS SIGN PM	Distribution	Unattended	46.00	0.24		0.03	1	
982	982 LEXINGTON COMPONENTS	Distribution	Unattended	46.00	0.48		3.50	1	
983	983 LIBERTY	Distribution	Unattended	115.00	13.80		25.00	1	
984	984 LIKEN INDUSTRIES	Distribution	Unattended	46.00	0.48		0.50	1	

985	985 LILBURN	Distribution	Unattended	115.00	25.00		33.60	1	
986	986 LIMESTONE CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
987	987 LINDALE #2	Distribution	Unattended	115.00	46.00		50.00	2	
988	988 LINDALE #2	Distribution	Unattended	115.00	12.00		25.00	1	
989	989 LINDBERGH	Distribution	Unattended	230.00	20.00		120.00	2	
990	990 LINWOOD WRF	Distribution	Unattended	115.00	12.00		25.00	1	
991	991 LINWOOD WRF	Distribution	Unattended	115.00	4.00		6.25	1	
992	992 LIQUID CARBONIC	Distribution	Unattended	13.80	4.00		5.00	1	
993	993 LITE-N-TIE (Postell) PM	Distribution	Unattended	46.00	12.00		1.00	3	
994	994 LITHONIA	Distribution	Unattended	25.00	20.00		33.60	1	
995	995 LITHONIA	Distribution	Unattended	115.00	25.00		33.60	1	
996	996 LITHONIA	Distribution	Unattended	115.00	25.00		56.00	1	
997	997 LITHONIA LIGHTING	Distribution	Unattended	46.00	12.00		4.69	1	
998	998 LITTLE NEW YORK PM	Distribution	Unattended	46.00	12.00		0.25	1	
999	999 LITTLE RIVER	Distribution	Unattended	115.00	25.00		60.00	1	
1000	1000 LITTLE RIVER	Distribution	Unattended	115.00	12.00		10.50	1	
1001	1001 LIZELLA	Distribution	Unattended	115.00	12.00		10.50	1	
1002	1002 LLOYD SHOALS	Transmission	Attended	12.00	4.00		5.60	1	
1003	1003 LLOYD SHOALS HYDRO	Generation	Attended	12.00	2.40		12.50	1	
1004	1004 LLOYD SHOALS HYDRO	Generation	Attended	12.00	2.40		10.00	1	
1005	1005 LOCH LAUREL	Distribution	Unattended	115.00	12.00		25.00	1	
1006	1006 LOCKEBY PM	Distribution	Unattended	46.00	7.20		0.25	1	
1007	1007 LOCKHEED MARTIN #1	Distribution	Unattended	115.00	12.00		80.00	2	
1008	1008 LOCKHEED MARTIN #2	Distribution	Unattended	46.00	12.00		5.60	1	
1009	1009 LOCKHEED MARTIN WIND TUNNEL	Distribution	Unattended	115.00	4.00		89.60	4	
1010	1010 LONG CANE	Distribution	Unattended	115.00	25.00		40.00	1	
1011	1011 LOOKOUT VALLEY	Transmission	Unattended	115.00	25.00		25.00	1	
1012	1012 LOOKOUT VALLEY	Transmission	Unattended	115.00	46.00		60.00	1	
1013	1013 LOUISVILLE AREA #3 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1014	1014 LOUISVILLE AREA #7 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1015	1015 LOUISVILLE PRIMARY	Distribution	Unattended	115.00	12.00		10.50	1	
1016	1016 LUCENT TECHNOLOGIES #1 (OFS FITEL)	Distribution	Unattended	115.00	13.80		93.33	2	
1017	1017 LUCENT TECHNOLOGIES #2 (OFS FITEL)	Distribution	Unattended	115.00	13.80		50.00	2	
1018	1018 LUDOWICI PRIMARY	Transmission	Unattended	115.00	12.00		10.50	1	

1019	1019 LUMBER CITY	Distribution	Unattended	46.00	12.00		7.00	1	
1020	1020 LYLE CIRCLE PD	Distribution	Unattended	46.00	25.00		3.75	1	
1021	1021 M A INDUSTRIES	Distribution	Unattended	12.00	0.48		1.68	1	
1022	1022 M&M MARS	Distribution	Unattended	115.00	4.00		10.50	1	
1023	1023 MABLETON	Distribution	Unattended	115.00	25.00		40.00	1	
1024	1024 MABLETON	Distribution	Unattended	115.00	25.00		40.00	1	
1025	1025 MACON COUNTY PRISON #1 PD (South)	Distribution	Unattended	46.00	12.00		2.50	1	
1026	1026 MACON COUNTY PRISON #1 PD (South)	Distribution	Unattended	46.00	12.00		2.50	1	
1027	1027 MADRAS	Distribution	Unattended	115.00	12.00		10.50	1	
1028	1028 MADRAS	Distribution	Unattended	115.00	25.00		25.00	1	
1029	1029 MAGNOLIA	Transmission	Unattended	115.00	13.80		33.60	1	
1030	1030 MAGNOLIA	Transmission	Unattended	46.00	13.80		25.00	1	
1031	1031 MAGNOLIA BLUFF	Distribution	Unattended	115.00	12.00		10.50	1	
1032	1032 MAGNOLIA BLUFF	Distribution	Unattended	25.00	12.00		7.00	1	
1033	1033 MAGNOLIA MANOR	Distribution	Unattended	46.00	0.48		1.00	2	
1034	1034 MAGNOLIA MANOR	Distribution	Unattended	46.00	0.48		2.24	4	
1035	1035 MAGNOLIA PARK	Distribution	Unattended	115.00	12.00		50.00	2	
1036	1036 MAGNOLIA ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1037	1037 MAIN STREET #2 PD	Distribution	Unattended	46.00	25.00		5.00	1	
1038	1038 MALL OF GEORGIA	Distribution	Unattended	115.00	25.00		67.20	2	
1039	1039 MANCHESTER	Distribution	Unattended	115.00	25.00		42.00	4	
1040	1040 MANN ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1041	1041 MANSFIELD	Distribution	Unattended	46.00	25.00		21.00	3	
1042	1042 MAR-JAC POULTRY #1	Distribution	Unattended	46.00	0.48		3.50	1	
1043	1043 MARBLE VALLEY	Distribution	Unattended	46.00	12.00		7.00	1	
1044	1044 MARION SPENCE ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1045	1045 MARK EVANS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1046	1046 MARK GLASS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1047	1047 MARK GLASS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1048	1048 MARSHALLVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1049	1049 MARTA ANNEX	Distribution	Unattended	20.00	0.48		4.69	1	
1050	1050 MARTIN HEIGHTS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1051	1051 MARTIN MARIETTA (Camak)	Distribution	Unattended	46.00	2.40		4.50	3	
1052	1052 MARTIN MARIETTA (Gray)	Distribution	Unattended	46.00	2.40		6.25	1	
1053	1053 MARTIN MARIETTA (Johns Creek)	Distribution	Unattended	115.00	25.00		10.50	1	

1054	1054 MARTIN MARIETTA (Junction City)	Distribution	Unattended	46.00	12.00		5.25	1	
1055	1055 MARTIN MARIETTA (Martinez)	Distribution	Unattended	13.80	2.40		5.00	1	
1056	1056 MARTIN MARIETTA (Tyrone)	Distribution	Unattended	46.00	2.40		4.17	5	
1057	1057 MARTIN MARIETTA (Warrenton)	Distribution	Unattended	46.00	12.00		2.50	3	
1058	1058 MARVIN GRIFFIN ROAD	Distribution	Unattended	115.00	13.80		33.00	1	
1059	1059 MARVIN GRIFFIN ROAD	Distribution	Unattended	115.00	13.80		33.60	1	
1060	1060 MCBEAN ROAD	Distribution	Unattended	115.00	13.80		22.40	1	
1061	1061 MCBEAN ROAD	Distribution	Unattended	115.00	13.80		25.00	1	
1062	1062 MCCREE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1063	1063 MCCREE PM	Distribution	Unattended	46.00	12.00		0.56	2	
1064	1064 MCDONOUGH	Distribution	Unattended	115.00	12.00		25.00	1	
1065	1065 MCDONOUGH	Distribution	Unattended	115.00	25.00		40.00	1	
1066	1066 MCDONOUGH	Distribution	Unattended	115.00	12.00		22.40	1	
1067	1067 MCDONOUGH CONSTRUCTION	Distribution	Unattended	20.00	0.28		0.34	3	
1068	1068 MCGRAU FORD	Transmission	Unattended	13.80	0.48		1.00	1	
1069	1069 MCGRAU FORD SVS	Transmission	Unattended	230.00			200.00	4	
1070	1070 MCINTOSH	Transmission	Unattended	115.00	25.00		40.00	1	
1071	1071 MCINTOSH	Transmission	Unattended	115.00	25.00		25.00	1	
1072	1072 MCINTOSH CC	Generation	Attended	230.00			645.00	3	
1073	1073 MCINTOSH CC	Generation	Attended	230.00			670.00	2	
1074	1074 MCINTOSH CC	Generation	Attended	230.00			250.00	1	
1075	1075 MCINTOSH CT	Generation	Attended	13.80	0.48	0	2.00	1	
1076	1076 MCINTOSH CT	Generation	Attended	13.80	0.48	0	4.50	3	
1077	1077 MCINTOSH CT	Generation	Attended	13.80	13.80		5.98	1	
1078	1078 MCINTOSH CT	Generation	Attended	13.80	0.48	0	17.94	3	
1079	1079 MCINTOSH CT	Generation	Attended	230.00	13.80		880.00	4	
1080	1080 MCINTOSH TRAIL	Distribution	Unattended	115.00	25.00		25.00	1	
1081	1081 MCMANUS	Generation	Attended	13.80	2.40		3.22	1	
1082	1082 MCMANUS	Generation	Attended	2.40	0.48		2.24	1	
1083	1083 MCMANUS	Generation	Attended	115.00	13.20		120.00	2	
1084	1084 MCMANUS	Generation	Attended	13.80	2.40		2.50	1	
1085	1085 MCMANUS	Generation	Attended	13.80	2.40		3.36	2	
1086	1086 MCMANUS	Generation	Attended	13.80	0.48		3.86	3	
1087	1087 MCMANUS	Generation	Attended	13.80	2.40		4.48	2	

1088	1088 MCMANUS	Generation	Attended	115.00	13.20		56.00	1	
1089	1089 MCMANUS	Generation	Attended	2.40	0.48		0.56	1	
1090	1090 MCMANUS	Generation	Attended	230.00	13.20		396.00	3	
1091	1091 MCMANUS	Generation	Attended	2.40	0.48		0.30	1	
1092	1092 MCPHERSON MANUFACTURING	Distribution	Unattended	46.00	0.48		3.50	1	
1093	1093 MCRAE	Transmission	Unattended	115.00	46.00		25.00	1	
1094	1094 MCRAE #2	Distribution	Unattended	46.00	12.00		5.25	1	
1095	1095 MCRAE #2	Distribution	Unattended	46.00	12.00		4.69	1	
1096	1096 MEADOWS LAKE #1 PM	Distribution	Unattended	46.00	12.00		0.33	1	
1097	1097 MEADOWS SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
1098	1098 MECHANIC HILL	Distribution	Unattended	230.00	12.00		80.00	2	
1099	1099 MEDUSA PORTLAND CEMENT	Distribution	Unattended	115.00	4.00		25.00	1	
1100	1100 MEDUSA PORTLAND CEMENT	Distribution	Unattended	115.00	4.00		37.50	4	
1101	1101 MEDUSA PORTLAND CEMENT #2	Distribution	Unattended	46.00	4.00		1.67	5	
1102	1102 MEDUSA PORTLAND CEMENT #3	Distribution	Unattended	46.00	2.40		1.50	3	
1103	1103 MEIGS	Distribution	Unattended	46.00	12.00		5.25	1	
1104	1104 MELDRIM	Transmission	Unattended	115.00	13.80		22.40	1	
1105	1105 MELDRIM	Transmission	Unattended	115.00	46.00	13	112.00	1	
1106	1106 MELDRIM	Transmission	Unattended	115.00	13.80		25.00	1	
1107	1107 MENLO	Distribution	Unattended	46.00	12.00		14.00	2	
1108	1108 MERIWETHER PARK	Distribution	Unattended	115.00	25.00		40.00	1	
1109	1109 MERIWETHER ROAD	Distribution	Unattended	115.00	12.00		50.00	2	
1110	1110 METAL PRODUCTS #1	Distribution	Unattended	12.00	0.48		1.12	1	
1111	1111 METTER	Distribution	Unattended	115.00	12.00		25.00	1	
1112	1112 METTER AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1113	1113 METTER PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
1114	1114 METTER PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1115	1115 MIDWAY	Distribution	Unattended	115.00	25.00		120.00	2	
1116	1116 MILL CITY SEWAGE PM	Distribution	Unattended	46.00	12.00		0.50	2	
1117	1117 MILL CITY SEWAGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1118	1118 MILLEDGEVILLE	Distribution	Unattended	115.00	46.00		25.00	1	
1119	1119 MILLEDGEVILLE	Distribution	Unattended	115.00	12.00		50.00	2	
1120	1120 MILLEN	Distribution	Unattended	115.00	12.00		25.00	1	

