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

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2024

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 333-192954

OglethorpePowerCorporation

(An Electric Membership Corporation)

(Exact name of registrant as specified in its charter)

Georgia (State or other jurisdiction of incorporation or organization)	58-1211925 (I.R.S. employer identification no.)
2100 East Exchange Place Tucker, Georgia (Address of principal executive offices)	30084-5336 (Zip Code)
Registrant's telephone number, including area code	**(770) 270-7600**

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). **Yes** ☒ **No** ☐

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

Large Accelerated Filer ☐ **Accelerated Filer** ☐ **Non-Accelerated Filer** ☒ **Smaller Reporting Company** ☐ **Emerging Growth Company** ☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ☐ **No** ☒

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

Title of each class:	Trading Symbol(s)	Name of each exchange on which registered:
None	N/A	N/A

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. **The registrant is a membership corporation and has no authorized or outstanding equity securities.**

OGLETHORPE POWER CORPORATION

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FOR THE QUARTER ENDED JUNE 30, 2024

CAUTIONARY STATEMENT REGARDING

FORWARD-LOOKING INFORMATION

This quarterly report on Form 10-Q contains "forward-looking statements." All statements, other than statements of historical facts, that address activities, events or developments that we expect or anticipate to occur in the future, including matters such as future capital expenditures, business strategy, regulatory actions, and development, construction or operation of facilities (often, but not always, identified through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "projection," "target" and "outlook") are forward-looking statements.

Although we believe that in making these forward-looking statements our expectations are based on reasonable assumptions, any forward-looking statement involves uncertainties and there are important factors that could cause actual results to differ materially from those expressed or implied by these forward-looking statements. Some of the risks, uncertainties and assumptions that may cause actual results to differ from these forward-looking statements are described under "Item 1A—RISK FACTORS" and in other sections of our annual report on Form 10-K for the fiscal year ended December 31, 2023, and under "Risk Factors" and in other sections of our quarterly report on Form 10-Q for the quarterly period ended March 31, 2024 and in this quarterly report on Form 10-Q. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this quarterly report may not occur.

Any forward-looking statement speaks only as of the date of this quarterly report, and, except as required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of them; nor can we assess the impact of each factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- cost increases and schedule delays with respect to our capital improvement and construction projects, such as our two new natural gas-fired generation facilities, the closure of coal ash ponds and any other future generation projects we may undertake;
- the impact of regulatory or legislative responses to climate change initiatives or efforts to reduce greenhouse gas emissions, including carbon dioxide;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- our access to capital, the cost to access capital, and the results of our financing and refinancing efforts, including availability of funds in the capital markets;
- the continued availability of funding from the Rural Utilities Service;
- increasing debt caused by significant capital expenditures;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- actions by credit rating agencies;
- commercial banking and financial market conditions;
- the impact of load growth in our members' service territories and any decisions regarding the development of additional generation resources to meet the additional demand;
- our participation in any federal loan or grant programs for which we qualify and are selected and our ability to meet the applicable loan or grant conditions and requirements;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;

- adequate funding of our nuclear and coal ash pond decommissioning funds, including investment performance and projected decommissioning costs;
- continued efficient operation of our generation facilities by us and third-parties;
- the availability of an adequate and economical supply of fuel, water and other materials;
- reliance on third-parties to efficiently manage, distribute and deliver generated electricity;
- the direct or indirect effect on our business resulting from cyber or physical attacks on us, our members or third-party service providers, vendors or contractors;
- changes in technology available to and utilized by us, our competitors, or residential or commercial consumers in our members' service territories, including from the development and deployment of distributed generation and energy storage technologies;
- the inability of counterparties to meet their obligations to us, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- our members' ability to offer their residential, commercial and industrial customers competitive rates;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption, energy conservation and efficiency efforts and the general economy;
- general economic conditions;
- weather conditions and other natural phenomena;
- litigation or legal and administrative proceedings and settlements;
- unanticipated changes in interest rates or rates of inflation;
- early retirement of our co-owned coal units;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- acts of sabotage, wars or terrorist activities, including cyber attacks;
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards;
- catastrophic events such as fires, earthquakes, floods, droughts, hurricanes, explosions, pandemic health events, or similar occurrences;
- significant changes in critical accounting policies material to us; and
- other factors discussed elsewhere in this quarterly report and in other reports we file with the SEC.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
June 30, 2024 and December 31, 2023

	(dollars in thousands)	
	2024	2023
Assets		
Electric plant:		
In service	**$ 17,522,416**	$ 14,112,098
Right-of-use assets—finance leases	**302,732**	302,732
Less: Accumulated provision for depreciation	**(5,564,073)**	(5,418,738)
Electric plant in service, net	**12,261,075**	8,996,092
Nuclear fuel, at amortized cost	**384,871**	389,662
Construction work in progress	**255,681**	3,294,641
Total electric plant	**12,901,627**	12,680,395
Investments and funds:		
Nuclear decommissioning trust fund	**686,619**	641,239
Investment in associated companies	**83,831**	82,133
Long-term investments	**630,385**	690,732
Other	**36,591**	35,585
Total investments and funds	**1,437,426**	1,449,689
Current assets:		
Cash and cash equivalents	**313,824**	490,592
Short-term investments	**147,156**	143,931
Receivables	**252,059**	201,784
Inventories, at weighted average cost	**309,995**	337,045
Prepayments and other current assets	**34,216**	18,335
Total current assets	**1,057,250**	1,191,687
Deferred charges and other assets:		
Regulatory assets	**1,138,527**	1,131,489
Prepayments to Georgia Power Company	**16,686**	13,722
Other	**52,315**	57,869
Total deferred charges	**1,207,528**	1,203,080
Total assets	**$ 16,603,831**	$ 16,524,851

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

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
June 30, 2024 and December 31, 2023

	(dollars in thousands)	
	2024	2023
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 1,324,207**	$ 1,257,917
Long-term debt	**11,756,561**	11,600,917
Obligation under finance leases	**38,520**	43,586
Obligation under Rocky Mountain transactions	**30,869**	29,862
Other	**6,588**	5,152
Total capitalization	**13,156,745**	12,937,434
Current liabilities:		
Long-term debt and finance leases due within one year	**386,954**	384,426
Short-term borrowings	**473,300**	607,885
Accounts payable	**80,856**	117,272
Accrued interest	**102,684**	106,355
Member power bill prepayments, current	**19,664**	31,406
Other current liabilities	**91,688**	111,109
Total current liabilities	**1,155,146**	1,358,453
Deferred credits and other liabilities:		
Asset retirement obligations	**1,551,526**	1,458,937
Member power bill prepayments, non-current	**68,683**	47,133
Regulatory liabilities	**652,043**	706,320
Other	**19,688**	16,574
Total deferred credits and other liabilities	**2,291,940**	2,228,964
Total equity and liabilities	**$ 16,603,831**	$ 16,524,851

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

Oglethorpe Power Corporation
Consolidated Statements of Revenues and Expenses (Unaudited)
For the Three and Six Months Ended June 30, 2024 and 2023

	(dollars in thousands)			
	Three Months		Six Months	
	2024	2023	**2024**	2023
Operating revenues:				
Sales to members	**$ 562,267**	$ 365,496	**$ 1,097,637**	$ 753,149
Sales to non-members	**1,823**	23,893	**2,767**	25,693
Total operating revenues	**564,090**	389,389	**1,100,404**	778,842
Operating expenses:				
Fuel	**148,463**	132,468	**315,509**	265,636
Production	**148,919**	99,412	**267,009**	192,879
Depreciation and amortization	**103,949**	73,015	**198,054**	145,689
Purchased power	**19,202**	17,785	**38,422**	35,415
Accretion	**18,417**	16,722	**36,039**	32,230
Total operating expenses	**438,950**	339,402	**855,033**	671,849
Operating margin	**125,140**	49,987	**245,371**	106,993
Other income:				
Investment income	**15,900**	17,943	**32,952**	34,325
Other	**2,943**	2,909	**5,747**	5,834
Total other income	**18,843**	20,852	**38,699**	40,159
Interest charges:				
Interest expense	**129,720**	128,384	**259,111**	252,091
Allowance for debt funds used during construction	**(12,722)**	(78,591)	**(46,829)**	(153,021)
Amortization of debt discount and expense	**2,794**	2,632	**5,498**	5,258
Net interest charges	**119,792**	52,425	**217,780**	104,328
Net margin	**$ 24,191**	$ 18,414	**$ 66,290**	$ 42,824

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

Oglethorpe Power Corporation
Consolidated Statements of Patronage Capital and Membership Fees (Unaudited)
For the Three Months and Six Months Ended June 30, 2024 and 2023

		(dollars in thousands)
Balance at December 31, 2022	$	1,192,127
Net margin		24,410
Balance at March 31, 2023	$	1,216,537
Net margin		18,414
Balance at June 30, 2023	$	1,234,951
Balance at December 31, 2023	$	1,257,917
Net margin		42,099
Balance at March 31, 2024	$	1,300,016
Net margin		**24,191**
Balance at June 30, 2024	**$**	**1,324,207**

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

Oglethorpe Power Corporation
Consolidated Statements of Cash Flows (Unaudited)
For the Six Months Ended June 30, 2024 and 2023

	(dollars in thousands)	
	2024	2023
Cash flows from operating activities:		
Net margin	**$ 66,290**	$ 42,824
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**279,830**	196,729
Accretion cost	**36,039**	32,230
Amortization of deferred gains	**(894)**	(894)
Allowance for equity funds used during construction	**(763)**	(307)
Deferred outage costs	**(14,385)**	(22,985)
Gain on sale of investments	**(12,996)**	(9,989)
Regulatory deferral of costs associated with nuclear decommissioning	**1,368**	(5,371)
Other	**(25,989)**	(723)
Change in operating assets and liabilities:		
Receivables	**(45,037)**	34,021
Inventories	**11,573**	(23,876)
Prepayments and other current assets	**(9,517)**	(5,886)
Accounts payable	**(19,949)**	(98,977)
Accrued interest	**(3,671)**	(22,699)
Accrued taxes	**(15,711)**	(19,844)
Other current liabilities	**(6,174)**	(55,884)
Rate management program billing credits applied	**(66,056)**	(25,185)
Other	**9,809**	(13,018)
Total adjustments	**117,477**	(42,658)
Net cash provided by operating activities	**183,767**	166
Cash flows from investing activities:		
Property additions	**(328,264)**	(495,134)
Plant acquisition	**(73,153)**	(16,743)
Activity in nuclear decommissioning trust fund—Purchases	**(713,412)**	(217,394)
—Proceeds	**705,264**	213,108
Decrease in restricted investments	**—**	74,031
Activity in long-term and short-term investments—Purchases	**(125,105)**	(95,750)
—Proceeds	**194,546**	98,756
Other	**(1,419)**	20,100
Net cash used in investing activities	**(341,543)**	(419,026)
Cash flows from financing activities:		
Long-term debt proceeds	**362,442**	38,401
Long-term debt payments	**(207,124)**	(213,972)
(Decrease) increase in short-term borrowings, net	**(134,585)**	409,237
Other	**(39,725)**	24,381
Net cash (used in) provided by financing activities	**(18,992)**	258,047
Net decrease in cash, cash equivalents and restricted cash	**(176,768)**	(160,813)
Cash, cash equivalents and restricted cash at beginning of period	**490,592**	625,781
Cash, cash equivalents and restricted cash at end of period	**$ 313,824**	$ 464,968
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 214,945**	$ 120,826
Supplemental disclosure of non-cash investing and financing activities:		
Change in asset retirement obligations	**$ 65,149**	$ 87,509
Accrued property additions at end of period	**$ 22,693**	$ 92,532

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

(A) *General.* The consolidated financial statements included in this report have been prepared by us pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the information furnished in this report reflects all adjustments (which include only normal recurring adjustments) and estimates necessary to fairly state, in all material respects, our financial condition and results of operations for the three-month and six-month periods ended June 30, 2024 and 2023. Examples of estimates used include items related to (i) our asset retirement obligations, such as closure and post-closure cost estimates, timing of expenditures, escalation factors and discount rates, and (ii) depreciation rates, such as determining the depreciable service lives. Actual results may differ from those estimates. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to SEC rules and regulations, although we believe that the disclosures are adequate to make the information presented not misleading.

These unaudited consolidated financial statements should be read in conjunction with the audited consolidated financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2023, as filed with the SEC. The results of operations for the three-month and six-month periods ended June 30, 2024 are not necessarily indicative of results to be expected for the full year. As noted in our 2023 Form 10-K, our revenues consist primarily of sales to our 38 electric distribution cooperative members and, thus, the receivables on the consolidated balance sheets are principally from our members. See "Notes to Consolidated Financial Statements" in our 2023 Form 10-K.

(B) *Fair Value.* Authoritative guidance regarding fair value measurements for financial and non-financial assets and liabilities defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles, and expands disclosures about fair value measurements.

The guidance establishes a three-tier fair value hierarchy which prioritizes the inputs used in measuring fair value as follows:

- *Level 1.* Quoted prices from active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Quoted prices in active markets provide the most reliable evidence of fair value and are used to measure fair value whenever available. Level 1 primarily consists of financial instruments that are exchange-traded.

- *Level 2.* Pricing inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Level 2 primarily consists of financial instruments that are non-exchange-traded but have significant observable inputs.

- *Level 3.* Pricing inputs that include significant inputs which are generally less observable from objective sources. These inputs may include internally developed methodologies that result in management's best estimate of fair value. Level 3 financial instruments are those whose fair value is based on significant unobservable inputs.

As required by the guidance, assets and liabilities measured at fair value are based on one or more of the following three valuation techniques:

1. *Market approach.* The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities (including a business) and deriving fair value based on these inputs.

2. *Income approach.* The income approach uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

3. *Cost approach.* The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (often referred to as current replacement cost). This approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The tables below detail assets and liabilities measured at fair value on a recurring basis at June 30, 2024 and December 31, 2023.

	Fair Value Measurements at Reporting Date Using			
		Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
	June 30, 2024	(Level 1)	(Level 2)	(Level 3)
	(dollars in thousands)			
Nuclear decommissioning trust funds:				
Domestic equity	**$ 244,363**	$ 244,363	$ —	$ —
International equity trust	**148,275**	—	148,275	—
Corporate bonds and debt	**72,196**	—	72,110	86
US Treasury securities	**46,970**	46,970	—	—
Mortgage backed securities	**57,536**	—	57,536	—
Domestic mutual funds	**88,247**	88,247	—	—
Municipal bonds	**298**	—	298	—
Federal agency securities	**8,201**	—	8,201	—
International mutual funds	**2,912**	—	2,912	—
Non-US Gov't bonds & private placements	**3,963**	—	3,963	—
Other	**13,658**	13,658	—	—
Long-term investments:				
International equity trust	**45,497**	—	45,497	—
Corporate bonds and debt	**14,544**	—	14,544	—
US Treasury securities	**16,127**	16,127	—	—
Mortgage backed securities	**16,481**	—	16,481	—
Domestic mutual funds	**353,127**	353,127	—	—
Treasury STRIPS	**181,052**	—	181,052	—
Non-US Gov't bonds & private placements	**2,494**	—	2,494	—
Other	**1,063**	1,063	—	—
Short-term investments: Treasury STRIPS	**147,156**	—	147,156	—
Natural gas swaps	**22,090**	—	22,090	—

		Fair Value Measurements at Reporting Date Using		
	December 31, 2023	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(dollars in thousands)		
Nuclear decommissioning trust funds:				
Domestic equity	$ 234,979	$ 234,979	$ —	$ —
International equity trust	134,911	—	134,911	—
Corporate bonds and debt	67,986	—	67,900	86
US Treasury securities	43,917	43,917	—	—
Mortgage backed securities	58,763	—	58,763	—
Domestic mutual funds	85,481	85,481	—	—
Municipal bonds	303	—	303	—
Federal agency securities	7,256	—	7,256	—
Non-US Gov't bonds & private placements	2,717	—	2,717	—
International mutual funds	2,012	—	2,012	—
Other	2,914	2,914	—	—
Long-term investments:				
International equity trust	43,202	—	43,202	—
Corporate bonds and debt	14,151	—	14,151	—
US Treasury securities	17,243	17,243	—	—
Mortgage backed securities	15,024	—	15,024	—
Domestic mutual funds	378,387	378,387	—	—
Treasury STRIPS	220,765	—	220,765	—
Non-US Gov't bonds & private placements	1,568	—	1,568	—
Other	392	392	—	—
Short-term investments: Treasury STRIPS	143,931	—	143,931	—
Natural gas swaps	13,445	—	13,445	—

Investments labeled Other primarily include cash and cash equivalents.

The Level 2 investments above may not be exchange traded. The fair value measurements for these investments are based on a market approach, including the use of observable inputs at or near the valuation date. Common inputs include reported trades and broker/dealer bid/ask prices. The fair value of the Level 2 investments above in international equity trust are calculated based on the net asset value per share of the fund. There are no unfunded commitments for the international equity trust and redemption may occur daily with a 3-day redemption notice period.

The Level 3 investments above in corporate bonds and debt consist of investments in bank loans which are not exchange traded. Although these securities may be liquid and priced daily, their inputs are not observable.

The estimated fair values of our long-term debt, including current maturities at June 30, 2024 and December 31, 2023 were as follows:

	2024		2023	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
	(in thousands)			
Long-term debt	**$ 12,256,419**	**$ 10,379,884**	$ 12,096,552	$ 10,638,749

The estimated fair value of long-term debt is classified as Level 2 and is estimated based on observed or quoted market prices for the same or similar issues or on current rates offered to us for debt of similar maturities. The primary sources of our long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank that is guaranteed by the Rural Utilities Service or the U.S. Department of Energy. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from a third party data reporting service, and are based on secondary market trading of our debt. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of June 30, 2024 and December 31, 2023 plus an applicable spread, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank.

For cash and cash equivalents and receivables, the carrying amount approximates fair value because of the short-term maturity of those instruments.

(C) *Derivative Instruments.* We use commodity derivatives to manage our exposure to fluctuations in the market price of natural gas. Our risk management and compliance committee provides general oversight over all derivative activities. We do not apply hedge accounting to derivative transactions, but instead apply regulated operations accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps are reflected as regulatory assets or liabilities, as appropriate. Realized gains and losses on natural gas swaps are included in fuel expense within our consolidated statements of revenues and expenses and, therefore, net margins within our consolidated statement of cash flows.

We are exposed to credit risk as a result of entering into these arrangements. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. We have established policies and procedures to manage credit risk through counterparty analysis, exposure calculation and monitoring, exposure limits, collateralization and certain other contractual provisions.

It is possible that volatility in commodity prices could cause us to have credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of June 30, 2024, all of the counterparties with transaction amounts outstanding under our derivative programs are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

We have entered into International Swaps and Derivatives Association agreements with our natural gas derivative counterparties that mitigate credit exposure by creating contractual rights relating to creditworthiness, collateral, termination and netting (which, in certain cases, allows us to use the net value of affected transactions with the same counterparty in the event of default by the counterparty or early termination of the agreement).

Additionally, we have implemented procedures to monitor the creditworthiness of our counterparties and to evaluate nonperformance in valuing counterparty positions. We have contracted with a third party to assist in monitoring certain of our counterparties' credit standing and condition. Net liability positions are generally not adjusted as we use derivative transactions as hedges and have the ability and intent to perform under each of our contracts. In the instance of net asset positions, we consider general market conditions and the observable financial health and outlook of specific counterparties, forward looking data such as credit default swaps, when available, and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

The contractual agreements contain provisions that could require us or the counterparty to post collateral or credit support. The amount of collateral or credit support that could be required is calculated as the difference between the aggregate fair value of the hedges and pre-established credit thresholds. The credit thresholds are contingent upon each party's credit ratings from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty.

Under the natural gas swap arrangements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment.

At June 30, 2024 and December 31, 2023, the estimated fair values of our natural gas contracts were net assets of approximately $22,090,000 and $13,445,000, respectively.

At June 30, 2024 and December 31, 2023, none of our counterparties was required to post credit collateral under our natural gas swap agreements.

The following table reflects the notional volume of our natural gas derivatives as of June 30, 2024 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2024	21.3
2025	25.3
2026	21.1
2027	10.4
2028	0.9
2029	1.2
Total	**80.2**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at June 30, 2024 and December 31, 2023.

	Balance Sheet Location	Fair Value	
		2024	2023
		(dollars in thousands)	
Assets:			
Natural gas swaps	Prepayments and other current assets	**$ 6,356**	$ —
Natural gas swaps	Other deferred charges	**$ 19,995**	$ 25,459
Liabilities:			
Natural gas swaps	Other current liabilities	**$ 3,869**	$ 10,370
Natural gas swaps	Other deferred credits	**$ 392**	$ 1,644

The following table presents the gross realized gains and (losses) on derivative instruments recognized in net margins for the three and six months ended June 30, 2024 and 2023.