1121	1121 MILLEN AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1122	1122 MILLEN AREA #3 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1123	1123 MILLEN PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1124	1124 MILLHAVEN ANNEX	Transmission	Unattended	115.00	46.00		112.00	1	
1125	1125 MILLHAVEN ANNEX	Transmission	Unattended	115.00	13.80		25.00	1	
1126	1126 MILLIKEN (Alma)	Distribution	Unattended	115.00	4.00		37.50	4	
1127	1127 MILLIKEN (Duncan Stewart) Lagrange	Distribution	Unattended	46.00	0.60		3.50	1	
1128	1128 MILLIKEN (Kingsley Mill) Thomson	Distribution	Unattended	115.00	4.00		22.40	1	
1129	1129 MILLIKEN (Lagrange)	Distribution	Unattended	115.00	12.00		22.40	1	
1130	1130 MILLIKEN (Lagrange)	Distribution	Unattended	115.00	12.00		44.80	2	
1131	1131 MILLIKEN (New Holland) Gainesville	Distribution	Unattended	46.00	0.60		7.00	1	
1132	1132 MILLIKEN (New Holland) Gainesville	Distribution	Unattended	46.00	0.60		14.00	2	
1133	1133 MILLIKEN (Pine Mountain)	Distribution	Unattended	25.00	0.60		3.50	1	
1134	1134 MILLIKEN (Pine Mountain)	Distribution	Unattended	25.00	0.60		4.20	1	
1135	1135 MILLIRONS ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1136	1136 MILLIRONS ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
1137	1137 MINOLA DRIVE	Distribution	Unattended	230.00	20.00		120.00	2	
1138	1138 MISSION POND	Distribution	Attended	115.00	34.50		55.00	1	
1139	1139 MITCHELL 115	Transmission	Unattended	115.00	12.00		10.00	1	
1140	1140 MITCHELL 115	Transmission	Unattended	115.00	46.00		25.00	1	
1141	1141 MODULAR CONTAINER SYSTEMS	Distribution	Unattended	46.00	0.48		1.12	1	
1142	1142 MOHAWK INDUSTRIES (East Dublin)	Distribution	Unattended	46.00	12.00		7.00	1	
1143	1143 MOHAWK INDUSTRIES (Lyerly)	Distribution	Unattended	46.00	4.00		7.00	1	
1144	1144 MOHAWK INDUSTRIES (Summerville)	Distribution	Unattended	115.00	25.00		80.00	2	
1145	1145 MOLENA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1146	1146 MOLENA PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1147	1147 MONK ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1148	1148 MONK ROAD	Distribution	Unattended	115.00	12.00		10.50	1	
1149	1149 MONROE INDUSTRIAL PD	Distribution	Unattended	46.00	0.48		2.50	1	
1150	1150 MONTEZUMA	Distribution	Unattended	115.00	12.00		10.50	1	
1151	1151 MONTEZUMA	Distribution	Unattended	115.00	12.00		10.50	1	
1152	1152 MONTGOMERYVILLE	Distribution	Unattended	46.00	12.00		7.00	1	

1153	1153 MORELAND AVENUE	Distribution	Unattended	115.00	20.00		120.00	2	
1154	1154 MORELAND WAY	Distribution	Unattended	115.00	20.00		60.00	1	
1155	1155 MORGAN FALLS	Distribution	Unattended	115.00	20.00		40.00	1	
1156	1156 MORGAN FALLS	Distribution	Unattended	115.00	25.00		56.00	1	
1157	1157 MORGAN FALLS HYDRO	Generation	Attended	20.00	4.00		15.00	2	
1158	1158 MORGAN PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1159	1159 MORGANVILLE	Distribution	Unattended	46.00	12.00		10.50	2	
1160	1160 MORGANVILLE	Distribution	Unattended	161.00	46.00		22.40	1	
1161	1161 MORNINGSIDE	Distribution	Unattended	230.00	20.00		56.00	1	
1162	1162 MOSSY BRANCH BATTERY STORAGE	Generation	Attended	115.00	34.50		75.00	1	
1163	1163 MOULTRIE	Distribution	Unattended	115.00	12.00		10.50	1	
1164	1164 MOULTRIE	Distribution	Unattended	115.00	46.00		25.00	1	
1165	1165 MOULTRIE	Distribution	Unattended	115.00	25.00		40.00	1	
1166	1166 MOULTRIE	Distribution	Unattended	115.00	12.00		10.50	1	
1167	1167 MOUNT VERNON	Distribution	Unattended	115.00	12.00		10.50	1	
1168	1168 MOUNT VERNON MILLS (Alto)	Distribution	Unattended	115.00	12.00		31.50	3	
1169	1169 MOUNT VERNON MILLS (Cleveland)	Distribution	Unattended	25.00	0.60		5.60	2	
1170	1170 MOUNT VERNON MILLS (Trion)	Distribution	Unattended	115.00	12.00		44.80	2	
1171	1171 MOUNTAIN HILL	Distribution	Unattended	115.00	25.00		10.50	1	
1172	1172 MOUNTAIN SPRINGS #1 PM	Distribution	Unattended	46.00	12.00		0.33	1	
1173	1173 MOUNTAIN VIEW	Distribution	Unattended	115.00	20.00		40.00	1	
1174	1174 MOUNTAIN VIEW	Distribution	Unattended	115.00	20.00		50.00	1	
1175	1175 MOUNTAIN VIEW	Distribution	Unattended	115.00	25.00		44.80	2	
1176	1176 MRS. SMITHS BAKERIES	Distribution	Unattended	20.00	0.48		3.50	1	
1177	1177 MRS. SMITHS BAKERIES	Distribution	Unattended	20.00	0.48		3.50	1	
1178	1178 MUD CREEK	Distribution	Unattended	115.00	12.00		22.40	1	
1179	1179 MULKEY ROAD	Distribution	Unattended	115.00	25.00		22.40	1	
1180	1180 MULLITE #2	Distribution	Unattended	115.00	4.00		21.00	2	
1181	1181 MULLITE #2	Distribution	Unattended	115.00	46.00		25.00	1	
1182	1182 MYSTERY VALLEY	Distribution	Unattended	115.00	25.00		120.00	2	
1183	1183 NACOOCHEE	Generation	Attended	46.00			7.00	1	
1184	1184 NACOOCHEE	Generation	Attended	46.00	7.20		0.83	1	
1185	1185 NASHVILLE #1	Distribution	Unattended	115.00	12.00		25.00	1	
1186	1186 NASHVILLE #1	Distribution	Unattended	115.00	12.00		25.00	1	

1187	1187 NASHVILLE MILLS ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
1188	1188 NATIONAL BEEF	Distribution	Unattended	46.00	0.48		2.10	1	
1189	1189 NATIONAL BEEF	Distribution	Unattended	46.00	0.48		2.10	1	
1190	1190 NECO	Distribution	Unattended	115.00	13.80		40.00	1	
1191	1191 NECO	Distribution	Unattended	115.00	13.80		22.40	1	
1192	1192 NEW RIVERSIDE OCHRE	Distribution	Unattended	46.00	2.40		1.50	3	
1193	1193 NEWELL RECYCLING #1 (East Point)	Distribution	Unattended	20.00	4.00		5.00	1	
1194	1194 NEWELL RECYCLING (Norcross)	Transmission	Unattended	115.00	4.00		7.00	1	
1195	1195 NEWTON	Distribution	Unattended	46.00	12.00		4.20	1	
1196	1196 NIPPER PM	Distribution	Unattended	46.00	12.00		0.25	1	
1197	1197 NORDIC COLD STORAGE #2 (Doraville)	Distribution	Unattended	46.00	0.48		1.68	1	
1198	1198 NORDIC COLD STORAGE (Doraville)	Distribution	Unattended	46.00	0.48		3.22	3	
1199	1199 NORDIC COLD STORAGE (Hapeville)	Distribution	Unattended	20.00	0.48		2.00	1	
1200	1200 NORMAN PARK ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1201	1201 NORTH ATHENS	Distribution	Unattended	115.00	12.00		80.00	2	
1202	1202 NORTH AWRF	Distribution	Unattended	115.00	12.00		21.00	2	
1203	1203 NORTH CLARKESVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1204	1204 NORTH COLUMBUS	Distribution	Unattended	115.00	12.00		50.00	2	
1205	1205 NORTH CONYERS	Distribution	Unattended	115.00	12.00		50.00	2	
1206	1206 NORTH DRUID HILLS	Distribution	Unattended	115.00	20.00		50.00	1	
1207	1207 NORTH DRUID HILLS	Distribution	Unattended	115.00	20.00		40.00	1	
1208	1208 NORTH DRUID HILLS	Distribution	Unattended	115.00	20.00		60.00	1	
1209	1209 NORTH FAIRMOUNT	Distribution	Unattended	115.00	12.00		25.00	1	
1210	1210 NORTH FORK	Distribution	Unattended	230.00	20.00		56.00	1	
1211	1211 NORTH GRIFFIN	Distribution	Unattended	115.00	12.00		25.00	1	
1212	1212 NORTH HIGHLANDS	Generation	Attended	12.00	4.00		23.00	1	
1213	1213 NORTH HIGHLANDS	Generation	Attended	12.00	4.00		14.00	1	
1214	1214 NORTH JEFFERSON	Distribution	Unattended	115.00	12.00		25.00	1	
1215	1215 NORTH JEFFERSON	Distribution	Unattended	115.00	46.00		50.00	1	
1216	1216 NORTH JEFFERSON	Distribution	Unattended	115.00	25.00		25.00	1	
1217	1217 NORTH KEITHSBURG	Distribution	Unattended	115.00	25.00		67.20	2	
1218	1218 NORTH KITE	Distribution	Unattended	46.00	12.00		5.25	1	
1219	1219 NORTH MACON	Distribution	Unattended	115.00	12.00		44.80	2	
1220	1220 NORTH MARTIN	Distribution	Unattended	115.00	12.00		10.50	1	

1221	1221 NORTH MCRAE	Distribution	Unattended	46.00	12.00		10.50	1	
1222	1222 NORTH METTER	Distribution	Unattended	46.00	12.00		6.25	1	
1223	1223 NORTH MILLEDGEVILLE	Distribution	Unattended	115.00	12.00		50.00	2	
1224	1224 NORTH MONTICELLO	Transmission	Unattended	230.00	69.00	13	60.00	1	
1225	1225 NORTH OCONEE WRF	Distribution	Unattended	115.00	12.00		10.50	1	
1226	1226 NORTH RIVERSIDE	Distribution	Unattended	115.00	12.00		80.00	2	
1227	1227 NORTH ROCKMART	Distribution	Unattended	115.00	12.00		33.60	1	
1228	1228 NORTH SHALLOWFORD ROAD	Distribution	Unattended	115.00	20.00		60.00	1	
1229	1229 NORTH SPRINGS	Distribution	Unattended	230.00	20.00		56.00	1	
1230	1230 NORTH STATESBORO	Distribution	Unattended	115.00	12.00		22.40	1	
1231	1231 NORTH STATESBORO	Distribution	Unattended	115.00	12.00		25.00	1	
1232	1232 NORTH THOMASTON	Distribution	Unattended	115.00	12.00		25.00	1	
1233	1233 NORTH THOMSON	Distribution	Unattended	46.00	12.00		5.25	1	
1234	1234 NORTH THOMSON	Distribution	Unattended	46.00	25.00		14.00	2	
1235	1235 NORTH TIFTON	Transmission	Unattended	500.00				3	
1236	1236 NORTH TIFTON	Transmission	Unattended	115.00	12.00		25.00	1	
1237	1237 NORTH VALDOSTA	Distribution	Unattended	115.00	12.00		22.40	1	
1238	1238 NORTH VALDOSTA	Distribution	Unattended	115.00	12.00		40.00	1	
1239	1239 NORTHCREST	Distribution	Unattended	115.00	12.00		25.00	1	
1240	1240 NORTHEAST WAYCROSS	Distribution	Unattended	115.00	12.00		44.80	2	
1241	1241 NORTHPARK	Distribution	Unattended	230.00	20.00		112.00	2	
1242	1242 NORTHPARK	Distribution	Unattended	230.00	20.00		60.00	1	
1243	1243 NORTHSIDE DRIVE	Distribution	Unattended	115.00	20.00		60.00	1	
1244	1244 NORTHSIDE DRIVE	Distribution	Unattended	115.00	20.00		50.00	1	
1245	1245 NORTHWEST 115	Distribution	Unattended	115.00	20.00		120.00	2	
1246	1246 NORTHWEST 230	Transmission	Unattended	230.00	115.00	13	400.00	1	
1247	1247 NORTHWEST 230	Transmission	Unattended	230.00	115.00		400.00	1	
1248	1248 NORTHWEST PERRY	Distribution	Unattended	115.00	12.00		22.40	1	
1249	1249 NORTHWEST WAYCROSS	Distribution	Unattended	25.00	12.00		7.00	1	
1250	1250 NORTHWEST WAYCROSS	Distribution	Unattended	115.00	12.00		21.00	2	
1251	1251 NORTHWEST WAYCROSS	Distribution	Unattended	115.00	12.00		10.50	1	
1252	1252 NORTHWINDS	Distribution	Unattended	230.00	25.00		60.00	1	
1253	1253 NOWHERE ROAD PM	Distribution	Unattended	46.00	12.00			1	
1254	1254 NUTRASWEET	Distribution	Unattended	115.00	13.80		22.40	1	
1255	1255 NUTRASWEET	Distribution	Unattended	115.00	13.80		10.50	1	

1256	1256 OAK GROVE	Distribution	Unattended	115.00	25.00		33.60	1	
1257	1257 OAK GROVE	Distribution	Unattended	115.00	25.00		40.00	1	
1258	1258 OAK STREET	Distribution	Unattended	115.00	12.00		44.80	2	
1259	1259 OAK STREET	Distribution	Unattended	115.00	12.00		33.00	1	
1260	1260 OAKEY WOODS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1261	1261 OAKFIELD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1262	1262 OCEAN HIGHWAY	Distribution	Unattended	115.00	12.00		25.00	1	
1263	1263 OCHLOCKNEE	Distribution	Unattended	46.00	12.00		5.25	1	
1264	1264 OCHLOCKNEE PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1265	1265 OCMULGEE STREET	Distribution	Unattended	115.00	12.00		80.00	2	
1266	1266 OCONEE PD	Distribution	Unattended	46.00	12.00		2.50	1	
1267	1267 OGLETHORPE MALL	Distribution	Unattended	115.00	13.80		50.00	2	
1268	1268 OHOOPEE RIVER	Distribution	Unattended	115.00	12.00		21.00	2	
1269	1269 OLD ALABAMA ROAD	Distribution	Unattended	230.00	25.00		56.00	1	
1270	1270 OLD ALABAMA ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
1271	1271 OLD ALABAMA ROAD	Distribution	Unattended	230.00	12.00		67.20	2	
1272	1272 OLD DALTON ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1273	1273 OLD HICKORY	Distribution	Unattended	115.00	12.00		80.00	2	
1274	1274 OLD MAUK ROAD	Distribution	Unattended	46.00	12.00		10.50	1	
1275	1275 OLD NATIONAL	Distribution	Unattended	115.00	25.00		56.00	1	
1276	1276 OLD RIVER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1277	1277 OLD SAVANAH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1278	1278 OLIN	Distribution	Unattended	115.00	13.80		10.50	1	
1279	1279 OLIVER DAM HYDRO	Generation	Attended	115.00	7.20		30.00	1	
1280	1280 OLIVER DAM HYDRO	Generation	Attended	115.00	7.20		45.00	2	
1281	1281 OLIVER ROAD	Distribution	Unattended	115.00	12.00		33.60	1	
1282	1282 OPHELIA SMITH PM	Distribution	Unattended					1	
1283	1283 ORANGE	Distribution	Unattended	115.00	25.00		45.06	1	
1284	1284 ORANGE	Distribution	Unattended	115.00	25.00		35.87	1	
1285	1285 ORANGE HILL	Distribution	Unattended	115.00	12.00		25.00	1	
1286	1286 ORCHARD HILL	Distribution	Unattended	69.00	12.00		5.25	1	
1287	1287 OVERLAND TRAIL LAND PM	Distribution	Unattended	46.00	12.00		0.25	1	
1288	1288 OWENS CORNING FIBERGLASS	Distribution	Unattended	115.00	12.00		44.80	2	
1289	1289 OWENS ILLINOIS (Hamilton Boulevard)	Distribution	Unattended	20.00	0.48		2.58	2	
1290	1290 OWL HEAD #2	Distribution	Unattended	46.00	12.00		0.25	1	

1291	1291 OXFORD ROAD	Distribution	Unattended	115.00	20.00		53.20	1	
1292	1292 PACES FERRY	Distribution	Unattended	115.00	20.00		60.00	1	
1293	1293 PACKAGING CORPORATION (Clyattville)	Distribution	Unattended	69.00	4.00		50.00	2	
1294	1294 PACKAGING CORPORATION (Macon)	Distribution	Unattended	12.00	0.48		3.50	1	
1295	1295 PACKAGING CORPORATION (Macon)	Distribution	Unattended	12.00	0.48		3.50	1	
1296	1296 PACTIV #2	Distribution	Unattended	46.00	0.48		1.68	1	
1297	1297 PACTIV #2	Distribution	Unattended	46.00	0.48		2.80	1	
1298	1298 PACTIV #3 PD	Distribution	Unattended	46.00	0.48		2.50	1	
1299	1299 PACTIV #4 PD	Distribution	Unattended	46.00	0.48		2.50	1	
1300	1300 PACTIV #6	Distribution	Unattended	46.00	0.48		10.50	3	
1301	1301 PACTIV #7	Distribution	Unattended	46.00	0.48		5.60	2	
1302	1302 PALM STREET	Distribution	Unattended	115.00	25.00		45.80	2	
1303	1303 PALM STREET	Distribution	Unattended	115.00	25.00		25.00	1	
1304	1304 PALMER CREEK	Distribution	Unattended	230.00	25.00		25.00	1	
1305	1305 PALMYRA	Distribution	Unattended	115.00	12.00		25.00	1	
1306	1306 PALMYRA	Distribution	Unattended	115.00	25.00		25.00	1	
1307	1307 PARK	Distribution	Unattended	20.00	12.00		25.00	1	
1308	1308 PARK	Distribution	Unattended	115.00	20.00		60.00	1	
1309	1309 PARKDALE	Distribution	Unattended	115.00	12.00		22.40	1	
1310	1310 PARKDALE	Distribution	Unattended	115.00	12.00		25.00	1	
1311	1311 PARKENSON CHURCH ROAD PM	Distribution	Unattended	46.00	12.00		0.50	2	
1312	1312 PARKENSON CHURCH ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1313	1313 PARKWAY	Distribution	Unattended	115.00	12.00		67.20	2	
1314	1314 PASCOE STEEL	Distribution	Unattended	12.00	0.48		1.50	1	
1315	1315 PATRIOTS PARK	Distribution	Unattended	115.00	12.00		50.00	2	
1316	1316 PATTON SEED PM	Distribution	Unattended	46.00	12.00		0.25	1	
1317	1317 PATTON SEED PM	Distribution	Unattended	46.00	12.00		0.50	2	
1318	1318 PCS NITROGEN	Distribution	Unattended	115.00	13.80		100.00	2	
1319	1319 PEACH ORCHARD	Distribution	Unattended	230.00	12.00		22.40	1	
1320	1320 PEACH ORCHARD	Distribution	Unattended	230.00	12.00		25.00	1	
1321	1321 PEACH ORCHARD	Distribution	Unattended	13.80	12.00		25.00	1	
1322	1322 PEACHTREE	Distribution	Unattended	230.00	20.00		180.00	3	
1323	1323 PEACHTREE	Distribution	Unattended	230.00	20.00		56.00	1	
1324	1324 PEACHTREE CITY #2	Distribution	Unattended	115.00	12.00		44.80	2	

1325	1325 PEACHTREE CORNERS	Distribution	Unattended	230.00	25.00		56.00	1	
1326	1326 PEACHTREE CORNERS	Distribution	Unattended	230.00	25.00		60.00	1	
1327	1327 PEARL STREET	Distribution	Unattended	46.00	12.00		10.50	1	
1328	1328 PEARSON	Distribution	Unattended	115.00	12.00		7.00	1	
1329	1329 PEEPLES VALLEY	Distribution	Unattended	115.00	25.00		40.00	1	
1330	1330 PEEPLES VALLEY	Distribution	Unattended	115.00	25.00		60.00	1	
1331	1331 PELHAM	Distribution	Unattended	46.00	12.00		10.50	2	
1332	1332 PEMBROKE	Distribution	Unattended	115.00	25.00		25.00	1	
1333	1333 PENN CAMP ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1334	1334 PERIMETER CENTER	Distribution	Unattended	230.00	20.00		168.00	3	
1335	1335 PERRY	Transmission	Unattended	115.00	12.00		44.80	2	
1336	1336 PERRY	Transmission	Unattended	115.00	46.00		25.00	1	
1337	1337 PERRY	Transmission	Unattended	115.00	12.00		10.50	1	
1338	1338 PERRY PARKWAY	Distribution	Unattended	115.00	25.00		25.00	1	
1339	1339 PETERSBURG ROAD	Distribution	Unattended	115.00	12.00		10.50	1	
1340	1340 PETERSON CREEK	Distribution	Unattended	115.00	12.00		7.00	1	
1341	1341 PETTIT CREEK	Distribution	Unattended	115.00	12.00		33.30	1	
1342	1342 PETTIT CREEK	Distribution	Unattended	115.00	46.00		56.00	1	
1343	1343 PHARMATECH	Distribution	Unattended	46.00	0.48		4.69	1	
1344	1344 PHARMATECH	Distribution	Unattended	46.00	0.48		3.50	1	
1345	1345 PHILEMA ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1346	1346 PILGRIMS PRIDE #1 (Athens)	Distribution	Unattended	46.00	0.48		1.93	1	
1347	1347 PILGRIMS PRIDE #1 (Athens)	Distribution	Unattended	46.00	0.48		3.50	1	
1348	1348 PILGRIMS PRIDE #2 (Athens)	Distribution	Unattended	46.00	0.48		7.00	1	
1349	1349 PILGRIMS PRIDE #3 (Athens)	Distribution	Unattended	12.00	0.48		2.80	1	
1350	1350 PILGRIMS PRIDE (Canton)	Distribution	Unattended	25.00	0.48		7.00	2	
1351	1351 PILGRIMS PRIDE (Industrial Boulevard)	Distribution	Unattended	46.00	12.00		7.00	1	
1352	1352 PINE GROVE PRIMARY	Transmission	Unattended	115.00	25.00		40.00	1	
1353	1353 PINE GROVE PRIMARY	Transmission	Unattended	230.00	115.00		400.00	1	
1354	1354 PINE MOUNTAIN	Distribution	Unattended	115.00	25.00		44.80	2	
1355	1355 PINSON	Distribution	Unattended	115.00	12.00		22.40	1	
1356	1356 PINSON	Distribution	Unattended	115.00	25.00		44.80	2	
1357	1357 PITTMAN ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1358	1358 PITTS CHAPEL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	

1359	1359 PLAINS	Distribution	Unattended	46.00	12.00		5.25	1	
1360	1360 PLANTATION PIPELINE (Austell)	Distribution	Unattended	115.00	4.00		11.20	2	
1361	1361 PLANTATION PIPELINE (Bremen)	Distribution	Unattended	115.00	4.00		44.80	2	
1362	1362 PLANTATION PIPELINE (Doraville)	Distribution	Unattended	46.00	4.00		6.25	1	
1363	1363 PLANTATION PIPELINE (Lafayette)	Distribution	Unattended	20.00	2.40		3.00	6	
1364	1364 PLANTATION PIPELINE (Neese)	Distribution	Unattended	115.00	4.00		21.00	2	
1365	1365 PLANTATION PIPELINE (Subligna)	Distribution	Unattended	46.00	2.40		2.50	3	
1366	1366 PLANTATION ROAD	Distribution	Unattended	115.00	25.00		56.00	1	
1367	1367 PLEASANTDALE ROAD	Distribution	Unattended	230.00	25.00		120.00	2	
1368	1368 POLYCHROME	Distribution	Unattended	25.00	12.00		22.40	1	
1369	1369 POMONA	Distribution	Unattended	115.00	25.00		25.00	1	
1370	1370 POMONA	Distribution	Unattended	115.00	12.00		22.40	1	
1371	1371 PONCE DE LEON	Distribution	Unattended	115.00	25.00		56.00	1	
1372	1372 PONCE DE LEON	Distribution	Unattended	115.00	25.00		40.00	1	
1373	1373 POOLER	Distribution	Unattended	46.00	13.80		10.50	1	
1374	1374 POOLER	Distribution	Unattended	46.00	13.80		28.00	2	
1375	1375 PORTER PD	Distribution	Unattended	46.00	12.00		5.00	1	
1376	1376 PORTERDALE PRIMARY	Distribution	Unattended	115.00	25.00		10.50	1	
1377	1377 PORTERDALE PRIMARY	Distribution	Unattended	115.00	25.00		40.00	1	
1378	1378 PORTERDALE PRIMARY	Distribution	Unattended	46.00	12.00	7	10.50	1	
1379	1379 PORTERDALE PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1380	1380 PORTLAND	Transmission	Unattended	115.00	46.00		50.00	1	
1381	1381 POTTERVILLE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1382	1382 POTTERY OUTLET PD (RETIRED)	Distribution	Unattended	46.00	12.00		2.50	1	
1383	1383 POULAN	Distribution	Unattended	46.00	12.00		1.25	1	
1384	1384 POULAN	Distribution	Unattended	46.00	12.00		1.67	2	
1385	1385 POWDER SPRINGS	Distribution	Unattended	115.00	25.00		33.60	1	
1386	1386 POWDER SPRINGS	Distribution	Unattended	115.00	12.00		33.60	1	
1387	1387 POWER LINE ROAD	Distribution	Unattended	115.00	13.80		10.50	1	
1388	1388 POWER PARTNERS	Distribution	Unattended	46.00	4.00		3.75	1	
1389	1389 POWER PARTNERS	Distribution	Unattended	46.00	4.00		5.25	1	
1390	1390 POWERS FERRY	Distribution	Unattended	230.00	20.00		240.00	4	
1391	1391 PPG INDUSTRIES	Distribution	Unattended	115.00	12.00		10.50	1	