	Statement of Revenues and Expenses Location	Three Months Ended June 30,		Six Months Ended June 30,	
		2024	2023	**2024**	2023
		(dollars in thousands)			
Natural gas swaps gains	Fuel	**$ 564**	$ 5	**$ 605**	$ 140
Natural gas swaps losses	Fuel	**(6,194)**	(7,207)	**(14,646)**	(16,604)
Total		**$ (5,630)**	$(7,202)	**$ (14,041)**	$ (16,464)

The following table presents the unrealized gains on derivative instruments deferred on the balance sheet at June 30, 2024 and December 31, 2023.

	Balance Sheet Location	2024	2023
		(dollars in thousands)	
Natural gas swaps	Regulatory liability	**$ 22,090**	$ 13,445
Total		**$ 22,090**	$ 13,445

(D) *Investment Securities.* Investment securities we hold are recorded at fair value in the accompanying consolidated balance sheets. We apply regulated operations accounting to the unrealized gains and losses of all investment securities. All realized and unrealized gains and losses are determined using the specific identification method.

The following tables summarize debt and equity securities as of June 30, 2024 and December 31, 2023.

		Gross Unrealized		
	(dollars in thousands)			
June 30, 2024	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 354,561**	**$ 279,893**	**$ (6,177)**	**$ 628,277**
Debt	**840,701**	**2,621**	**(22,189)**	**821,133**
Other	**14,734**	**113**	**(97)**	**14,750**
Total	**$ 1,209,996**	**$ 282,627**	**$ (28,463)**	**$ 1,464,160**

		Gross Unrealized		
	(dollars in thousands)			
December 31, 2023	Cost	Gains	Losses	Fair Value
Equity	$ 344,669	$ 246,795	$ (5,549)	$ 585,915
Debt	908,316	3,938	(25,181)	887,073
Other	2,889	61	(36)	2,914
Total	$ 1,255,874	$ 250,794	$ (30,766)	$ 1,475,902

The cost basis of our debt securities that were in unrealized loss positions at June 30, 2024 was $781,120,000. At June 30, 2024, $3,317,000 of the $22,189,000 of unrealized losses relates to securities that have been in unrealized loss positions for less than twelve months and $18,872,000 relates to securities that have been in unrealized loss positions for greater than twelve months. These unrealized losses are primarily attributable to increases in market interest rates.

The cost basis of our debt securities that were in unrealized loss positions at December 31, 2023 was $788,798,000. At December 31, 2023, $3,362,000 of the $25,181,000 of unrealized losses relates to securities that have been in unrealized loss positions for less than twelve months and $21,819,000 relates to securities that have been in unrealized loss positions for greater than twelve months. These unrealized losses are primarily attributable to increases in market interest rates.

(E) *Recently Issued or Adopted Accounting Pronouncements.* In November 2023, the Financial Accounting Standards Board (FASB) issued “Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures.” The amendments in this update are intended to improve reportable segment disclosure requirements, primarily through enhanced disclosures about significant expenses. The amendments in this update require disclosures to include significant segment expenses that are regularly provided to the chief operating decision maker (CODM), a description of other segment items by reportable segment, and any additional measures of a segment's profit or loss used by the CODM when deciding how to allocate resources. The amendments in this update are also applicable to entities with only one reportable segment. The amendments in this update also require all annual disclosures currently required by Topic 280 to be included in interim periods. The new standard is effective for us for annual reporting periods beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted and requires retrospective application to all prior periods presented in the financial statements. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In December 2023, the FASB amended "Income Taxes (Topic 740): Improvements to Income Tax Disclosures”. The amendments in this update requires additional disclosures related to the rate reconciliation, income taxes paid and other amendments intended to improve effectiveness and comparability. The amendments in this update are effective for us for annual periods beginning after December 15, 2024. Early adoption is permitted and should be applied on a prospective basis. Retrospective application is permitted. We are currently evaluating the future impact of this standard on our consolidated financial statements, however, we do not anticipate the impact will be significant.

(F) *Revenue Recognition.* As an electric membership cooperative, our principal business is providing wholesale electric service to our members. Our operating revenues are derived primarily from wholesale power contracts we have with each of our 38 members that extend to December 31, 2085. These contracts are substantially identical and obligate our members jointly and severally to pay all expenses associated with owning and operating our power supply business. As a cooperative, we operate on a not-for-profit basis and, accordingly, seek only to generate revenues sufficient to recover our cost of service and to generate margins sufficient to establish reasonable reserves and meet certain financial coverage requirements. We also sell energy and capacity to non-members through industry standard contracts and negotiated agreements, respectively. We do not have multiple operating segments.

Pursuant to our contracts, we primarily provide two services, capacity and energy. Capacity and energy revenues are recognized by us upon transfer of control of promised services to our members and non-members in an amount that reflects the consideration we expect to receive in exchange for those services. Capacity and energy are distinct and we account for them as separate performance obligations. The obligations to provide capacity and energy are satisfied over time as the customer simultaneously receives and consumes the benefit of these services. Both performance obligations are provided directly by us and not through a third party.

Each of our members is obligated to pay us for capacity and energy we furnish under the wholesale power contract in accordance with rates we establish. We review our rates periodically but are required to do so at least once every year. Revenues from our members are derived through a cost-plus rate structure which is set forth as a formula in the rate schedule to the wholesale power contracts. The formulary rate provides for the pass-through of our (i) fixed costs (net of any income from other sources) plus a targeted margin as capacity revenues and (ii) variable costs as energy revenues from our members. Power purchase and sale agreements between us and non-members obligate each non-member to pay us for capacity, if any, and energy furnished in accordance with the prices mutually agreed upon. Margins produced from non-member sales are included in our rate schedule formula and reduce revenue requirements from our members. As of June 30, 2024 and December 31, 2023, we did not have any significant long-term contracts with non-members.

The consideration we receive for providing capacity services is determined by our formulary rate on an annual basis. The components of the formulary rate associated with capacity costs include the annual budget of fixed costs, a targeted margin and income from other sources. Capacity revenues, therefore, vary to the extent these components vary. Fixed costs include items such as fixed operation and maintenance expenses, administrative and general expenses, depreciation and interest. Year to year, capacity revenue fluctuations are generally due to the recovery of fixed operation and maintenance expenses. Fixed costs also include certain costs, such as major maintenance costs, which will be recognized as expense in future periods. Recognition of revenues associated with these future expenses is deferred pursuant to Accounting Standards Codification (ASC) 980, Regulated Operations. The regulatory liabilities are amortized to revenue in accordance with the associated revenue deferral plan as the expenses are recognized. For information regarding regulatory accounting, see Note J.

Capacity revenues are recognized by us for standing ready to deliver electricity to our customers. Our capacity revenues are based on the associated costs we expect to recover in a given year and are generally recognized and billed to our members in equal monthly installments over the course of the year regardless of whether our generation and purchased power resources are dispatched to produce electricity. Non-member capacity revenues are billed and recognized in accordance with the terms of the associated contract.

We have a power bill prepayment program pursuant to which our members may prepay future capacity costs and receive a discount. As this program provides us with financing, we adjust our capacity revenues by the amount of the discount, which is based on our avoided cost of borrowing. For additional information regarding our member prepayment program, see Note K.

We satisfy our performance obligations to deliver energy as energy is delivered to the applicable meter points. We determine the standard selling price for energy we deliver to our members based upon the variable costs incurred to generate or purchase that energy. Fuel expense is the primary variable cost. Energy revenue recognized equals the actual variable expenses incurred in any given accounting period. Our member energy revenues fluctuate from period to period based on several factors, including fuel costs, weather and other seasonal factors, load requirements in our members' service territories, variable operating costs, the availability of electric generation resources, our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights, and by members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers. The standard selling price for our energy revenues from non-members is the price mutually agreed upon.

We are required under our first mortgage indenture to produce a margins for interest ratio of at least 1.10 for each fiscal year. For 2024, our board has approved a targeted margins for interest ratio of 1.14. Historically, our board of directors has approved adjustments to revenue requirements by year end such that revenue in excess of that required to meet the targeted margins for interest ratio is refunded to the members. Given that our capacity revenues are based upon budgeted expenditures and generally recognized and billed to our members in equal monthly installments over the course of the year, we may recognize capacity revenues that exceed our actual fixed costs and targeted margins in any given interim reporting period. At each interim reporting period we assess our projected revenue requirements through year end to determine whether a refund to our members of excess consideration is likely. If so, we reduce our capacity revenues and recognize a refund liability to our members. Refund liabilities, if any, are included in accounts payable on our unaudited consolidated balance sheets. As of June 30, 2024 and June 30, 2023, we recognized refund liabilities totaling $12,900,000 and $4,000,000, respectively. As of December 31, 2023, we recognized refund liabilities totaling

$34,266,000. Based on our current agreements with non-members, we do not refund any consideration received from non-members.

Sales to members for the three and six months ended June 30, 2024 and 2023 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	(dollars in thousands)			
	2024	2023	**2024**	2023
Capacity revenues	**$ 401,710**	$ 234,183	**$ 757,428**	$ 476,227
Energy revenues	**160,557**	131,313	**340,209**	276,922
Total	**$ 562,267**	$ 365,496	**$ 1,097,637**	$ 753,149

Receivables from contracts with our members at June 30, 2024 and December 31, 2023 were $202,176,000 and $170,901,000, respectively.

Sales to non-members during the three and six months ended June 30, 2024 and 2023 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	(dollars in thousands)			
	2024	2023	**2024**	2023
Energy revenues	**$ 1,037**	$ 20,269	**$ 1,195**	$ 21,306
Capacity revenues	**786**	3,624	**1,572**	4,387
Total	**$ 1,823**	$ 23,893	**$ 2,767**	$ 25,693

Energy revenues from non-members for the three and six months ended June 30, 2024 and June 30, 2023 were primarily from the sale of the BC Smith Energy Facility's deferring members' output into the wholesale market. For the three and six months ended June 30, 2024 and June 30, 2023, we also recognized capacity revenues from non-members related to the two units we acquired at the Washington Power Plant in December 2022. Energy revenues from non-members decreased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023 primarily due to the decrease in megawatt-hours sold to non-members as a result of a scheduled major maintenance outage at BC Smith. Capacity revenues from non-members decreased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023 primarily due to the expiration of the tolling agreement with Georgia Power Company at Washington.

The remainder of our receivables is primarily related to transactions with Georgia Power, affiliated companies and investment income. Our receivables from non-members at June 30, 2024 and December 31, 2023 were $49,883,000 and $30,883,000, respectively.