1392	1392 PRATT & WHITNEY	Distribution	Unattended	115.00	13.80		44.80	2	
1393	1393 PRAYON	Distribution	Unattended	13.80	4.00		2.80	1	
1394	1394 PREFERRED COMPOUNDING #1 PD	Distribution	Unattended	46.00	0.48		2.50	1	
1395	1395 PREFERRED COMPOUNDING #2 PM	Distribution	Unattended	46.00	4.00		0.75	3	
1396	1396 PREFERRED COMPOUNDING #4 PD	Distribution	Unattended	46.00	4.00		2.50	1	
1397	1397 PRESIDENT STREET SEWAGE	Distribution	Unattended	46.00	4.00		21.00	2	
1398	1398 PRESTON	Distribution	Unattended	46.00	12.00		4.20	1	
1399	1399 PRINGLE ROAD	Distribution	Unattended	46.00	12.00		7.00	1	
1400	1400 PROCTER & GAMBLE (Albany)	Distribution	Unattended	115.00	13.80		60.00	1	
1401	1401 PROCTER & GAMBLE (Albany)	Distribution	Unattended	115.00	13.80		93.33	2	
1402	1402 PROFILE EXTRUSIONS PD	Distribution	Unattended	46.00	0.48		3.50	1	
1403	1403 PROPEX #1 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1404	1404 PROPEX #1 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1405	1405 PROPEX #10 (Hazlehurst)	Distribution	Unattended	46.00	0.48		7.00	2	
1406	1406 PROPEX #11 (Hazlehurst)	Distribution	Unattended	46.00	0.48		1.68	1	
1407	1407 PROPEX #2 (Hazlehurst)	Distribution	Unattended	46.00	0.48		5.04	3	
1408	1408 PROPEX #3 (Hazlehurst)	Distribution	Unattended	46.00	0.48		5.60	2	
1409	1409 PROPEX #4 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1410	1410 PROPEX #4 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1411	1411 PROPEX #4 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1412	1412 PROPEX #5 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.80	1	
1413	1413 PROPEX #5 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1414	1414 PROPEX #6 (Hazlehurst)	Distribution	Unattended	46.00	0.48		2.10	1	
1415	1415 PROPEX #7 (Hazlehurst)	Distribution	Unattended	46.00	0.48		3.50	1	
1416	1416 PROPEX #7 (Hazlehurst)	Distribution	Unattended	46.00	0.48		4.20	1	
1417	1417 PUBLIC SAFETY TRAINING CENTER	Distribution	Unattended	115.00	12.00		6.25	1	
1418	1418 PULASKI	Distribution	Unattended	46.00	12.00		3.75	3	
1419	1419 PULASKI SEWAGE PM	Distribution	Unattended	46.00	12.00		0.75	3	
1420	1420 PURCELL ROAD	Distribution	Unattended	230.00	25.00		60.00	1	
1421	1421 PUTNAM PM	Distribution	Unattended	46.00	12.00		0.25	1	
1422	1422 PYRAMAX CERAMICS	Distribution	Unattended	46.00	25.00		10.50	1	
1423	1423 QUACCO ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
1424	1424 QUACCO ROAD	Distribution	Unattended	115.00	13.80		33.30	1	
1425	1425 QUAIL HOLLOW PM	Distribution	Unattended	46.00	12.00		0.25	1	

1426	1426 QUAIL RIDGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1427	1427 QUINTON DILLINGHAM PM	Distribution	Unattended	46.00	12.00		0.25	1	
1428	1428 R. M. MOORE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1429	1429 RADIUM SPRINGS	Distribution	Unattended	115.00	12.00		22.40	1	
1430	1430 RAGLAND STREET	Distribution	Unattended	115.00	12.00		22.40	1	
1431	1431 RAINBOW DRIVE	Distribution	Unattended	115.00	20.00		40.00	1	
1432	1432 RAINBOW DRIVE	Distribution	Unattended	115.00	20.00		60.00	1	
1433	1433 RALSTON PURINA MILLS (Gainesville)	Distribution	Unattended	46.00	0.48		3.50	1	
1434	1434 RANDALL	Distribution	Unattended	46.00	12.00		10.50	1	
1435	1435 RAY MOUNTAIN PM	Distribution	Unattended	46.00	12.00		0.25	1	
1436	1436 RAYONIER (Eatonton)	Distribution	Unattended	46.00	12.00		5.25	1	
1437	1437 RAYONIER (Jesup)	Distribution	Unattended	115.00	13.80		40.00	1	
1438	1438 RAYONIER (Jesup)	Distribution	Unattended	115.00	13.80		33.60	1	
1439	1439 REBECCA	Distribution	Unattended	46.00	12.00		1.50	3	
1440	1440 RED DOG FARM ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1441	1441 RED TOP MOUNTAIN	Distribution	Unattended	115.00	12.00		25.00	1	
1442	1442 RED TOP MOUNTAIN	Distribution	Unattended	115.00	46.00		25.00	1	
1443	1443 REDMOND CIRCLE	Distribution	Unattended	115.00	12.00		25.00	1	
1444	1444 REDMOND CIRCLE	Distribution	Unattended	115.00	12.00		25.00	1	
1445	1445 REFUGE ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1446	1446 REIDS	Distribution	Unattended	46.00	12.00		6.25	1	
1447	1447 REIDS PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1448	1448 REIDSVILLE	Distribution	Unattended	115.00	25.00		10.00	1	
1449	1449 REIDSVILLE	Distribution	Unattended	115.00	12.00		22.40	1	
1450	1450 REMERTON	Distribution	Unattended	115.00	12.00		44.80	2	
1451	1451 REMLERS CORNER	Distribution	Unattended	46.00	13.80		22.40	1	
1452	1452 REMLERS CORNER	Distribution	Unattended	46.00	13.80		20.00	1	
1453	1453 REMLERS CORNER	Distribution	Unattended	46.00	13.80		25.00	1	
1454	1454 REST HAVEN	Distribution	Unattended	115.00	25.00		10.50	1	
1455	1455 REST HAVEN	Distribution	Unattended	115.00	25.00		25.00	1	
1456	1456 RETTCO STEEL	Distribution	Unattended	46.00	0.48		7.00	2	
1457	1457 REYNOLDS	Distribution	Unattended	46.00	12.00		5.25	1	
1458	1458 RHINE PD	Distribution	Unattended	46.00	12.00		5.00	1	
1459	1459 RICE CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1460	1460 RICHARDSON STREET	Distribution	Unattended	115.00	12.00		22.40	1	
1461	1461 RICHMOND HILL	Distribution	Unattended	115.00	13.80		44.80	2	

1462	1462 RIDGEWAY CHURCH ROAD	Distribution	Unattended	115.00	12.00		120.00	2	
1463	1463 RINGGOLD	Distribution	Unattended	115.00	25.00		25.00	1	
1464	1464 RINGGOLD	Distribution	Unattended	115.00	12.00		22.40	1	
1465	1465 RISING FAWN	Distribution	Unattended	46.00	12.00		4.69	1	
1466	1466 RITE AID (Newnan)	Distribution	Unattended	46.00	0.48		3.50	1	
1467	1467 RIVER PARK	Distribution	Unattended	115.00	25.00		40.00	1	
1468	1468 RIVER ROAD	Distribution	Unattended	25.00	20.00		6.25	1	
1469	1469 RIVER ROAD	Distribution	Unattended	115.00	20.00		45.89	1	
1470	1470 RIVER STREET	Distribution	Unattended	46.00	13.80		120.00	3	
1471	1471 RIVERDALE	Distribution	Unattended	115.00	25.00		60.00	1	
1472	1472 RIVERDALE	Distribution	Unattended	115.00	25.00		40.00	1	
1473	1473 RIVERSIDE MILLS	Distribution	Unattended	46.00	4.00		14.00	2	
1474	1474 RIVERSTONE	Distribution	Unattended	115.00	25.00		40.00	1	
1475	1475 RIVERVIEW HYDRO	Generation	Attended	12.00	2.40		2.00	6	
1476	1476 RIVERWOOD #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1477	1477 RIVERWOOD #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1478	1478 ROBERTS ROAD	Distribution	Unattended	115.00	25.00		40.00	1	
1479	1479 ROBERTS ROAD	Distribution	Unattended	115.00	12.00		22.40	1	
1480	1480 ROBERTS ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
1481	1481 ROBINS AFB #1	Distribution	Unattended	115.00	12.00		89.60	4	
1482	1482 ROBINS AFB #2	Distribution	Unattended	115.00	12.00		44.80	2	
1483	1483 ROBINS AFB #2	Distribution	Unattended	115.00	12.00		25.00	1	
1484	1484 ROBINS AFB #3	Distribution	Unattended	12.00	4.00		7.00	1	
1485	1485 ROBINS AFB #4 - W.D. Fowler	Distribution	Unattended	115.00	12.00		40.00	1	
1486	1486 ROBINS AFB #4 - W.D. Fowler	Distribution	Unattended	115.00	12.00		25.00	1	
1487	1487 ROBINS AFB SOLAR (IC-491)	Generation	Attended	115.00	34.50		145.00	1	
1488	1488 ROBINS CT	Generation	Attended	115.00	13.80		220.00	1	
1489	1489 ROCHELLE	Distribution	Unattended	46.00	12.00		7.00	1	
1490	1490 ROCHELLE	Distribution	Unattended	46.00	12.00		7.00	1	
1491	1491 ROCKBRIDGE ROAD	Distribution	Unattended	230.00	12.00		40.00	1	
1492	1492 ROCKMART	Distribution	Unattended	46.00	12.00		15.75	3	
1493	1493 ROCKY FORD ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
1494	1494 ROGERS LANDING PM	Distribution	Unattended	46.00	12.00		0.25	1	
1495	1495 ROME	Distribution	Unattended	115.00	12.00		22.40	1	
1496	1496 ROME	Distribution	Unattended	115.00	12.00		40.00	1	
1497	1497 ROOPVILLE	Distribution	Unattended	230.00	12.00		25.00	1	

1498	1498 ROPER INDUSTRIES #2 (RETIRED)	Distribution	Unattended	25.00	0.48		3.50	1	
1499	1499 ROPER INDUSTRIES (RETIRED)	Distribution	Unattended	25.00	0.48		3.50	1	
1500	1500 ROPERS CORNER	Distribution	Unattended	115.00	12.00		66.66	2	
1501	1501 ROSSIGNOL HILL	Distribution	Unattended	46.00	13.80		22.40	1	
1502	1502 ROSSIGNOL HILL	Distribution	Unattended	46.00	13.80		20.00	1	
1503	1503 ROSSMAN PM	Distribution	Unattended	46.00	12.00		0.25	1	
1504	1504 ROSWELL	Distribution	Unattended	115.00	25.00		56.00	1	
1505	1505 ROSWELL	Distribution	Unattended	115.00	25.00		60.00	1	
1506	1506 ROTTENWOOD CREEK	Distribution	Unattended	115.00	20.00		120.00	2	
1507	1507 ROYAL ATLANTA	Distribution	Unattended	230.00	25.00		60.00	1	
1508	1508 ROYSTON	Distribution	Unattended	46.00	12.00		6.25	1	
1509	1509 ROYSTON	Distribution	Unattended	46.00	12.00		6.25	1	
1510	1510 ROYSTON MANUFACTURING	Distribution	Unattended	46.00	0.48		2.10	1	
1511	1511 RUCKER BROTHERS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1512	1512 RUSSELL AREA PM Retired	Distribution	Unattended	46.00	12.00		0.25	1	
1513	1513 SAGE AUTOMOTIVE INTERIORS	Distribution	Unattended	115.00	0.60		14.00	2	
1514	1514 SAINT MARYS	Distribution	Unattended	115.00	12.00		25.00	1	
1515	1515 SAINT MARYS ROAD	Distribution	Unattended	115.00	46.00		60.00	1	
1516	1516 SAINT MARYS ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
1517	1517 SAINT SIMONS	Distribution	Unattended	115.00	12.00		22.40	1	
1518	1518 SAINT SIMONS	Distribution	Unattended	115.00	12.00		25.00	1	
1519	1519 SALE CITY	Distribution	Unattended	46.00	12.00		5.25	1	
1520	1520 SALEM GATE	Distribution	Unattended	115.00	12.00		33.60	1	
1521	1521 SANDERSON FARMS	Distribution	Unattended	46.00	25.00		10.50	1	
1522	1522 SANDERSVILLE CLAY	Distribution	Unattended	46.00	0.48		2.50	3	
1523	1523 SANDY BOTTOM	Distribution	Unattended	115.00	12.00		10.50	1	
1524	1524 SANDY SPRINGS	Distribution	Unattended	230.00	20.00		56.00	1	
1525	1525 SAPA EXTRUDER	Distribution	Unattended	46.00	0.48		3.50	1	
1526	1526 SAPA EXTRUDER	Distribution	Unattended	46.00	0.48		4.69	1	
1527	1527 SARDIS	Distribution	Unattended	115.00	12.00		21.00	2	
1528	1528 SARGENT	Distribution	Unattended	46.00	12.00		14.00	2	
1529	1529 SASSER	Distribution	Unattended	46.00	12.00		2.00	3	
1530	1530 SATILLA CREEK	Distribution	Unattended	115.00	12.00		7.00	1	
1531	1531 SAULTER PM	Distribution	Unattended	46.00	12.00		0.25	1	

1532	1532 SAVANNAH FOODS	Distribution	Unattended	46.00	4.00		10.50	1	
1533	1533 SCHERER COMMON FACILITIES	Generation	Attended	500.00				3	
1534	1534 SCHERER CONSTRUCTION	Distribution	Attended	115.00	12.00		21.00	2	
1535	1535 SCHERER FGD 1/2	Generation	Attended	115.00	13.80		300.00	4	
1536	1536 SCHERER FGD 3/4	Generation	Attended	115.00	13.80		300.00	4	
1537	1537 SCHERER FGD 3/4	Generation	Attended	115.00	12.00		25.00	1	
1538	1538 SCHERER FGD 3/4	Generation	Attended	115.00	4.00		25.00	1	
1539	1539 SCHERER RIVER PUMPING	Distribution	Attended	115.00	4.00		11.20	2	
1540	1540 SCHERER UNIT 1	Generation	Attended	500.00	25.00		327.00	1	
1541	1541 SCHERER UNIT 1	Generation	Attended	500.00	25.00		584.00	2	
1542	1542 SCHERER UNIT 1	Generation	Attended	25.00	4.16		224.00	4	
1543	1543 SCHERER UNIT 2	Generation	Attended	25.00	4.16		224.00	4	
1544	1544 SCHERER UNIT 2	Generation	Attended	500.00	25.00		876.00	3	
1545	1545 SCHERER UNIT 3	Generation	Attended	25.00	4.16	7	56.00	1	
1546	1546 SCHERER UNIT 3	Generation	Attended	25.00	4.16	4	56.00	1	
1547	1547 SCHERER UNIT 3	Generation	Attended	500.00	25.00		876.00	3	
1548	1548 SCHERER UNIT 4	Generation	Attended	500.00	25.00		981.00	3	
1549	1549 SCHERER UNIT 4	Generation	Attended	25.00	4.16		112.00	2	
1550	1550 SCHERER UNIT 4	Generation	Attended	25.00	4.16		33.60	1	
1551	1551 SCOTT HUDGENS BUILDING	Distribution	Unattended	20.00	0.48		1.12	1	
1552	1552 SCOTTDALE	Distribution	Unattended	115.00	20.00		56.00	1	
1553	1553 SCOTTDALE	Distribution	Unattended	115.00	20.00		60.00	1	
1554	1554 SCOVILLE MANUFACTURING	Distribution	Unattended	46.00	0.48		4.48	2	
1555	1555 SCOVILLE MANUFACTURING	Distribution	Unattended	46.00	0.48		2.15	1	
1556	1556 SEA ISLAND	Distribution	Unattended	115.00	12.00		22.40	1	
1557	1557 SEALY PM	Distribution	Unattended	46.00	12.00		0.25	1	
1558	1558 SEARS FASHION CENTER 25/4 KV	Distribution	Unattended	25.00	4.00		2.80	1	
1559	1559 SEVENTH AVENUE	Distribution	Unattended	115.00	12.00		22.40	1	
1560	1560 SEVENTH AVENUE	Distribution	Unattended	115.00	25.00		80.00	2	
1561	1561 SEWELL ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1562	1562 SHARON PD	Distribution	Unattended	46.00	12.00		2.50	1	
1563	1563 SHAW INDUSTRIES #2 PD (Trenton)	Distribution	Unattended	46.00			5.00	1	
1564	1564 SHAW INDUSTRIES (Milledgeville)	Distribution	Unattended	12.00	0.48		3.50	1	
1565	1565 SHAW INDUSTRIES (Milledgeville)	Distribution	Unattended	12.00	0.48		2.80	1	

1566	1566 SHAW INDUSTRIES (Thomson)	Distribution	Unattended	115.00	4.00		37.50	4	
1567	1567 SHAW INDUSTRIES (Thomson)	Distribution	Unattended	115.00	4.00		22.40	1	
1568	1568 SHENANDOAH SEWAGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1569	1569 SHENANDOAH SEWAGE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1570	1570 SHILOH	Distribution	Unattended	115.00	25.00		21.00	2	
1571	1571 SHUGART FARMS	Distribution	Unattended	230.00	25.00		120.00	2	
1572	1572 SHURLING DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
1573	1573 SHURLING DRIVE	Distribution	Unattended	115.00	12.00		40.00	2	
1574	1574 SILGAN PLASTICS	Distribution	Unattended	46.00	4.00		5.00	1	
1575	1575 SILK HOPE	Distribution	Unattended	46.00	13.80		25.00	1	
1576	1576 SIMPSON LUMBER	Distribution	Unattended	46.00	13.80		7.00	1	
1577	1577 SINCLAIR DAM HYDRO	Generation	Attended	115.00	6.60		50.00	2	
1578	1578 SINCLAIR DAM HYDRO	Generation	Attended	6.60	0.60		1.00	2	
1579	1579 SIX MILE	Distribution	Unattended	115.00	25.00		44.80	2	
1580	1580 SIX MILE	Distribution	Unattended	115.00	12.00		10.50	1	
1581	1581 SKIDAWAY ISLAND	Distribution	Unattended	115.00	25.00		25.00	1	
1582	1582 SKIDAWAY ISLAND	Distribution	Unattended	115.00	25.00		67.20	2	
1583	1583 SLAPPEY DRIVE	Distribution	Unattended	115.00	12.00		44.80	2	
1584	1584 SMITHVILLE	Distribution	Unattended	115.00	25.00		10.50	1	
1585	1585 SMITHVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1586	1586 SMITHVILLE	Distribution	Unattended	115.00	46.00		25.00	1	
1587	1587 SMYRNA	Distribution	Unattended	115.00	20.00		50.00	1	
1588	1588 SMYRNA	Distribution	Unattended	115.00	20.00		50.00	1	
1589	1589 SNAPFINGER ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
1590	1590 SOCIAL CIRCLE	Distribution	Unattended	46.00	12.00		5.25	1	
1591	1591 SOCIAL CIRCLE	Distribution	Unattended	46.00	12.00		7.00	1	
1592	1592 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	115.00	46.00		22.40	1	
1593	1593 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	46.00	12.00		14.00	2	
1594	1594 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1595	1595 SOCIAL CIRCLE PRIMARY	Distribution	Unattended	115.00	25.00		10.00	1	
1596	1596 SOLO CUP #1	Distribution	Unattended	46.00	0.48		3.50	1	
1597	1597 SOLO CUP #1	Distribution	Unattended	46.00	0.48		7.00	1	
1598	1598 SOLO CUP #1	Distribution	Unattended	46.00	0.48		5.25	1	
1599	1599 SOLVAY ADVANCED POLYMERS	Distribution	Unattended	115.00	13.80		80.00	2	

1600	1600 SOPERTON PRIMARY	Distribution	Unattended	115.00	12.00		10.50	1	
1601	1601 SOUTH ADEL	Distribution	Unattended	115.00	12.00		25.00	1	
1602	1602 SOUTH ADEL	Distribution	Unattended	115.00	12.00		22.40	1	
1603	1603 SOUTH ATHENS	Distribution	Unattended	115.00	12.00		33.60	1	
1604	1604 SOUTH AUGUSTA	Transmission	Unattended	115.00	13.80		33.60	1	
1605	1605 SOUTH AUGUSTA	Transmission	Unattended	115.00	13.80		25.00	1	
1606	1606 SOUTH CHATTOOGA	Transmission	Unattended	115.00	46.00		25.00	1	
1607	1607 SOUTH CHATTOOGA	Transmission	Unattended	46.00	12.00		10.50	1	
1608	1608 SOUTH CLEVELAND	Distribution	Unattended	115.00	25.00		10.50	1	
1609	1609 SOUTH COBB DRIVE	Distribution	Unattended	115.00	20.00		80.00	2	
1610	1610 SOUTH COLUMBUS	Distribution	Unattended	115.00	12.00		25.00	1	
1611	1611 SOUTH DAHLONEGA	Distribution	Unattended	115.00	25.00		25.00	1	
1612	1612 SOUTH EFFINGHAM	Distribution	Unattended	115.00	13.80		33.60	1	
1613	1613 SOUTH GAINESVILLE	Distribution	Unattended	115.00	12.00		40.00	1	
1614	1614 SOUTH GAINESVILLE	Distribution	Unattended	115.00	46.00		50.00	1	
1615	1615 SOUTH GEORGETOWN PM	Distribution	Unattended	46.00	12.00		0.25	1	
1616	1616 SOUTH GEORGIA METHODIST NURSING HOME	Distribution	Unattended	46.00	0.48		3.36	6	
1617	1617 SOUTH MACON	Distribution	Unattended	115.00	12.00		25.00	1	
1618	1618 SOUTH MACON	Distribution	Unattended	115.00	12.00		22.40	1	
1619	1619 SOUTH MADISON	Distribution	Unattended	115.00	25.00		25.00	1	
1620	1620 SOUTH MADISON	Distribution	Unattended	115.00	12.00		50.00	2	
1621	1621 SOUTH MCRAE	Distribution	Unattended	46.00	12.00		10.50	2	
1622	1622 SOUTH NORCROSS	Distribution	Unattended	115.00	25.00		40.00	1	
1623	1623 SOUTH NORCROSS	Distribution	Unattended	115.00	25.00		22.40	1	
1624	1624 SOUTH NORCROSS	Distribution	Unattended	115.00	46.00		25.00	1	
1625	1625 SOUTH OGLETHORPE	Distribution	Unattended	115.00	12.00		10.50	1	
1626	1626 SOUTH OGLETHORPE	Distribution	Unattended	115.00	46.00		50.00	1	
1627	1627 SOUTH RIVER WASTEWATER TREATMENT	Distribution	Unattended	20.00	12.00		21.00	2	
1628	1628 SOUTH TIFTON	Distribution	Unattended	115.00	12.00		21.00	2	
1629	1629 SOUTH VILLA RICA	Distribution	Unattended	115.00	25.00		40.00	1	
1630	1630 SOUTH VILLA RICA	Distribution	Unattended	115.00	25.00		40.00	1	
1631	1631 SOUTHEAST TOYOTA	Distribution	Unattended	115.00	12.00		7.00	1	
1632	1632 SOUTHEAST WAYCROSS	Distribution	Unattended	115.00	12.00		22.40	1	
1633	1633 SOUTHEAST WAYCROSS	Distribution	Unattended	115.00	12.00		25.00	1	

1634	1634 SOUTHEASTERN ASSEMBLY	Distribution	Unattended	46.00	0.48		3.36	2	
1635	1635 SOUTHEASTERN REG RES LAB	Distribution	Unattended	12.00	0.48		7.00	2	
1636	1636 SOUTHERN BELL	Distribution	Unattended	13.20	0.48		3.00	2	
1637	1637 SOUTHERN GATEWAY	Distribution	Unattended	115.00	25.00		25.00	1	
1638	1638 SOUTHERN LNG	Distribution	Unattended	115.00	34.50		480.00	4	
1639	1639 SOUTHERN LNG	Distribution	Unattended	115.00	13.80		80.00	2	
1640	1640 SOUTHERN MILLS #1 (Senoia)	Distribution	Unattended	46.00	0.60		2.50	3	
1641	1641 SOUTHERN MILLS (Zebulon)	Distribution	Unattended	46.00	0.60		2.80	1	
1642	1642 SOUTHERN NATURAL GAS (Ellerslie)	Distribution	Unattended	230.00	4.00			1	
1643	1643 SOUTHERN NATURAL GAS (Ellerslie)	Distribution	Unattended	230.00	4.00		25.00	1	
1644	1644 SOUTHERN NATURAL GAS (Fairburn)	Distribution	Unattended	115.00	13.80		25.00	1	
1645	1645 SOUTHERN RAILWAY	Distribution	Unattended	12.00	2.40		2.80	3	
1646	1646 SOUTHERN RAILWAY (Inman Yards)	Distribution	Unattended	20.00	2.40		7.00	2	
1647	1647 SOUTHERN STATES CO-OP	Distribution	Unattended	46.00	0.48		1.68	1	
1648	1648 SOUTHERN WOOD SUPPLIES	Distribution	Unattended	46.00	4.00		5.25	1	
1649	1649 SOUTHERN WOOD SUPPLIES	Distribution	Unattended	46.00	0.60		7.00	1	
1650	1650 SOUTHWEST DUBLIN	Distribution	Unattended	115.00	12.00		33.60	1	
1651	1651 SOUTHWIRE	Distribution	Unattended	115.00	12.00		44.80	2	
1652	1652 SOUTHWIRE #2	Distribution	Unattended	115.00	12.00		25.00	1	
1653	1653 SPALDING	Distribution	Unattended	115.00	46.00		22.40	1	
1654	1654 SPALDING	Distribution	Unattended	115.00	12.00		7.00	1	
1655	1655 SPALDING DRIVE	Distribution	Unattended	115.00	25.00		56.00	1	
1656	1656 SPALDING DRIVE	Distribution	Unattended	115.00	20.00		56.00	1	
1657	1657 SPARTA #2	Distribution	Unattended	46.00	12.00		7.00	1	
1658	1658 SPIRIT CREEK	Distribution	Unattended	115.00	13.80		22.40	1	
1659	1659 SPIVEY LAKE	Distribution	Unattended	115.00	25.00		60.00	1	
1660	1660 SPRING STREET	Distribution	Unattended	115.00	20.00		56.00	1	
1661	1661 SPRING STREET	Distribution	Unattended	115.00	20.00		120.00	2	
1662	1662 SPRING STREET	Distribution	Unattended	115.00	20.00		50.00	1	
1663	1663 SPRINGFIELD	Distribution	Unattended	115.00	25.00		40.00	1	
1664	1664 STANDRIDGE COLOR #1	Distribution	Unattended	46.00	0.48		7.00	2	
1665	1665 STANDRIDGE COLOR #1	Distribution	Unattended	46.00	0.48		2.80	1	
1666	1666 STANDRIDGE COLOR #18 PM	Distribution	Unattended	46.00	12.00		0.75	3	