Electric capacity and energy revenues are recognized by us without any obligation for returns, warranties or taxes collected. As our members are jointly and severally obligated to pay all expenses associated with owning and operating our power supply business and we perform an on-going assessment of the credit worthiness of non-members and have not had a history of any write-offs from non-members, we have not recorded an allowance for doubtful accounts associated with our receivables from members or non-members.

We have a rate management program that ended December 2023, which allowed us to expense and recover interest costs associated with the construction of Vogtle Units No. 3 and No. 4, on a current basis, that would otherwise be deferred or capitalized. Under this program, the cumulative amounts billed to participating members was $135,693,000.

In 2018, we began an additional rate management program that allowed us to recover future expense on a current basis from our members. In general, the program allowed for additional collections over a five-year period with those amounts then applied to billings over the subsequent five-year period. The program is designed primarily as a mechanism to assist our members in managing the rate impacts associated with the commercial operation of the new Vogtle units. In December 2022, collections from our members ended for this rate management program. Under this program, billing credits to participating members during the six months ended June 30, 2024 and 2023 were $60,818,000 and $31,427,000, respectively. Funds collected through this program are invested and held until applied to members' bills. Investments that mature and are expected to be applied to members' bills within the next twelve months are included in the Short-term investments line item within our unaudited consolidated balance sheets. In conjunction with this program, we applied regulated operations accounting to defer these revenues and related investment income on the funds collected. Amounts deferred under the program are amortized to income when applied to members' bills. The cumulative amount billed, since inception of the program totaled $369,102,000. As of June 30, 2024, $252,103,000 was our remaining liability to be credited to our members' bills. For additional information regarding our revenue deferral plan, see Note J.

(G) *Leases.* As a lessee, we have a relatively small portfolio of leases with the most significant being our 60% undivided interest in Scherer Unit No. 2 and railcar leases for the transportation of coal. We also have various other leases of minimal value.

We classify our four Scherer Unit No. 2 leases as finance leases and our railcar leases as operating leases. We have made an accounting policy election not to recognize right-of-use assets and lease liabilities that arise from short-term leases, leases having an initial term of 12 months or less, for any class of underlying asset. We recognize lease expense for short-term leases on a straight-line basis over the lease term. Lease expense recognized for our short-term leases during the three and six months ended June 30, 2024 and 2023 was insignificant.

Finance Leases

Three of our Scherer Unit No. 2 finance leases have lease terms through December 31, 2027, and one lease extends through June 30, 2031. At the end of the leases, we can elect at our sole discretion to:

- Renew the leases for a period of not less than one year and not more than five years at fair market value,
- Purchase the undivided interest at fair market value, or
- Redeliver the undivided interest to the lessors.

For rate-making purposes, we include the actual lease payments for our finance leases in our cost of service. The difference between lease payments and the aggregate of the amortization on the right-of-use asset and the interest on the finance lease obligation is recognized as a regulatory asset. Finance lease amortization is recorded in depreciation and amortization expense.

Operating Leases

Our railcar operating leases have terms that extend through March 31, 2029. At the end of the railcar operating leases, we can renew at terms mutually agreeable by us and the lessors, purchase the assets or return the assets to the lessors. We have additional operating leases including one for office equipment that has a term extending through October 31, 2028 and one for real property at one of our electric generating facilities that has a term extending through February 2042 with one renewal option for a 20 year term.

The exercise of renewal options for our finance and operating leases is at our sole discretion.

As all of our operating leases do not provide an implicit rate, we use an incremental borrowing rate based on the information available at the time new lease agreements are entered into or reassessed to determine the present value of lease payments.

We combine lease and nonlease components for all lease agreements.

Classification	**June 30, 2024**	December 31, 2023
	(dollars in thousands)	
Right-of-use assets—Finance leases		
Right-of-use assets	**$ 302,732**	$ 302,732
Less: Accumulated provision for depreciation	**(280,782)**	(278,586)
Total finance lease assets	**$ 21,950**	$ 24,146
Lease liabilities—Finance leases		
Obligations under finance leases	**$ 38,520**	$ 43,586
Long-term debt and finance leases due within one year	**9,868**	9,351
Total finance lease liabilities	**$ 48,388**	$ 52,937

Classification	June 30, 2024	December 31, 2023
	(dollars in thousands)	
Right-of-use assets—Operating leases		
Electric plant in service, net	**$ 8,502**	$ 6,587
Total operating lease assets	**$ 8,502**	$ 6,587
Lease liabilities—Operating leases		
Capitalization—Other	**$ 6,588**	$ 5,152
Other current liabilities	**1,914**	1,529
Total operating lease liabilities	**$ 8,502**	$ 6,681

		Three months ended		Six months ended	
Lease Cost	Classification	June 30, 2024	June 30, 2023	June 30, 2024	June 30, 2023
		(dollars in thousands)			
Finance lease cost:					
Amortization of leased assets	Depreciation and amortization	**$ 2,338**	$ 2,100	**$ 4,676**	$ 4,199
Interest on lease liabilities	Interest expense	**1,399**	1,638	**2,799**	3,276
Operating lease cost:	Inventory[1] & production expense	**582**	328	**1,120**	657
Total leased cost		**$ 4,319**	$ 4,066	**$ 8,595**	$ 8,132

[1] The majority of our operating lease costs relate to our railcar leases and such costs are added to the cost of our fossil-fuel inventories and are recognized in fuel expense as the inventories are consumed.

	June 30, 2024	December 31, 2023
Lease Term and Discount Rate:		
Weighted-average remaining lease term (in years)		
Finance leases	**4.81**	5.26
Operating leases	**5.31**	5.77
Weighted-average discount rate:		
Finance leases	**11.05 %**	11.05 %
Operating leases	**6.34 %**	6.37 %

	Six months ended June 30,	
	2024	2023
	(dollars in thousands)	
Other Information:		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance leases	**$ 2,925**	$ 3,389
Operating cash flows from operating leases	**$ 1,214**	$ 657
Financing cash flows from finance leases	**$ 4,550**	$ 4,086
Right-of-use assets obtained in exchange for new operating lease liabilities	**$ 2,791**	$ —

Maturity analysis of our finance and operating lease liabilities as of June 30, 2024 is as follows:

	(dollars in thousands)		
Year Ending December 31,	**Finance Leases**	**Operating Leases**	**Total**
2024	$ 7,475	$ 1,236	$ 8,711
2025	14,949	2,353	17,302
2026	14,949	2,061	17,010
2027	14,949	1,784	16,733
2028	3,052	1,674	4,726
Thereafter	7,631	884	8,515
Total lease payments	$ 63,005	$ 9,992	$ 72,997
Less: imputed interest	(14,617)	(1,490)	(16,107)
Present value of lease liabilities	$ 48,388	$ 8,502	$ 56,890

As a lessor, we primarily lease office space to several tenants within our headquarters building. Several of these tenants are related parties. We account for all of these lease agreements as operating leases.

Lease income recognized during the three and six months ended June 30, 2024 and 2023 was as follows:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2024	2023	**2024**	2023
	(dollars in thousands)			
Lease income	**$ 1,392**	$ 1,691	**$ 2,779**	$ 3,376

(H) *Contingencies and Regulatory Matters.* We do not anticipate that the liabilities, if any, for any current proceedings against us will have a material effect on our financial condition or results of operations. However, at this time, the ultimate outcome of any pending or potential litigation cannot be determined.

Environmental Matters. As is typical for electric utilities, we are subject to various federal, state and local environmental laws which represent significant future risks and uncertainties. Air emissions, water discharges and water usage are extensively controlled, closely monitored and periodically reported. Handling and disposal requirements govern the manner of transportation, storage and disposal of various types of waste. We may also become subject to climate change regulations that impose restrictions on emissions of greenhouse gases, including carbon dioxide.

Such requirements may substantially increase the cost of electric service, by requiring modifications in the design or operation of existing facilities or the purchase of emission allowances. Failure to comply with these requirements could result in civil and criminal penalties and could include the complete shutdown of individual generating units not in compliance. Certain of our debt instruments require us to comply in all material respects with laws, rules, regulations and orders imposed by applicable governmental authorities, which include current and future environmental laws or regulations. Should we fail to be in compliance with these requirements, it would constitute a default under those debt instruments. We believe that we are in compliance with those environmental regulations currently applicable to our business and operations. Although it is our intent to comply with current and future regulations, we cannot provide assurance that we will always be in compliance.

At this time, the ultimate impact of any new and more stringent environmental regulations described above is uncertain and could have an effect on our financial condition, results of operations and cash flows as a result of future additional capital expenditures and increased operations and maintenance costs.

Additionally, litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the United States. In particular, personal injury and other claims for damages caused by alleged exposure to hazardous materials, and common law nuisance claims for injunctive relief, personal injury and property damage allegedly caused by coal combustion residue, greenhouse gas and other emissions have become more frequent.

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, of which we are a co-owner, has impacted groundwater, surface water, and air, resulting in alleged personal injuries and property damage. The plaintiffs seek 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 granted Georgia Power's motion to transfer the case to the Superior Court of Monroe County. In May 2023, the Superior Court of Monroe County denied Georgia Power's motion to dismiss the case for lack of subject matter jurisdiction. In July 2023, the Superior Court of Monroe County 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. The Superior Court of Monroe County has set a trial date of November 11, 2024 for the first of the approximately 44 plaintiffs.

Eight additional complaints, three on October 8, 2021, four on February 7, 2022, and one on January 9, 2023, 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 each of 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 February 2023. On May 12, 2023, the plaintiffs refiled their eight complaints in the Superior Court of Monroe County. Also on May 12, 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 seeks an unspecified amount of monetary damages, including punitive damages. On May 18, 2023, Georgia Power removed all of these cases to the U.S. District Court for the Middle District of Georgia. The plaintiffs are requesting the court remand the cases back to the Superior Court of Monroe County.

The amount of any possible losses from these matters cannot be estimated at this time.

In May 2022, Florida Power & Light Company and JEA filed a complaint in the U.S. District Court for the Northern District of Georgia against us and the other co-owners of Plant Scherer alleging that their contractual responsibility for a proportionate share of certain common facility costs relating to future environmental projects at Plant Scherer should be decreased following the retirement of Scherer Unit No. 4 at the end of 2021. We and the other co-owners of Plant Scherer filed motions to dismiss Florida Power & Light and JEA's complaint and, on February 9, 2023, the court granted our motions to dismiss with leave to amend. On March 13, 2023, Florida Power & Light and JEA filed an amended complaint and on April 17, 2023, we and the other co-owners filed motions to dismiss this amended complaint. On March 26, 2024, the court granted our motions to dismiss with leave for plaintiffs to once again amend their complaint, which the plaintiffs did not do. On April 15, 2024, the court entered an order dismissing the action and directing the clerk to close the case. Plaintiffs did not appeal that order and so the action is dismissed.