1667	1667 STANDRIDGE COLOR #2	Distribution	Unattended	46.00	0.48		3.50	1	
1668	1668 STANTON SPRINGS	Distribution	Unattended	115.00	13.80		25.00	1	
1669	1669 STATE HIGHWAY TESTING LAB	Distribution	Unattended	25.00	0.48		3.50	1	
1670	1670 STATENVILLE PD	Distribution	Unattended	46.00	12.00		5.00	1	
1671	1671 STATESBORO	Distribution	Unattended	115.00	12.00		25.00	1	
1672	1672 STATESBORO	Distribution	Unattended	115.00	12.00		22.40	1	
1673	1673 STATESBORO AREA #8 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1674	1674 STATESBORO PRIMARY	Distribution	Unattended	115.00	25.00		27.48	1	
1675	1675 STATESBORO PRIMARY	Distribution	Unattended	115.00	25.00		25.00	1	
1676	1676 STATESBORO PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1677	1677 STATHAM	Distribution	Unattended	115.00	25.00		25.00	1	
1678	1678 STEEPLECHASE PM	Distribution	Unattended	46.00	12.00		0.33	1	
1679	1679 STEVENS CREEK	Transmission	Unattended	115.00	13.80		25.00	1	
1680	1680 STILESBORO	Distribution	Unattended	46.00	12.00		10.50	2	
1681	1681 STOCKBRIDGE	Transmission	Unattended	115.00	25.00		60.00	1	
1682	1682 STOCKBRIDGE	Transmission	Unattended	230.00	115.00		300.00	1	
1683	1683 STOCKBRIDGE	Transmission	Unattended	115.00	25.00		40.00	1	
1684	1684 STOKES LAKE PD	Distribution	Unattended	46.00	25.00		5.00	1	
1685	1685 STONE MOUNTAIN	Distribution	Unattended	115.00	25.00		60.00	1	
1686	1686 STONEWALL STREET	Distribution	Unattended	115.00	12.00		50.00	2	
1687	1687 STONEY BROOK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1688	1688 STOWE WOODWARD	Distribution	Unattended	46.00	0.48		3.50	1	
1689	1689 STUBBS ROAD PM	Distribution	Unattended	46.00	7.20			1	
1690	1690 SUMMER LAKE	Distribution	Unattended	230.00	25.00		300.00	5	
1691	1691 SUMMERVILLE PRIMARY	Distribution	Unattended	115.00	12.00		9.38	1	
1692	1692 SUMMERVILLE PRIMARY	Distribution	Unattended	115.00	12.00		12.32	1	
1693	1693 SUMMERVILLE PRIMARY	Distribution	Unattended	115.00	46.00		40.00	1	
1694	1694 SUMNER	Distribution	Unattended	46.00	12.00		5.60	1	
1695	1695 SUNDANCE PRODUCTS	Distribution	Unattended	46.00	0.48		6.25	1	
1696	1696 SUNSHINE BISCUIT (Columbus)	Distribution	Unattended	12.00	0.48		2.80	1	
1697	1697 SUNSHINE BISCUIT (Columbus)	Distribution	Unattended	12.00	0.48		1.68	1	
1698	1698 SUPER SOD FARM PM	Distribution	Unattended	46.00	12.00		0.75	3	
1699	1699 SUTTONS CROSSROAD	Distribution	Unattended	46.00	12.00		5.25	1	
1700	1700 SUWANEE	Transmission	Unattended	115.00	25.00		56.00	1	

1701	1701 SUWANEE	Transmission	Unattended	115.00	25.00		60.00	1	
1702	1702 SWAINSBORO AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1703	1703 SWAINSBORO AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1704	1704 SWAINSBORO AREA #5 PM	Distribution	Unattended	46.00	12.00		0.28	1	
1705	1705 SWAINSBORO PRIMARY	Distribution	Unattended	115.00	46.00		25.00	1	
1706	1706 SWAINSBORO PRIMARY	Distribution	Unattended	115.00	12.00		50.00	2	
1707	1707 SWEET CITY PD	Distribution	Unattended	46.00	12.00		5.00	1	
1708	1708 SWEETBOTTOM	Distribution	Unattended	230.00	25.00		56.00	1	
1709	1709 SWEETBOTTOM	Distribution	Unattended	230.00	25.00		60.00	1	
1710	1710 SWEETWATER PAPER BOARD	Distribution	Unattended	46.00	0.60		21.00	3	
1711	1711 SWIFT SPINNING MILLS #2	Distribution	Unattended	115.00	25.00		25.00	1	
1712	1712 SWITCH WAY	Distribution	Unattended	230.00	12.00		60.00	1	
1713	1713 SYLVESTER PRIMARY	Transmission	Unattended	115.00	46.00		29.56	1	
1714	1714 TALLAPOOSA	Distribution	Unattended	115.00	12.00		25.00	1	
1715	1715 TALLAPOOSA	Distribution	Unattended	115.00	46.00		25.00	1	
1716	1716 TALLASSEE ROAD SCHOOL PD	Distribution	Unattended	46.00	12.00		2.50	1	
1717	1717 TALLULAH FALLS	Generation	Attended	115.00	6.60		35.84	2	
1718	1718 TALLULAH FALLS	Generation	Attended	115.00	6.60		16.00	1	
1719	1719 TALLULAH FALLS	Generation	Attended	115.00	6.60		16.00	1	
1720	1720 TALLULAH FALLS	Generation	Attended	115.00	6.60		12.00	1	
1721	1721 TALLULAH FALLS	Generation	Attended	115.00	6.60		17.92	1	
1722	1722 TALMO TAP PD	Distribution	Unattended	46.00	12.00			1	
1723	1723 TALONA PM	Distribution	Unattended	46.00	12.00		0.25	1	
1724	1724 TANNER PM	Distribution	Unattended	46.00	12.00		0.75	3	
1725	1725 TANYARD CREEK PM	Distribution	Unattended	46.00	12.00		0.25	1	
1726	1726 TARA	Distribution	Unattended	115.00	25.00		56.00	1	
1727	1727 TARVER	Transmission	Unattended	115.00	46.00		25.00	1	
1728	1728 TATUM ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1729	1729 TAZEWELL	Transmission	Unattended	230.00	46.00		40.00	1	
1730	1730 TEMPERANCE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1731	1731 TEMPLE	Distribution	Unattended	115.00	12.00		21.00	2	
1732	1732 TEMPLE INDUSTRIES (Thomson)	Distribution	Unattended	46.00	12.00		7.00	1	
1733	1733 TEMPLE INDUSTRIES (Thomson)	Distribution	Unattended	46.00	12.00		4.20	1	
1734	1734 TENNECO AUTOMOTIVE	Distribution	Unattended	115.00	12.00		22.40	1	

1735	1735 TENNILLE CITY	Distribution	Unattended	46.00	12.00		14.00	2	
1736	1736 TERRORA COMMON	Distribution	Unattended	115.00	46.00		44.80	2	
1737	1737 TERRORA COMMON	Distribution	Unattended	115.00	12.00		10.50	1	
1738	1738 TERRORA COMMON	Distribution	Unattended	115.00	6.60		30.00	1	
1739	1739 TEXAS VALLEY	Distribution	Unattended	115.00	12.00		10.50	1	
1740	1740 TEXTRON SPECIALITY PRODUCTS	Distribution	Unattended	115.00	13.80		22.40	1	
1741	1741 THALMANN	Transmission	Unattended	500.00				3	
1742	1742 THALMANN STATION SERVICE	Distribution	Unattended	115.00	12.00		9.37	2	
1743	1743 THE BRIDGE CHURCH	Distribution	Unattended	25.00	0.48		2.10	1	
1744	1744 THE ROCK	Distribution	Unattended	25.00	0.48		12.50	4	
1745	1745 THE ROCK	Distribution	Unattended	230.00	25.00		22.40	1	
1746	1746 THIELE KAOLIN (Limestone Creek)	Distribution	Unattended	46.00	12.00		7.00	1	
1747	1747 THIELE KAOLIN (Mine)	Distribution	Unattended	46.00	12.00		5.25	1	
1748	1748 THIELE KAOLIN (Sandersville)	Distribution	Unattended	46.00	12.00		14.00	2	
1749	1749 THIELE KAOLIN (Sandersville)	Distribution	Unattended	46.00	12.00		7.00	1	
1750	1750 THIELE KAOLIN (Wrens)	Distribution	Unattended	46.00	4.00		14.00	2	
1751	1751 THIELE KAOLIN (Wrens)	Distribution	Unattended	46.00	4.00		6.25	1	
1752	1752 THOMASTON	Distribution	Unattended	115.00	12.00		40.00	1	
1753	1753 THOMASTON	Distribution	Unattended	115.00	12.00		22.40	1	
1754	1754 THOMASTON	Distribution	Unattended	115.00	25.00		10.50	1	
1755	1755 THOMPSON BRIDGE	Distribution	Unattended	115.00	25.00		50.00	2	
1756	1756 THOMSON AREA #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1757	1757 THOMSON AREA #8 PD	Distribution	Unattended	46.00	25.00		5.00	1	
1758	1758 THOMSON AREA #8 PD	Distribution	Unattended	46.00	12.00		2.50	1	
1759	1759 THOMSON PRIMARY	Transmission	Unattended	13.80	0.48		1.00	1	
1760	1760 THOMSON PRIMARY	Transmission	Unattended	46.00	0.48		2.50	1	
1761	1761 THOMSON PRIMARY	Transmission	Unattended	115.00	46.00		50.00	2	
1762	1762 THRALL CAR MANUFACTURING	Distribution	Unattended	25.00	12.00		7.00	1	
1763	1763 THREE RIVERS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1764	1764 TIFTON PRIMARY	Distribution	Unattended	115.00	12.00		67.20	3	
1765	1765 TILFORD YARDS	Distribution	Unattended	115.00	25.00		180.00	3	
1766	1766 TILLY MILL	Distribution	Unattended	230.00	25.00		60.00	1	
1767	1767 TIMBERMEN #1 (Warrenton)	Distribution	Unattended	46.00	0.48		1.68	1	
1768	1768 TIMBERMEN (Camak)	Distribution	Unattended	46.00	0.48		2.80	1	

1769	1769 TIN BRIDGE PD	Distribution	Unattended	46.00	12.00		2.50	1	
1770	1770 TIOGA	Transmission	Unattended	230.00	46.00		60.00	1	
1771	1771 TNS MILLS	Distribution	Unattended	115.00	25.00		31.50	3	
1772	1772 TOCCOA	Distribution	Unattended	115.00	12.00		25.00	1	
1773	1773 TODD MARSHALL PM	Distribution	Unattended	46.00	12.00		0.25	1	
1774	1774 TODD MARSHALL PM	Distribution	Unattended	46.00	12.00		0.25	1	
1775	1775 TOLLESON LUMBER (Perry)	Distribution	Unattended	46.00	0.48		5.60	3	
1776	1776 TOM HUSTON PEANUT (Bakery)	Distribution	Unattended	12.00	0.48		3.50	1	
1777	1777 TOMMY FIELDS PM	Distribution	Unattended	46.00	12.00		0.28	1	
1778	1778 TOTAL SYSTEM SERVICES	Distribution	Unattended	115.00	25.00		10.50	1	
1779	1779 TOTO	Distribution	Unattended	25.00	4.00		7.00	1	
1780	1780 TOWNSEND	Distribution	Unattended	115.00	12.00		5.25	1	
1781	1781 TOYO	Distribution	Unattended	115.00	12.00		80.00	2	
1782	1782 TRANQUILLA HILL	Distribution	Unattended	115.00	25.00		40.00	1	
1783	1783 TRANSCO	Distribution	Unattended	115.00	12.00		25.00	1	
1784	1784 TRANSCO	Distribution	Unattended	115.00	25.00		60.00	1	
1785	1785 TRENCH SHORING SERVICES	Distribution	Unattended	46.00	0.48		2.80	1	
1786	1786 TRENT TUBE	Distribution	Unattended	46.00	0.48		3.50	1	
1787	1787 TRENTON	Distribution	Unattended	46.00	12.00		7.00	1	
1788	1788 TRENTON	Distribution	Unattended	46.00	25.00		21.00	3	
1789	1789 TRENTON	Distribution	Unattended	46.00	12.00		6.25	1	
1790	1790 TRENTON	Distribution	Unattended	46.00	12.00		5.00	1	
1791	1791 TREUTLEN	Distribution	Unattended	115.00	25.00		100.00	2	
1792	1792 TRI COUNTY FARMS PM	Distribution	Unattended	46.00	12.00		0.75	3	
1793	1793 TRIBUTARY	Transmission	Unattended	230.00	20.00		60.00	1	
1794	1794 TRINITY INDUSTRIES	Distribution	Unattended	46.00	0.48		2.50	3	
1795	1795 TRION	Distribution	Unattended	115.00	12.00		50.00	2	
1796	1796 TRIPPS BEACH PM	Distribution	Unattended	46.00	12.00		0.28	1	
1797	1797 TRONOX	Distribution	Unattended	115.00	13.80		33.60	1	
1798	1798 TROUP CREEK	Distribution	Unattended	115.00	12.00		25.00	1	
1799	1799 TROUP CREEK	Distribution	Unattended	115.00	12.00		67.20	2	
1800	1800 TROY ALDRIDGE PM	Distribution	Unattended	46.00	0.48		0.15	1	
1801	1801 TRUMAN PARKWAY	Distribution	Unattended	115.00	13.80		33.60	1	
1802	1802 TRUMAN PARKWAY	Distribution	Unattended	115.00	13.80		33.60	1	
1803	1803 TUCKER	Distribution	Unattended	115.00	12.00		40.00	1	