(I) *Restricted Cash and Investments.*

Restricted cash consists of collateral posted by our counterparties under our natural gas swap agreements. The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the unaudited consolidated balance sheets that sum to the total of the same such amounts reported in the unaudited consolidated statements of cash flows.

Classification	Six months ended	
	June 30, 2024	June 30, 2023
	(dollars in thousands)	
Cash and cash equivalents	**$ 313,824**	$ 459,368
Restricted cash included in restricted cash and short-term investments	—	5,600
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	**$ 313,824**	$ 464,968

(J) *Regulatory Assets and Liabilities.* We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery through future rates. We expect to recover such costs from our members in future revenues through rates under the wholesale power contracts we have with each of our members. The wholesale power contracts extend through December 31, 2085. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from our members.

The following regulatory assets and liabilities are reflected on the consolidated balance sheets as of June 30, 2024 and December 31, 2023.

	2024	2023
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt(a)	**$ 23,532**	$ 25,476
Amortization of financing leases(b)	**26,739**	28,780
Outage costs(c)	**29,776**	30,040
Asset retirement obligations—Ashpond and other(l)	**334,240**	343,523
Depreciation expense - Plant Vogtle(d)	**33,414**	34,125
Depreciation expense - Plant Wansley(e)	**325,483**	335,884
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs(f)	**55,008**	55,159
Interest rate options cost(g)	**133,859**	137,463
Deferral of effects on net margin—TA Smith Energy Facility(h)	**127,813**	130,786
Deferral of effects on net margin—BC Smith Energy Facility(p)	**18,406**	1,817
Other regulatory assets(o)	**30,257**	8,436
Total Regulatory Assets	**$1,138,527**	$1,131,489
Regulatory Liabilities:		
Accumulated retirement costs for other obligations(i)	**$ 23,134**	$ 25,992
Deferral of effects on net margin—Hawk Road Energy Facility(h)	**15,712**	16,020
Deferral of effects on net margin—BC Smith Energy Facility(p)	**—**	546
Major maintenance reserve(j)	**79,627**	120,547
Deferred debt service adder(k)	**178,591**	170,466
Asset retirement obligations—Nuclear(l)	**78,809**	47,217
Revenue deferral plan(m)	**252,103**	308,507
Natural gas hedges(n)	**22,090**	13,445
Other regulatory liabilities(o)	**1,977**	3,580
Total Regulatory Liabilities	**$ 652,043**	$ 706,320
Net Regulatory Assets	**$ 486,484**	$ 425,169

(a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt that are being amortized over the lives of the refunding debt, which range up to 20 years.

(b) Represents the difference between expense recognized for rate-making purposes versus financial statement purposes related to finance lease payments and the aggregate of the amortization of the asset and interest on the obligation.

(c) Consists of both coal-fired maintenance and nuclear refueling outage costs. Coal-fired outage costs are amortized on a straight-line basis to expense over periods up to 60 months, depending on the operating cycle of each unit. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 or 24-month operating cycles of each unit.

(d) Prior to Nuclear Regulatory Commission (NRC) approval of a 20-year license extension for Plant Vogtle, we deferred the difference between Plant Vogtle depreciation expense based on the then 40-year operating license and depreciation expense assuming an expected 20-year license extension. Amortization commenced upon NRC approval of the license extension in 2009 and is being amortized over the remaining life of the plant.

(e) Represents the deferral of accelerated depreciation associated with the early retirement of Plant Wansley, which occurred on August 31, 2022. Amortization commenced upon the retirement of Plant Wansley and will end no later than December 31, 2040.

(f) Deferred charges consist of training related costs, including interest and carrying costs of such training. Amortization commences effective with the commercial operation date of each unit and is amortized to expense over the life of the units.

(g) Deferral of premiums paid to purchase interest rate options used to hedge interest rates on certain borrowings, related carrying costs and other incidentals associated with construction of Vogtle Units No. 3 and No. 4. Amortization commenced in August 2023 after Vogtle Unit No. 3 was placed in service.

(h) Effects on net margin for TA Smith and Hawk Road Energy Facilities were deferred through the end of 2015 and are being amortized over the remaining life of each respective plant.

(i) Represents the accrual of retirement costs associated with long-lived assets for which there are no legal obligations to retire the assets.

(j) Represents collections for future major maintenance costs; revenues are recognized as major maintenance costs are incurred.

(k) Represents collections to fund certain debt payments to be made through the end of 2025 which will be in excess of amounts collected through depreciation expense; the deferred credits will be amortized over the remaining useful life of the plants.

(l) Represents the difference in the timing of recognition of decommissioning costs for financial statement purposes versus ratemaking purposes, as well as the deferral of unrealized gains and losses of funds set aside for decommissioning.

(m) Deferred revenues under a rate management program that allowed for additional collections over a five-year period which began in 2018. These amounts are being amortized to income and applied to member billings, per each members' election, over the subsequent five-year period.

(n) Represents the deferral of unrealized gains on natural gas contracts.

(o) The amortization periods for other regulatory assets range up to 30 years and the amortization periods of other regulatory liabilities range up to 3 years.

(p) Effects on net margin for the BC Smith Energy Facility that are being deferred until on or before January 2026 and will be amortized over the remaining life of the plant.

(K) *Member Power Bill Prepayments.* We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. The prepayments are being credited against members' power bills through December 2028, with the majority of the balance scheduled to be credited by the end of 2025.

(L) *Debt.*

a) *Department of Energy Loan Guarantee:*

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005, we and the U.S. Department of Energy, acting by and through the Secretary of Energy, entered into a Loan Guarantee Agreement on February 20, 2014 pursuant to which the Department of Energy agreed to guarantee our obligations under a Note Purchase Agreement, dated as of February 20, 2014 (the Original Note Purchase Agreement), among us, the Federal Financing Bank and the Department of Energy and two future advance promissory notes, each dated February 20, 2014, made by us to the Federal Financing Bank in the aggregate amount of $3,057,069,461 (the Original FFB Notes and together with the Original Note Purchase Agreement, the Original FFB Documents).

On March 22, 2019, we and the Department of Energy entered into an Amended and Restated Loan Guarantee Agreement (as amended, the Loan Guarantee Agreement) which increased the aggregate amount guaranteed by the Department of Energy to $4,676,749,167. We also entered into a Note Purchase Agreement dated as of March 22, 2019 (the Additional Note Purchase Agreement), among us, the Federal Financing Bank and the Department of Energy and a future advance promissory note, dated March 22, 2019, made by us to the Federal Financing Bank in the amount of $1,619,679,706 (the Additional FFB Note and together with the Additional Note Purchase Agreement, the Additional FFB Documents).

Together, the Original FFB Documents and Additional FFB Documents provide for a term loan facility (the Facility) under which we borrowed a total of $4,633,028,088. We received our final advance under the Facility in December 2022. Interest is payable quarterly in arrears and principal payments on all advances under the FFB Notes began on February 20, 2020. As of June 30, 2024, we have repaid $517,981,987 of principal on the FFB Notes and the aggregate Department of Energy-guaranteed borrowings outstanding, including capitalized interest, totaled $4,115,046,100. The final maturity date is February 20, 2044. We may voluntarily prepay outstanding borrowings under the Facility. Under the FFB Documents, any prepayment will be subject to a make-whole premium or discount, as applicable. Any amounts prepaid may not be re-borrowed.

Under the Loan Guarantee Agreement, we are obligated to reimburse the Department of Energy in the event it is required to make any payments to the Federal Financing Bank under its guarantee. Our payment obligations to the Federal Financing Bank under the FFB Notes and reimbursement obligations to the Department of Energy under its guarantee, but not our covenants to the Department of Energy under the Loan Guarantee Agreement, are secured equally and ratably with all of our other obligations issued under our first mortgage indenture.

Under the Loan Guarantee Agreement, we are subject to customary borrower affirmative and negative covenants and events of default. In addition, we are subject to project-related reporting requirements and other project-specific covenants and events of default.

b) *Rural Utilities Service Guaranteed Loans:*

For the six-month period ended June 30, 2024, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $12,441,000 for long-term financing of general and environmental improvements at existing plants.

In July 2024, we received an additional $6,995,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

c) *Lines of Credit:*

In May 2024, we amended our syndicated line of credit facility among eleven lenders, including National Rural Utilities Cooperative Finance Corporation, as administrative agent to extend the maturity date for five years to May 23, 2029. In connection with this amendment, we increased the available amount under the credit agreement to $1,275,000,000 from $1,210,000,000.

The renewed credit agreement contains customary representations, warranties, covenants, events of default and acceleration, including financial covenants to maintain patronage capital of at least $900,000,000, previously $750,000,000 and limits our unsecured indebtedness, as defined by the credit agreement, at $4,000,000,000. At June 30, 2024, our actual patronage capital was $1,300,000,000 and we had $473,300,000 of unsecured indebtedness outstanding.

d) Green First Mortgage Bonds:
On June 21, 2024, we issued $350,000,000 of 5.800% green first mortgage bonds, Series 2024A, to provide for long-term financing or refinancing of expenditures related to Vogtle Units No. 3 and No. 4, including refinancing principal payments on our Department of Energy-guaranteed loans that were made prior to Vogtle Unit No. 4's in-service date. In conjunction with the issuance of the bonds, we repaid $346,014,000 of outstanding commercial paper. The bonds are due to mature June 2054 and are secured under our first mortgage indenture.

(M) *Vogtle Units No. 3 and No. 4.* We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company, Inc. as its agent for licensing, engineering, procurement and contract management.

Georgia Power placed Unit No. 3 in service on July 31, 2023 and placed Unit No. 4 in service on April 29, 2024.

Our ownership interest and proportionate share of the cost to construct Vogtle Units No. 3 and No. 4 is 30%, representing approximately 660 megawatts. As of June 30, 2024, our actual costs related to the new Vogtle units were approximately $8.3 billion, net of $1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and approximately $418 million we received from Georgia Power. We estimate that our proportionate share of remaining additional capital costs to be incurred on the project through the end of 2024 to be $10-$20 million.

For additional information regarding our participation in Plant Vogtle Units No. 3 and No. 4, see Note 8 in our 2023 Form 10-K.

Plant Vogtle Unit No. 3 and No. 4 Production Tax Credits

For the six months ended June 30, 2024, we sold Georgia Power $32,800,000 of nuclear production tax credits and recognized the amount as a credit to the Production expense line item within our consolidated income statements. In 2023, we sold Georgia Power $21,700,000 of nuclear production tax credits. No credits were generated or sold during the six months ended June 30, 2023.

(N) *Measurement of Credit Losses on Financial Instruments.* The financial assets we hold that are subject to credit losses (Topic 326) are predominately accounts receivable and certain cash equivalents classified as held-to-maturity debt (e.g. commercial paper). Our receivables are generally due within thirty days or less with a significant portion related to billings to our members. See Note F for information regarding our member receivables. Commercial paper we invest in is rated as investment grade. Given our historical experience, the short duration lifetime of these financial assets and the short time horizon over which to consider expectations of future economic conditions, we have assessed that non-collection of the cost basis of these financial assets is remote and we have not recognized an allowance for credit losses.

(O) *Asset Retirement Obligations.* On February 14, 2024, Plant Vogtle Unit No. 4's nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality. During the first quarter of 2024, we recognized new nuclear asset retirement obligations totaling $65.1 million. During the six months ended June 30, 2024, no change in cash flow estimates related to existing coal ash related asset retirement obligations was recorded. We expect to periodically receive more refined estimates from Georgia Power regarding closure costs and the timing of expenditures.

(P) *Plant Acquisition.* On June 28, 2024, we completed the previously announced acquisition of Walton County Power, LLC, which owns the Walton County Power Plant, located near Monroe, Georgia, from Mackinaw Power, LLC, an affiliate of the Carlyle Group, Inc. Walton is a three-unit 465 megawatt natural gas-fired combustion turbine facility.

The purchase price was $75,418,000 and other costs associated with the transaction were approximately $2,588,000 (consisting primarily of spare parts, legal and professional services). We accounted for the acquisition as an asset acquisition. We financed the acquisition on an interim basis through the issuance of commercial paper and submitted a loan application to the Rural Utilities Service for long-term financing. For any amounts not funded through the Rural Utilities Service, we intend to issue first mortgage bonds. We expect that any financing from the Rural Utilities Service or through first mortgage bonds will be secured under our first mortgage indenture.

The following amounts represent the identifiable assets acquired and liabilities assumed in the Walton acquisition:

Classification		
		(dollars in thousands)
Recognized identifiable assets acquired and liabilities assumed:		
Electric plant in service, net	**$**	**76,730**
Other current assets		**667**
Other current liabilities		**(1,979)**
Total identifiable net assets	**$**	**75,418**

Some of our members elected to take service (scheduling members) at the date of acquisition and some members have elected to defer (deferring members) their share of output through a date no later than January 2027. Prior to the deferring members’ use of Walton, their share of output is being sold into the wholesale market. Residual net results of operations, including related interest costs of deferring members are deferred as a regulatory asset. This regulatory asset will be amortized over the then remaining life of the plant, estimated to be 25 years at January 2027. Amortization of a deferring member's share of the regulatory asset will begin upon taking service. Revenues and costs of output associated with scheduling members are being recognized in the current period.

(Q) *Subsequent Events.*

(i) We have executed precedent agreements with Southern Natural Gas Company, LLC (SONAT) that became effective in August 2024. The agreements provide for firm natural gas transportation needed to serve a new approximately 1,200 megawatt two-unit combined cycle generation facility to be constructed in Monroe County, Georgia and additional firm transportation to our BC Smith Energy Facility. The firm transportation is contingent upon completion of these expansion projects by SONAT. Total fixed charges over the 20-year base terms will be approximately $1,901,000,000. Our obligation to make payments begins when the pipeline expansion projects are placed into service, both of which are projected to be November 2028.

(ii) On June 7, 2024, the U.S. Court of Federal Claims entered a final judgment awarding damages to Georgia Power Company for spent nuclear fuel storage costs incurred at Plants Hatch and Vogtle during the period from January 1, 2011 through December 31, 2014. Our share of the award is approximately $39,000,000. All parties had until August 6, 2024 to appeal and no appeals were entered. The judgment must now be submitted by the Department of Justice to the Treasury Department for payment from the Judgment Fund, after which payment may be expected within thirty to sixty days. No amounts for the settlement have been recorded in our unaudited consolidated financial statements as of June 30, 2024. For additional information regarding claims seeking damages for spent nuclear fuel storage costs, see Note 1g in our 2023 Form 10-K.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

We are a Georgia electric membership corporation (an EMC) incorporated in 1974 and headquartered in metropolitan Atlanta. We are owned by our 38 retail electric distribution cooperative members. Our members are consumer-owned distribution cooperatives providing retail electric service in Georgia on a not-for-profit basis. Our principal business is providing wholesale electric power to our members, which we provide primarily from our generation assets and, to a lesser extent, from power purchased from other suppliers. As with cooperatives generally, we operate on a not-for-profit basis.

We have a substantially similar wholesale power contract with each member that extends to December 31, 2085, and each contract will continue thereafter until terminated by three years' written notice by us or the respective member. For additional information regarding our wholesale power contracts with our members, see "Item 1–BUSINESS–OGLETHORPE POWER CORPORATION–Wholesale Power Contracts" in our 2023 Form 10-K.

Results of Operations

<u>For the Three and Six Months Ended June 30, 2024 and 2023</u>

Net Margin

Our net margin for the three-month and six-month periods ended June 30, 2024 were $24.2 million and $66.3 million, compared to $18.4 million and $42.8 million for the same periods of 2023, respectively. Through June 30, 2024, we collected approximately 94% of our targeted net margin of $70.4 million for the year ending December 31, 2024. These collections are typical as our capacity revenues are generally recorded evenly throughout the year. We anticipate our board of directors will approve a budget adjustment by year end so that margins will achieve, but not exceed, the 2024 targeted margins for interest ratio of 1.14. As a result, we assessed our projected margin and annual revenue requirement to meet the targeted margins for interest ratio to determine if a refund liability should be recognized. As a result of this assessment, we recognized cumulative refund liabilities of $12.9 million and $4.0 million as of June 30, 2024 and June 30, 2023, respectively. For additional information regarding our net margin requirements and policy, see "Item 7–MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Summary of Cooperative Operations—*Margins*" in our 2023 Form 10-K.

Operating Revenues

Our operating revenues fluctuate from period to period based on several factors, including fuel costs, weather and other seasonal factors, load requirements in our members' service territories, operating costs, availability of electric generation resources, our decisions of whether to dispatch our owned, purchased or member-owned resources over which we have dispatch rights and our members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers, and sales to non-members.

Sales to Members. We generate revenues principally from the sale of electric capacity and energy to our members. Capacity revenues are the revenues we receive for electric service whether or not our generation and purchased power resources are dispatched to produce electricity. These revenues are designed to recover the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges, plus a targeted margin. Energy revenues are the sales of electricity generated or purchased for our members. Energy revenues recover the variable costs of our business, including fuel, purchased energy and variable operation and maintenance expense.

The components of member revenues for the three-month and six-month periods ended June 30, 2024 and 2023 were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	(dollars in thousands)			(dollars in thousands)		
	2024	2023	% Change	**2024**	2023	% Change
Capacity revenues	**$401,710**	$ 234,183	71.5 %	**$757,428**	$ 476,227	59.0 %
Energy revenues	**160,557**	131,313	22.3 %	**340,209**	276,922	22.9 %
Total	**$562,267**	$ 365,496	53.8 %	**$1,097,637**	$ 753,149	45.7 %
MWh Sales to members[1]	**7,555,404**	6,847,840	10.3 %	**14,391,964**	12,795,892	12.5 %
Cents/kWh	**7.44**	5.34	39.3 %	**7.63**	5.89	29.5 %
Member energy requirements supplied[1]	**69 %**	71 %	(2.8)%	**68 %**	68 %	0.0 %

[1] Excludes test energy megawatt-hours from Plant Vogtle Units No. 3 and No. 4 supplied to members. Any revenues and costs associated with test energy were capitalized.

Energy revenues from members increased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023, primarily due to the increase in megawatt-hours sold to members and recovery of higher fuel costs. For a discussion of fuel costs, which are the primary costs recovered by energy revenues, see "—*Operating Expenses*." Capacity revenues from members increased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023, primarily due to the recovery of increased fixed operating expenses, net interest expense and depreciation expense as a result of Plant Vogtle Units No. 3 and No. 4 being placed in service on July 31, 2023 and April 29, 2024, respectively.

Sales to non-members. Sales to non-members during the three-month and six-month periods ended June 30, 2024 and 2023 were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	(dollars in thousands)			(dollars in thousands)		
	2024	2023	% Change	**2024**	2023	% Change
Energy revenues	**$ 1,037**	$ 20,269	(94.9)%	**$ 1,195**	$ 21,306	(94.4)%
Capacity revenues	**786**	3,624	(78.3)%	**1,572**	4,387	(64.2)%
Total	**$ 1,823**	$ 23,893	(92.4)%	**$ 2,767**	$ 25,693	(89.2)%
MWh Sales to non-members	**48,436**	686,073	(92.9)%	**53,501**	725,288	(92.6)%
Cents/kWh	**3.76**	3.48	8.0 %	**2.23**	3.54	(37.0)%

Energy revenues from non-members were primarily from the sale of the BC Smith Energy Facility's deferring members' output into the wholesale market. Energy revenues from non-members decreased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023 primarily due to the decrease in megawatt-hours sold to non-members as a result of a scheduled major maintenance outage at BC Smith. Capacity revenues from non-members are related to the two units we acquired at the Washington Power Plant in December 2022. Capacity revenues from non-members decreased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023 primarily due to the expiration of a tolling agreement with Georgia Power Company at Washington on May 31, 2024.

Operating Expenses

Fuel

The following table summarizes our fuel costs and megawatt-hour generation by generating source.