1804	1804 TUCKER	Distribution	Unattended	115.00	12.00		25.00	1	
1805	1805 TUGALO	Generation	Attended	115.00	6.60		80.00	2	
1806	1806 TURPIN HILL	Distribution	Unattended	115.00	13.80		50.00	2	
1807	1807 TWILIGHT	Distribution	Unattended	115.00	25.00		60.00	1	
1808	1808 TWIN CITY	Distribution	Unattended	115.00	12.00		10.50	1	
1809	1809 TWIN LAKES	Transmission	Unattended	115.00	69.00	13	60.00	1	
1810	1810 TWIN LAKES	Transmission	Unattended	115.00	69.00		60.00	1	
1811	1811 TWIN PINES	Distribution	Unattended	115.00	12.00		44.80	2	
1812	1812 TY TY PD	Distribution	Unattended	46.00	12.00		5.00	1	
1813	1813 TYBEE ISLAND	Distribution	Unattended	46.00	13.80		25.00	1	
1814	1814 TYBEE ISLAND	Distribution	Unattended	46.00	13.80		25.00	1	
1815	1815 TYCO PLASTICS #1	Distribution	Unattended	46.00	0.48		2.80	1	
1816	1816 TYCO PLASTICS #11 PD	Distribution	Unattended	46.00			2.50	1	
1817	1817 TYCO PLASTICS #12 PD	Distribution	Unattended	46.00			2.50	1	
1818	1818 TYCO PLASTICS #4	Distribution	Unattended	46.00	0.48		3.50	1	
1819	1819 TYCO PLASTICS #8	Distribution	Unattended	46.00	0.48		7.00	2	
1820	1820 TYSON FOODS (Cumming)	Distribution	Unattended	12.00	0.48		6.25	1	
1821	1821 TYSON FOODS (Cumming)	Distribution	Unattended	12.00	0.48		3.50	1	
1822	1822 U.S. CAN (Tallapoosa)	Distribution	Unattended	46.00	0.48		3.50	1	
1823	1823 U.S. MARINE CORPS (MOCK ROAD)	Distribution	Unattended	115.00	34.50		40.00	1	
1824	1824 U.S. MARINE CORPS SUPPLY DEPOT	Distribution	Unattended	34.50	12.00		25.00	1	
1825	1825 U.S. MARINE CORPS SUPPLY DEPOT	Distribution	Unattended	115.00	12.00		22.40	1	
1826	1826 U.S. POSTAL FACILITY (Hapeville)	Distribution	Unattended	20.00	4.00		5.00	1	
1827	1827 U.S. POSTAL SERVICE	Distribution	Unattended	115.00	12.00		14.00	2	
1828	1828 U.S. VETERANS HOSPITAL (Dublin)	Distribution	Unattended	12.00	4.00		5.00	1	
1829	1829 U.S. VETERANS HOSPITAL (Dublin)	Distribution	Unattended	46.00	4.00		14.00	2	
1830	1830 UNILEVER	Distribution	Unattended	20.00	4.00		4.69	1	
1831	1831 UNIMIN	Distribution	Unattended	46.00	12.00		5.25	1	
1832	1832 UNION POINT AREA #1 PM (RETIRED)	Distribution	Unattended	46.00	12.00		0.25	1	
1833	1833 UNION POINT PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1834	1834 UNION POINT PRIMARY	Transmission	Unattended	115.00	25.00		10.50	1	
1835	1835 UNITED PARCEL SERVICE	Distribution	Unattended	115.00	20.00		50.00	2	
1836	1836 UNIVERSITY CENTER	Distribution	Unattended	115.00	20.00		60.00	1	
1837	1837 UNIVERSITY OF GEORGIA	Distribution	Unattended	115.00	12.00		80.00	2	

1838	1838 UNIVERSITY OF GEORGIA	Distribution	Unattended	115.00	12.00		25.00	1	
1839	1839 UNIVETER CROSSING	Distribution	Unattended	115.00	25.00		40.00	1	
1840	1840 UPS DATA CENTER (Alpharetta)	Distribution	Unattended	25.00	12.00		44.80	2	
1841	1841 US 1 RECYCLING	Distribution	Unattended	46.00	4.00		4.69	1	
1842	1842 UVALDA	Distribution	Unattended	46.00	12.00		5.25	1	
1843	1843 VALDOSTA	Distribution	Unattended	115.00	12.00		40.00	1	
1844	1844 VALLEY HILL ROAD	Distribution	Unattended	115.00	25.00		60.00	1	
1845	1845 VARNELL	Distribution	Unattended	115.00	12.00		7.00	1	
1846	1846 VARNELL	Distribution	Unattended	115.00	12.00		6.25	1	
1847	1847 VENUS THREAD	Distribution	Unattended	46.00	0.60		5.75	3	
1848	1848 VERDERY STREET	Distribution	Unattended	115.00	13.80		33.60	1	
1849	1849 VICTORY DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
1850	1850 VICTORY DRIVE	Distribution	Unattended	115.00	12.00		25.00	1	
1851	1851 VIDALIA	Distribution	Unattended	115.00	46.00		56.00	1	
1852	1852 VIDALIA	Distribution	Unattended	115.00	12.00		44.80	2	
1853	1853 VIENNA PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
1854	1854 VIENNA PRIMARY	Transmission	Unattended	115.00	46.00		50.00	1	
1855	1855 VIENNA PRIMARY	Transmission	Unattended	115.00	12.00		25.00	1	
1856	1856 VILLA RICA PRIMARY	Transmission	Unattended	46.00	0.48		2.50	1	
1857	1857 VINEVILLE	Distribution	Unattended	115.00	12.00		67.20	3	
1858	1858 VINSON ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
1859	1859 VIRGINIA AVENUE	Distribution	Unattended	230.00	20.00		120.00	2	
1860	1860 VISY PAPER	Distribution	Unattended	115.00	13.80		25.00	1	
1861	1861 VOGTLE 1&2	Generation	Attended	500.00	25.00		1356.00	3	
1862	1862 VOGTLE 1&2	Generation	Attended	500.00				3	
1863	1863 VOGTLE 1&2	Generation	Attended	500.00				3	
1864	1864 VOGTLE 1&2	Generation	Attended	25.00	1.00		17.14	2	
1865	1865 VOGTLE 1&2	Generation	Attended	230.00	13.80		134.40	2	
1866	1866 VOGTLE 1&2	Generation	Attended	230.00	13.80		134.40	2	
1867	1867 VOGTLE 1&2	Generation	Attended	25.00	13.80		336.00	6	
1868	1868 VOGTLE 1&2	Generation	Attended	13.80	4.00		12.50	1	
1869	1869 VOGTLE 1&2	Generation	Attended	13.80	4.00		12.50	1	
1870	1870 VOGTLE 1&2	Generation	Attended	500.00	25.00		1356.00	3	
1871	1871 VOGTLE 1&2	Generation	Attended	25.00	1.00		17.14	2	
1872	1872 VOGTLE 1&2	Generation	Attended	25.00	13.80		336.00	6	

1873	1873 VOGTLE 1&2	Generation	Attended	230.00	25.00		1864.00	4	
1874	1874 VOGTLE 1&2	Generation	Attended	230.00	25.00		1864.00	4	
1875	1875 VOGTLE 230KV SWITCHING	Transmission	Unattended	230.00	13.80		25.00	1	
1876	1876 VOGTLE 3&4 500KV	Generation	Attended	500.00				3	
1877	1877 VOGTLE 3&4 500KV	Generation	Attended	6.60	0.48		1.00	1	
1878	1878 VOGTLE 3&4 500KV	Generation	Attended	230.00	25.00		1840.00	4	
1879	1879 VOGTLE 3&4 500KV	Generation	Attended	500.00	25.00		1840.00	4	
1880	1880 VOGTLE 3&4 500KV	Generation	Attended	25.00	1.00		20.00	2	
1881	1881 VULCAN MATERIALS (Columbus)	Distribution	Unattended	25.00	2.40		4.20	1	
1882	1882 VULCAN MATERIALS (Grayson)	Distribution	Unattended	115.00	12.00		14.00	2	
1883	1883 VULCAN MATERIALS (Lithia Springs)	Distribution	Unattended	46.00	2.40		14.00	2	
1884	1884 VULCAN MATERIALS (Lithonia)	Distribution	Unattended	46.00	12.00		5.25	1	
1885	1885 VULCAN MATERIALS (Madras)	Distribution	Unattended	46.00	12.00		5.25	1	
1886	1886 W. G. JOHNSON PM	Distribution	Unattended	46.00	12.00		0.25	1	
1887	1887 W. L. BONNELL #1	Distribution	Unattended	46.00	0.48		5.60	2	
1888	1888 W. L. BONNELL #2	Distribution	Unattended	46.00	0.48		7.00	2	
1889	1889 W. L. BONNELL #3	Distribution	Unattended	46.00	0.48		1.12	3	
1890	1890 W. M. WRIGLEY	Distribution	Unattended	115.00	4.00		42.00	4	
1891	1891 W. S. CATRETT PM	Distribution	Unattended	46.00	12.00		0.25	1	
1892	1892 WABASH	Distribution	Unattended	230.00	20.00		112.00	2	
1893	1893 WABASH	Distribution	Unattended	230.00	20.00		60.00	1	
1894	1894 WACO	Distribution	Unattended	46.00	12.00		7.00	1	
1895	1895 WALKER CO. INDUSTRIAL PARK	Distribution	Unattended	115.00	25.00		25.00	1	
1896	1896 WALLACE DAM	Generation	Attended	14.40	0.48			1	
1897	1897 WALLACE DAM	Generation	Attended	14.40	0.48		5.04	3	
1898	1898 WALLACE DAM	Generation	Attended	230.00	13.80		390.00	2	
1899	1899 WALMART	Distribution	Unattended	115.00	25.00		10.50	1	
1900	1900 WALTHOURVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
1901	1901 WALTHOURVILLE	Distribution	Unattended	115.00	12.00		25.00	1	
1902	1902 WANSLEY	Generation	Attended	4.00	0.48		1.12	2	
1903	1903 WANSLEY	Generation	Attended	13.80	4.00		21.00	2	
1904	1904 WANSLEY FGD	Generation	Attended	230.00	13.80		120.00	2	
1905	1905 WANSLEY PUMPING	Distribution	Unattended	115.00	12.00		7.00	1	
1906	1906 WANSLEY PUMPING	Distribution	Unattended	115.00	4.00		11.20	2	

1907	1907 WARM SPRINGS ROAD	Distribution	Unattended	115.00	25.00		50.00	1	
1908	1908 WARRENTON	Distribution	Unattended	46.00	8.00		28.00	4	
1909	1909 WARRENTON AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1910	1910 WARRENTON AREA #3 PM	Distribution	Unattended	46.00	12.00		0.50	2	
1911	1911 WARRENTON PRIMARY	Transmission	Unattended	115.00	46.00		22.40	1	
1912	1912 WARRENTON PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1913	1913 WASHINGTON	Distribution	Unattended	115.00	12.00		41.70	1	
1914	1914 WATKINS WOODS PM	Distribution	Unattended	46.00	12.00		0.25	1	
1915	1915 WAVERLY PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1916	1916 WAVERLY PRIMARY	Transmission	Unattended	115.00	12.00		10.50	1	
1917	1917 WAX	Distribution	Unattended	46.00	12.00		7.00	1	
1918	1918 WAX	Distribution	Unattended	46.00	12.00		5.25	1	
1919	1919 WAYCROSS	Distribution	Unattended	115.00	12.00		21.00	2	
1920	1920 WAYCROSS MOULDED PRODUCTS	Distribution	Unattended	12.00	0.48		2.80	1	
1921	1921 WAYNE FARMS	Distribution	Unattended	46.00	0.48		7.00	1	
1922	1922 WAYNESBORO	Distribution	Unattended	115.00	12.00		25.00	1	
1923	1923 WAYNESBORO PRIMARY	Transmission	Unattended	115.00	46.00		25.00	1	
1924	1924 WELCOME ALL ROAD	Distribution	Unattended	230.00	25.00		120.00	2	
1925	1925 WELLS ALUMINUM #2 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1926	1926 WELLS ALUMINUM #2 PM	Distribution	Unattended	46.00	12.00		0.50	2	
1927	1927 WESLEYAN DRIVE	Distribution	Unattended	115.00	4.00		7.00	1	
1928	1928 WESLEYAN DRIVE	Distribution	Unattended	115.00	12.00		33.60	1	
1929	1929 WEST 11TH STREET	Distribution	Unattended	115.00	12.00		21.00	2	
1930	1930 WEST ATHENS	Distribution	Unattended	115.00	12.00		44.80	2	
1931	1931 WEST AUGUSTA	Distribution	Unattended	115.00	13.80		50.00	2	
1932	1932 WEST CRAWFORDVILLE	Distribution	Unattended	46.00	25.00		7.00	1	
1933	1933 WEST DALLAS	Distribution	Unattended	115.00	12.00		25.00	1	
1934	1934 WEST DALLAS	Distribution	Unattended	115.00	46.00		22.40	1	
1935	1935 WEST DALLAS	Distribution	Unattended	115.00	25.00		10.50	1	
1936	1936 WEST DICKEY PM	Distribution	Unattended	46.00	12.00		0.25	1	
1937	1937 WEST DICKEY PM	Distribution	Unattended	46.00	12.00		0.50	2	
1938	1938 WEST DUBLIN	Distribution	Unattended	230.00	12.00		67.20	2	
1939	1939 WEST END	Distribution	Unattended	115.00	20.00		100.00	2	
1940	1940 WEST GRIFFIN	Distribution	Unattended	46.00	12.00		14.00	2	
1941	1941 WEST MABLETON	Distribution	Unattended	115.00	12.00		40.00	1	