	Cost (dollars in thousands)			Generation[1] (MWh)			Cents per kWh		
	Three Months Ended June 30,			Three Months Ended June 30,			Three Months Ended June 30,		
Fuel Source	**2024**	2023	% Change	**2024**	2023	% Change	**2024**	2023	% Change
Coal	**$ 37,256**	$ 27,055	37.7%	**850,450**	707,866	20.1%	**4.38**	3.82	14.7%
Nuclear	**31,578**	18,353	72.1%	**3,825,767**	2,618,379	46.1%	**0.83**	0.70	18.6%
Gas:									
Combined Cycle	**60,445**	70,703	(14.5)%	**2,608,445**	3,700,110	(29.5)%	**2.32**	1.91	21.5%
Combustion Turbine	**19,184**	16,357	17.3%	**507,398**	502,256	1.0%	**3.78**	3.26	16.0%
	$ 148,463	$ 132,468	12.1%	**7,792,060**	7,528,611	3.5%	**1.91**	1.76	8.5%

	Cost (dollars in thousands)			Generation[1] (MWh)			Cents per kWh		
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,		
Fuel Source	**2024**	2023	% Change	**2024**	2023	% Change	**2024**	2023	% Change
Coal	**$ 75,790**	$ 49,843	52.1%	**1,832,847**	1,286,208	42.5%	**4.14**	3.88	6.7%
Nuclear	**55,573**	34,395	61.6%	**6,874,365**	4,828,648	42.4%	**0.81**	0.71	14.1%
Gas:									
Combined Cycle	**157,286**	162,389	(3.1)%	**5,542,835**	7,026,532	(21.1)%	**2.84**	2.31	22.9%
Combustion Turbine	**26,860**	19,009	41.3%	**593,916**	579,915	2.4%	**4.52**	3.28	37.8%
	$ 315,509	$ 265,636	18.8%	**14,843,963**	13,721,303	8.2%	**2.13**	1.94	9.8%

[1] Excludes test energy megawatt-hours generated at Plant Vogtle Units No. 3 and No. 4.

Total fuel costs increased for the three-month and six-month periods ended June 30, 2024 compared to the same periods in 2023 as a result of an increase in generation for members and an increase in the average cost of fuel. The increase in generation was primarily due to Plant Vogtle Units No. 3 and No. 4 being placed in service on July 31, 2023 and April 29, 2024, respectively. The increase in average fuel cost was primarily due to a shift in generation to our coal-fired units from our relatively more economical combined cycle units due in part to the management of our coal inventory and planned major maintenance outages at our combined cycle units during the three-month and six-month periods ended June 30, 2024.

Production Expenses

Production costs increased for the three-month and six-month periods ended June 30, 2024 as compared to the same periods of 2023 as a result of $41.4 million and $53.7 million higher fixed major maintenance outage costs associated with our combined cycle plants. Production costs also increased as a result of $13.7 million and $29.4 million in production costs related to Plant Vogtle Units No. 3 and No. 4 for the respective three-month and six-month periods. Production costs for the new Vogtle units are net of $20.7 million and $32.8 million in credits recognized during the respective periods from the sale of nuclear production tax credits to Georgia Power Company.

Depreciation and Amortization Expenses

Depreciation and amortization increased for the three-month and six-month periods ended June 30, 2024 as compared to the same periods in 2023 primarily as a result of $29.6 million and $50.1 million in depreciation expense for the three-month and six-month periods ended June 30, 2024, respectively, related to Plant Vogtle Units No. 3 and No. 4 being placed in service.

Interest Charges
Net interest charges increased for the three-month and six-month periods ended June 30, 2024 as compared to the same periods in 2023 as a result of lower capitalization of interest expense due to Plant Vogtle Units No. 3 and No. 4 being placed in service.

Financial Condition

Balance Sheet Analysis as of June 30, 2024

Assets

Electric plant in service increased by approximately $3.4 billion with a corresponding decrease of $3.0 billion in construction work in progress, primarily due to Plant Vogtle Unit No. 4 being placed in service. Cash used for property additions for the six-month period ended June 30, 2024 totaled $401.4 million. Of this amount, $80.7 million was associated with construction expenditures for Vogtle Unit No. 4 and $51.0 million was for nuclear fuel purchases and $73.2 million for the Walton acquisition. The remainder was for expenditures related to normal additions and replacements to our existing generation facilities. For additional information regarding the Walton acquisition, see Note P of Notes to Unaudited Consolidated Financial Statements.

The $45.4 million increase in the nuclear decommissioning trust fund was primarily due to the increase in the fair market value of investments due to continued appreciation in the stock market during the six-month period ended June 30, 2024.

Long-term investments decreased $60.3 million for the six-month period ended June 30, 2024, primarily due to $124.0 million redeemed to fund major maintenance outages expenses and to fund expenses associated with our revenue deferral rate management plan, which was designed primarily to assist our members in managing the rate impacts associated with the new Vogtle units. Largely offsetting these decreases was a $37.0 million increase in funds invested, including reinvestment of earnings, and a $14.4 million increase in fair market value. See Notes F and J of Notes to Unaudited Consolidated Financial Statements for a discussion of our member rate management programs and regulatory liabilities.

Receivables increased $50.3 million for the six-month period ended June 30, 2024 primarily due to a $34.8 million increase in member receivables and an $8.7 million increase in receivables from Georgia Power.

Inventories decreased $27.1 million during the six-month period ended June 30, 2024 primarily due to a decrease in fuel inventories of $13.6 million due to increased generation at our coal-fired units and the associated increase in coal burn and a decrease of $13.5 million in material and supplies due to the deferral of inventory costs resulting in the recognition of a $15.3 million regulatory asset.

Prepayments and other current assets increased $15.9 million during the six-month period ended June 30, 2024 primarily due to a $6.4 million increase in the fair value of our natural gas hedges and a $3.5 million increase in prepayments related to future major maintenance outage costs at our natural gas-fired facilities.

Equity and Liabilities

Long-term debt and long-term debt and finance leases due within one year increased $158.2 million primarily as a result of the issuance of $350.0 million of Series 2024A green first mortgage bonds and $12.4 million in advances under one of our Rural Utilities Service-guaranteed loans. Offsetting these increases was $202.6 million in debt service payments. See Note L of Notes to Unaudited Consolidated Financial Statements for additional information regarding long-term debt.

Short-term borrowings, which primarily provide interim financing for Vogtle Units No. 3 and No. 4 construction costs, decreased $134.6 million during the six-month period ended June 30, 2024. During this period, repayments totaled $363.1 million and total short-term borrowings were $228.5 million.

Accounts payable decreased $36.4 million during the six-month period ended June 30, 2024. The decrease was primarily due to applying $34.3 million in credits to our members' bills in the first quarter of 2024 for a board-approved reduction in 2023 revenue in excess of the requirement to meet the 2023 targeted net margin.

Asset retirement obligations increased $92.6 million for the six-month period ended June 30, 2024 primarily due to recognized nuclear asset retirement obligations of $65.1 million due to Plant Vogtle Unit No. 4's nuclear reactor achievement of self-sustaining nuclear fission and $36.0 million in accretion expense.

Regulatory liabilities decreased $54.3 million for the six-month period ended June 30, 2024 primarily due to a net $56.4 million decrease in the liability for our revenue deferral rate management plan, which is associated with the new Vogtle units, and a net $40.9 million decrease in the liability for collections of future major maintenance outage costs. Offsetting these decreases was a $31.6 million increase in deferred nuclear asset retirement obligations that was primarily driven by an increase in unrealized gains associated with our nuclear decommissioning investments and an $8.6 million increase in the liability associated with unrealized gains on our natural gas contracts. See Notes F and Note J of Notes to Unaudited Consolidated Financial Statements for a discussion of our member rate management programs and regulatory liabilities.

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. Pursuant to this agreement, Georgia Power has designated Southern Nuclear Operating Company, Inc. as its agent for licensing, engineering, procurement and contract management.

Georgia Power placed Unit No. 3 in service on July 31, 2023 and placed Unit No. 4 in service on April 29, 2024.

Our ownership interest and proportionate share of the cost to construct Vogtle Units No. 3 and No. 4 is 30%, representing approximately 660 megawatts. As of June 30, 2024, our actual costs related to the new Vogtle units were approximately $8.3 billion, net of $1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and approximately $418 million we received from Georgia Power. We estimate that our proportionate share of remaining additional capital costs to be incurred on the project through the end of 2024 to be $10-$20 million.

See "Item 1 – BUSINESS – OUR POWER SUPPLY RESOURCES – Future Power Resources – *Vogtle Units No. 3 and No. 4"* in our annual report on Form 10-K for the fiscal year ended December 31, 2023 for additional information regarding our participation in Plant Vogtle Units No. 3 and No. 4.

Other Future Power Resources

As a result of projected load growth in Georgia, we and our members have approved the development and construction of two new natural gas-fired generation resources. One of the projects is an approximately 1,200 megawatt two-unit combined cycle generation facility to be located on land we own adjacent to the Smarr Energy Facility in Monroe County, Georgia. Our preliminary cost estimate for this facility is approximately $1.8 billion and the projected commercial operation date is 2029. The other project is an approximately 240 megawatt combustion turbine unit to be constructed at our Talbot Energy Facility in Talbot County, Georgia. Our preliminary cost estimate for this unit is approximately $360 million and the projected commercial operation date is 2029. In connection with these additional resources, we entered into agreements to provide firm capacity on new natural gas pipeline infrastructure to meet our anticipated fuel supply needs. We and our members may also continue to consider additional generation beyond these resources in the future.

Capital Expenditures. As part of our ongoing capital planning, we forecast expenditures required for generating facilities and other capital projects. The table below details these forecasts for 2024 through 2026. Actual expenditures may vary from the estimates listed in the table because of factors such as changes in business conditions, design changes and rework required by regulatory bodies, delays in obtaining necessary regulatory approvals, construction delays, changing environmental requirements, and changes in cost of capital, equipment, material and labor.

Capital Expenditures(1)
(dollars in millions)

	2024	2025	2026	Total
Future Generation(2)	$ 223	$ 533	$ 382	$ 1,138
Existing Generation(3)	431	446	238	1,115
Environmental Compliance(4)	14	19	31	64
Nuclear Fuel	133	121	140	394
General Plant	11	9	4	24
Total	$ 812	$ 1,128	$ 795	$ 2,735

(1) Includes allowance for funds used during construction.

(2) Primarily relates to construction of our two new natural gas-fired generation facilities. Forecasted expenditures for these two projects are based on assumed in-service dates in 2029.

(3) Normal additions and replacements to plant in-service.

(4) Pollution control equipment and facilities being installed at coal-fired Plant Scherer, including to comply with coal ash regulations.

In addition to the amounts included in the table above, we expect capital expenditures of approximately $900 million to be incurred beyond 2026 for our future natural gas-fired generation projects, which are projected to be placed in service in 2029.

Plant Acquisition

On June 28, 2024, we acquired Walton County Power, LLC, which owns the Walton Power Plant, located near Monroe, Georgia, from Mackinaw Power, LLC, an affiliate of the Carlyle Group, Inc. Walton is a three-unit 465 megawatt natural gas-fired combustion turbine facility. See Note P of Notes to Unaudited Consolidated Financial Statements for additional information about this acquisition.