1942	1942 WEST MOULTRIE	Distribution	Unattended	46.00	12.00		5.25	1	
1943	1943 WEST POINT FOUNDRY & MACHINE	Distribution	Unattended	12.00	0.60		2.80	3	
1944	1944 WEYERHAEUSER (Colbert)	Distribution	Unattended	115.00	25.00		10.50	1	
1945	1945 WEYERHAEUSER (Savannah)	Distribution	Unattended	46.00	13.80		33.60	1	
1946	1946 WHEELER ROAD	Distribution	Unattended	230.00	12.00		33.60	1	
1947	1947 WHIRLWIND STEEL PD	Distribution	Unattended	46.00	0.48		2.50	1	
1948	1948 WHITE PM	Distribution	Unattended	46.00	12.00		0.25	1	
1949	1949 WHITE BLUFF	Transmission	Unattended	115.00	13.80		50.00	2	
1950	1950 WHITEHALL	Distribution	Unattended	115.00	12.00		25.00	1	
1951	1951 WHITEMARSH ISLAND	Distribution	Unattended	115.00	13.80		25.00	1	
1952	1952 WHITEMARSH ISLAND	Distribution	Unattended	115.00	13.80		14.00	1	
1953	1953 WHITEOAK	Transmission	Unattended	115.00	12.00		67.20	3	
1954	1954 WHITEOAK	Transmission	Unattended	115.00	46.00		50.00	1	
1955	1955 WHITESBURG	Distribution	Unattended	46.00	12.00		5.25	1	
1956	1956 WHITESTONE PD	Distribution	Unattended	46.00	12.00		2.50	1	
1957	1957 WHITESTONE PD	Distribution	Unattended	46.00	12.00		0.25	1	
1958	1958 WHITEWATER	Distribution	Unattended	46.00	12.00		5.25	1	
1959	1959 WIDOW HILL PM	Distribution	Unattended	46.00	12.00		0.25	1	
1960	1960 WIEUCA ROAD	Distribution	Unattended	230.00	20.00		60.00	1	
1961	1961 WILDER ROAD PM	Distribution	Unattended	46.00	12.00		0.25	1	
1962	1962 WILLACOOCHEE CITY	Distribution	Unattended	46.00	12.00		7.00	1	
1963	1963 WILLIAMS CIRCLE SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
1964	1964 WILLINGHAM DRIVE	Distribution	Unattended	115.00	20.00		56.00	1	
1965	1965 WILLINGHAM DRIVE	Distribution	Unattended	115.00	20.00		60.00	1	
1966	1966 WILLINGHAM DRIVE	Distribution	Unattended	115.00	20.00		50.00	1	
1967	1967 WILLOW RUN ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
1968	1968 WILLOW RUN ROAD	Distribution	Unattended	115.00	25.00		25.00	1	
1969	1969 WILMINGTON ISLAND	Transmission	Unattended	115.00	13.80		80.00	2	
1970	1970 WILMINGTON ISLAND	Transmission	Unattended	115.00	46.00		50.00	2	
1971	1971 WILSON	Generation	Attended	13.80	0.48		2.52	3	
1972	1972 WILSON	Generation	Attended	230.00	13.80		145.00	1	
1973	1973 WILSON	Generation	Attended	13.80	13.80		44.80	2	
1974	1974 WILSON	Generation	Attended	4.00	0.48		0.84	1	
1975	1975 WILSON	Generation	Attended	230.00	13.80		25.00	1	
1976	1976 WILSON	Generation	Attended	13.80	0.48		1.68	1	

1977	1977 WILSON	Generation	Attended	230.00	13.20		244.00	2	
1978	1978 WILSON	Generation	Attended	4.00	2.40		2.25	1	
1979	1979 WINCHESTER SUBDIVISION PM	Distribution	Unattended	46.00	12.00		0.25	1	
1980	1980 WIND GAP FARMS	Distribution	Unattended	46.00	12.00		2.50	3	
1981	1981 WINDER PRIMARY	Distribution	Unattended	115.00	25.00		40.00	1	
1982	1982 WINDER PRIMARY	Distribution	Unattended	115.00	12.00		22.40	1	
1983	1983 WINDWARD	Distribution	Unattended	230.00	25.00		240.00	4	
1984	1984 WINDY HILL	Distribution	Unattended	115.00	20.00		112.00	2	
1985	1985 WINDY HILL	Distribution	Unattended	20.00	12.00		22.40	1	
1986	1986 WINN DIXIE PM (Powder Springs)	Distribution	Unattended	46.00	12.00		0.75	3	
1987	1987 WINN DIXIE (Atlanta)	Distribution	Unattended	20.00	12.00		12.50	2	
1988	1988 WINTERTHUR	Distribution	Unattended	115.00	20.00		56.00	1	
1989	1989 WINTERVILLE	Distribution	Unattended	46.00	12.00		5.25	1	
1990	1990 WOODBINE	Distribution	Unattended	115.00	12.00		14.00	2	
1991	1991 WOODBURY	Distribution	Unattended	46.00	12.00		7.00	1	
1992	1992 WOODGRAIN MILLWORK	Distribution	Unattended	46.00	4.00		4.69	1	
1993	1993 WOODPECKER PM	Distribution	Unattended	46.00	12.00		0.25	1	
1994	1994 WOODVALLEY	Distribution	Unattended	115.00	12.00		33.60	1	
1995	1995 WRENS	Distribution	Unattended	46.00	12.00		5.25	1	
1996	1996 WRENS	Distribution	Unattended	46.00	12.00		5.25	1	
1997	1997 WRENS	Distribution	Unattended	46.00	12.00		4.20	1	
1998	1998 WRENS AREA #1 PM	Distribution	Unattended	46.00	12.00		0.25	1	
1999	1999 WRENS PRIMARY	Distribution	Unattended	46.00	25.00		8.13	1	
2000	2000 WRENS PRIMARY	Distribution	Unattended	230.00	46.00		60.00	1	
2001	2001 WRIGHTSBORO ROAD	Distribution	Unattended	115.00	12.00		40.00	1	
2002	2002 WRIGHTSVILLE	Distribution	Unattended	46.00	12.00		8.40	2	
2003	2003 WRIGHTSVILLE PRIMARY	Transmission	Unattended	230.00	46.00		33.60	1	
2004	2004 WYNNTON	Distribution	Unattended	115.00	12.00		40.00	1	
2005	2005 YAMAHA	Distribution	Unattended	115.00	25.00		60.00	1	
2006	2006 YAMAHA	Distribution	Unattended	115.00	25.00		10.50	1	
2007	2007 YATES 6&7	Generation	Attended	230.00	23.00		440.00	1	
2008	2008 YATES 6&7	Generation	Attended	230.00			440.00	1	
2009	2009 YATES 6&7	Generation	Attended	20.00	4.00		28.00	2	
2010	2010 YATES 6&7	Generation	Attended	20.00	4.00		20.00	2	
2011	2011 YATES COMMON	Transmission	Unattended	115.00	46.00		50.00	1	

2012	2012 YATES VILLAGE PD	Distribution	Unattended	46.00	12.00		5.00	1	
2013	2013 YONAH	Generation	Attended	115.00	6.60		30.00	3	
2014	2014 YONAH	Generation	Attended	115.00	12.00		10.50	1	
2015	2015 YOSHIDA	Distribution	Unattended	115.00	12.00		33.60	1	
2016	2016 YOUNG STATION	Distribution	Unattended	46.00	12.00		21.00	2	
2017	2017 ZEBULON ROAD	Distribution	Unattended	115.00	12.00		25.00	1	
2018	2018 ZIPPER	Distribution	Unattended	115.00	12.00		25.00	1	
1	TotalDistributionSubstationMember						44,445		
2	TotalGenerationSubstationMember						34,741		
3	TotalTransmissionSubstationMember						7,105		
4	Total						86,291		

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ 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	Accounting, Finance, Treasury	[a] Southern Company Services	[c] See Notes	44,756,487
3	Administrative and General Services	Southern Company Services	[d] See Notes	142,130,036
4	Information Technology	Southern Company Services	[e] See Notes	585,303,853
5	Power Delivery Support Services	Southern Company Services	[f] See Notes	424,815,368
6	Nuclear Administrative and Other Related Services	[b] Southern Nuclear Operating Company	182.3,232,426.1,426.4,426.5,920,921	88,675,927
7	Nuclear Engineering Construction and Removal Serv.	Southern Nuclear Operating Company	107,108,120.1,184	155,571,227
8	Nuclear Engineering Maintenance Services	Southern Nuclear Operating Company	528,529,530,531,532	108,463,156
9	Nuclear Engineering Operating Services	Southern Nuclear Operating Company	154,186,517,518,519,520,523,524,525	477,908,041
10	Distribution Servics	Southern Nuclear Operating Company	580,590	677
11	Other Power Generation	Southern Nuclear Operating Company	506,546,547,548,549,552,553,554	1,299,863
12	Preliminary Survey and Investigation Services	Southern Nuclear Operating Company	183	3,445,678
13	Storm Assistance	Alabama Power Company	182.3,426.5,573,593	28,401,267
14	Supply Chain Management	Alabama Power Company	923	394,919
15	Material Sale	Alabama Power Company	154	6,714,937
16	Supplemental Executive Retirement Plan (SERP)	Alabama Power Company	234	[g] 251,570
17	Storm Assistance	Mississippi Power Company	182.3,593	6,070,600
18	PPE Testing	Mississippi Power Company	511,523,524,542,552,568,588	625,705
19	Supplemental Executive Retirement Plan (SERP)	Southern Communications Services, Inc.	234	1,155,848
20	Supplemental Executive Retirement Plan (SERP)	Atlanta Gas & Light	234	498,258
19				

20	**Non-power Goods or Services Provided for Affiliated**			
21	Administrative & Other Related Services	Southern Company Services	146	23,513,535
22	Material Services	Southern Company Services	146	474,174
23	Occupancy	Southern Company Services	146	7,520,685
24	Printing Service	Southern Company Services	146	132,946
25	Supply Chain Management	Southern Company Services	146	5,349,927
26	Vehicle Fleet Services	Southern Company Services	146	386,993
27	Material Sale	Alabama Power Company	146	4,314,922
28	Storm Assistance	Alabama Power Company	146	663,310
29	Material Sale	Mississippi Power Company	146	737,184
30	Storm Assistance	Mississippi Power Company	146	386,423
31	Supplemental Executive Retirement Plan (SERP)	Southern Communications Services, Inc.	146	3,221,424
32	Supplemental Executive Retirement Plan (SERP)	Atlanta Gas & Light	146	5,900,383
42				

Name of Respondent: Georgia Power Company	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 04/03/2025	Year/Period of Report End of: 2024/ Q4

FOOTNOTE DATA

(a) Concept: NameOfAssociatedAffiliatedCompany

Southern Company Services
Southern Company Services, Inc. uses multiple allocation methodologies to allocate costs. These methodologies are designed to properly allocate cost on a causative basis and to prevent cross-subsidization among affiliated and non-affiliated companies. See Southern Company Services FERC Form 60 Schedule XXI for additional information. This note applies to Line Nos. 2, 3, 4, and 5 on page 429.

(b) Concept: NameOfAssociatedAffiliatedCompany

Southern Nuclear Operating Company
Georgia Power Company (GPC) is billed direct and allocated costs by Southern Nuclear Operating Company Inc. (SNC). For the period of January through April 2024, SNC allocated costs to GPC using the Unit Basis Method. The Unit Basis Method of allocation is the factor determined by dividing GPC operating units by the total number of units. GPC received 5/7 of SNC allocated costs since GPC owned five and APC owned two of the seven units operated by SNC during this period. Effective May 2024, SNC allocated costs to GPC using the Plant Basis Method. The Plant Basis Method of allocation is the factor determined by dividing GPC operating plants by total number of plants. GPC received 3/4 of SNC allocated costs since GPC owned three and Alabama Power Company (APC) owned one of the four plants operated by SNC during this period. This note applies to Line Nos. 6, 7, 8, 9, 10, 11, and 12 on page 429.

(c) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Accounting, Finance & Treasury
107,232,408.2,416,426.5,501,506,547,549,560,561,562,568,903,921,923,928,930.2.

(d) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Administrative and General Services
107,108,154,163,165,181,182.3,183,184,186,232,241,408.2,415,416,417,426.1,426.3,426.4,426.5,431,442,506,
517,524,528,529,531,532,539,549,555,562,566,568,573,588,590,593,596,901,902,903,905,908,910,911,912,
913,916,920,921,923,924,925,926,928,930.2,935.

(e) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Information Technology
107,108,182.3,184,232,416,417,426.5,506,524,539,549,553,566,584,586,588,590,597,902,903,905,908,912,921,923.

(f) Concept: AccountsChargedOrCreditedTransactionsWithAssociatedAffiliatedCompanies

Power Delivery Support Services
107,108,120.1,165,174,182.3,183,184,186,232,253,404,408.2,415,416,417,426.5,431,456,500,501,502,505,506,
510,511,512,513,514,517,519,520,524,528,529,530,531,532,535,538,539,541,542,543,544,545,546,547,548,
549,551,552,553,554,555,556,557,560,561,562,563,566,568,569,570,571,573,580,581,582,583,584,586,587,
588,590,591,592,593,594,595,596,902,908,912,921,923,926,928,930.2,935.

(g) Concept: DueToOrChargedByTheTransactionsWithAssociatedAffiliatedCompanies

Mississippi Power Company is reporting $626,167 for PPE Testing and GPC is reporting $625,705. The difference is due to the timing of invoicing and payments.

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