Grid Resilience and Innovation Partnerships (GRIP) Program

On October 18, 2023, the Georgia Environmental Finance Authority, together with application partners Oglethorpe, Georgia Transmission Corporation and Georgia System Operations Corporation, announced that they had been selected for a $250 million grant under the Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program. As part of the grant application, Oglethorpe applied for an aggregate of 75 megawatts of utility-scale battery storage which is estimated to utilize approximately $80 million of the total award. Receipt of any grant proceeds is subject to meeting program requirements and customary closing conditions and the ultimate projects financed with these funds may change from the initial application.

Environmental Regulations

Federal and state laws and regulations regarding environmental matters affect operations at our facilities. For a discussion regarding potential effects on our business from environmental regulations, including potential capital requirements, see "Item 1—BUSINESS—REGULATION—Environmental," "Item 1A—RISK FACTORS" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2023 Form 10-K and "Risk Factors" in our quarterly report on Form 10-Q for the quarterly period ended March 31, 2024.

On April 25, 2024, the Environmental Protection Agency issued a final rule to regulate carbon dioxide (CO2) emissions from fossil-fueled electric generating units under section 111 of the Clean Air Act (CAA). The primary focus of EPA's final rule is to (i) establish emission guidelines for states to set CO2 performance standards for existing coal-fired generating units and other fossil-fueled steam generating units that burn oil and natural gas under section 111 (d) of the Clean Air Act; and (ii) revise the new source performance standards for CO2 emissions from new and reconstructed stationary combustion turbines that burn natural gas and/or other fossil fuels under section 111 (b) of the CAA. We expect that the final rule is likely to have a significant impact on the power sector and we are reviewing the final rule to determine its impact on our operations. We believe that key assumptions in the rule, particularly regarding resource adequacy, availability and timing of required infrastructure and permitting, carbon capture and sequestration and the pace of technological advancements, continue to be unrealistic. A number of industry groups, electric generators and states have challenged the final rule in the U.S. Circuit Court of Appeals for the D.C. Circuit. On July 19, 2024, the U.S. Circuit Court of Appeals for the D.C. Circuit denied motions to stay the new rule pending judicial review. Several of the parties seeking to stay the rule have filed emergency stay applications to the U.S. Supreme Court. The ultimate impact of the rule will not be known until these legal challenges are complete. At this time, we cannot predict the outcome or potential cost of this rule, but such costs could be significant.

EPA issued three additional final rules on April 25, 2024. Respectively, the rules had the effect of (i) revising effluent limitation guidelines for wastewater streams at coal-fired power plants, (ii) revising the Mercury and Air Toxics Standards (MATS) for coal-fired power plants and (iii) establishing new requirements for legacy coal combustion residuals. The revised MATS rules are not expected to have a significant impact on our operations. We are reviewing the other two final rules and their ultimate impact on us remains subject to any legal challenges and cannot be determined at this time.

Liquidity

On May 23, 2024, we amended our syndicated line of credit among eleven lenders, including National Rural Utilities Cooperative Finance Corporation, as administrative agent to extend the maturity date for five years to May 23, 2029. In connection with this amendment, we increased the available amount under the credit agreement to $1.275 billion from $1.21 billion.

At June 30, 2024, we had $1.7 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $314 million in cash and cash equivalents, and $1.4 billion available under our $1.9 billion of committed credit arrangements, the details of which are reflected in the table below:

Committed Credit Facilities			
	Authorized Amount	Available June 30, 2024	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line among 11 banks led by CFC(1)	$ 1,275	$ 799	May 2029
CFC Line of Credit(2)	110	110	December 2028
JPMorgan Chase Line of Credit(3)	350	347	October 2024
Secured Facilities:			
CFC Term Loan(2)	250	140	December 2028

(1) This facility is dedicated to support outstanding commercial paper and the portion of this facility that was unavailable represents outstanding commercial paper at June 30, 2024.

(2) Any amounts drawn under the $110 million unsecured line of credit with CFC will reduce the amount that can be drawn under the $250 million secured term loan. Therefore, we reflect $140 million as the amount available under the term loan even though there are no amounts outstanding under that facility. Any amounts borrowed under the $250 million term loan would be secured under our first mortgage indenture, with a maturity no later than December 31, 2043.

(3) At June 30, 2024, $2.5 million of this facility was used for letters of credit issued to provide performance assurance to third parties. We anticipate renewing this line of credit in the third quarter of 2024.

We have the flexibility to use the $1.275 billion syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up commercial paper.

Under our commercial paper program, we are authorized to issue commercial paper in amounts that do not exceed the amount of our committed backup lines of credit, thereby providing 100% dedicated support for any commercial paper outstanding. Due to this requirement, any commercial paper we issue will reduce the availability under the $1.275 billion syndicated line of credit. At June 30, 2024, our outstanding commercial paper primarily was used to provide interim funding for:

- payments related to the construction of Vogtle Units No. 3 and No. 4,
- principal payments made under our Department of Energy-guaranteed loans, from February 2020 prior to the commercial operation date of Vogtle Unit 4, and
- costs related to the Washington, Baconton and Walton acquisitions.

We plan to refinance our commercial paper with long-term debt. We intend to issue first mortgage bonds to provide long-term financing of the construction costs for Vogtle Units No. 3 and No. 4 that have been financed on an interim basis with commercial paper, refinancing of the principal payments we paid under our Department of Energy-guaranteed loans prior to commercial operation of Vogtle Unit No. 4, and for certain other costs not financed through the Rural Utilities Service. Rural Utilities Service financing is our preferred source of long-term financing for the Washington, Baconton and Walton acquisitions. In May 2024, we closed new Rural Utilities Service-guaranteed loans for the Washington and Baconton acquisitions.

Our unsecured committed lines of credit permit the issuance of up to $960 million in letters of credit on our behalf, of which $957 million remained available at June 30, 2024. This letter of credit issuance capacity includes $500 million under our $1.275 billion syndicated line of credit, $350 million under our JPMorgan Chase line of credit, and $110 million under our CFC line of credit.

Three of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At June 30, 2024, the highest required minimum level was $900 million and our actual patronage capital was $1.3 billion. Two of these agreements contain an additional covenant that limits our unsecured indebtedness, as defined in the credit agreements, to $4 billion, and one of these agreements contains an additional covenant that limits our secured indebtedness, as defined in the credit agreements, to $14 billion. At June 30, 2024, we had $12.3 billion of secured indebtedness and $473 million of unsecured indebtedness outstanding.

Under our power bill prepayment program, members can prepay their power bills from us at a discount for an agreed number of months in advance, after which point the funds are credited against the participating members' monthly power bills. At June 30, 2024, we had six members participating in the program and a balance of $88.3 million remaining to be applied against future power bills.

Financing Activities

First Mortgage Indenture. At June 30, 2024, we had $12.3 billion of long-term debt outstanding under our first mortgage indenture secured equally and ratably by a lien on substantially all of our owned tangible and certain of our intangible property, including property we acquire in the future. See "Item 1—BUSINESS—OGLETHORPE POWER CORPORATION—First Mortgage Indenture" in our 2023 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. A summary of our Rural Utilities Service-Guaranteed Loans as of June 30, 2024 is provided in the table below:

Approved Rural Utilities Service-Guaranteed Loans			
	Amount Approved	**Amount Advanced June 30, 2024**	**Amount Remaining June 30, 2024**
	(dollars in millions)		
General and Environmental Improvements	$ 630.3	$ 448.3	$ 182.0
General and Environmental Improvements	755.2	—	755.2
Washington Acquisition	87.9	—	87.9
Baconton Acquisition	17.5	—	17.5
Total	$ 1,490.9	$ 448.3	$ 1,042.6

In May 2024, we closed on the three loans in the table above that have not been advanced. We expect to begin advancing on these loans in late 2024. When advanced, the debt will be secured ratably under our first mortgage indenture. As of June 30, 2024, we had $2.6 billion of debt outstanding under various Rural Utilities Service-guaranteed loans.

Department of Energy-Guaranteed Loans. We have loans from the Federal Financing Bank guaranteed by the Department of Energy that provided funding for over $4.6 billion of the cost to construct our interest in Vogtle Units No. 3 and No. 4. Under the Department of Energy-guaranteed loans we have $4.1 billion outstanding at June 30, 2024. All of the debt advanced under the loan guarantee agreement is secured ratably with all other debt under our first mortgage indenture.

In accordance with the promissory notes, we began principal repayments of our Department of Energy-guaranteed loans in February 2020. As of June 30, 2024, we had repaid $518.0 million under these loans. We refinanced a portion of this amount by issuing green first mortgage bonds in June 2024.

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For more information regarding the loan guarantee agreement, see Note L of Notes to Unaudited Consolidated Financial Statements. For more detailed information regarding our financing plans, see "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities*" in our 2023 Form 10-K.

Bond Financings. On June 21, 2024, we issued $350 million of 5.80% green first mortgage bonds, Series 2024A, for the purpose of refinancing commercial paper we had issued to refinance Department of Energy guaranteed loans that matured prior to the commercial operation date of Vogtle Unit 4. In conjunction with the issuance of the bonds, we repaid $346 million of outstanding commercial paper. The bonds are due to mature in June 2054 and are secured under our first mortgage indenture.

We plan to issue approximately $350-$450 million of additional taxable first mortgage bonds in late 2024 or early 2025 to provide long-term financing or refinancing of expenditures related to Vogtle Units No. 3 and No. 4, including up to $350 million for the remaining long-term financing for the Vogtle units and up to $100 million, which, in addition to the $350 million that we issued in June 2024, will be used to refinance a portion of the $486 million of principal payments on our Department of Energy-guaranteed loans that were made prior to Vogtle Unit No. 4's in-service date.

Newly Adopted or Issued Accounting Standards

For a discussion of recently issued or adopted accounting pronouncements, see Note E of Notes to Unaudited Consolidated Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes to the market risks disclosed in "Item 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK" in our 2023 Form 10-K.

Item 4. Controls and Procedures

As of June 30, 2024, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

There have been no changes in internal control over financial reporting or other factors that occurred during the quarter ended June 30, 2024 that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

The ultimate outcome of pending litigation against us cannot be predicted at this time; however, we do not anticipate that the ultimate liabilities, if any, arising from such proceedings would have a material effect on our financial condition or results of operations. For information about loss contingencies, including litigation related to Plant Scherer, of which we are a co-owner, that could have an effect on us, see Note H to Unaudited Consolidated Financial Statements.

Item 1A. Risk Factors

We are subject to construction risks for additional projects we are undertaking to meet projected load growth in Georgia.

Georgia is projected to experience a significant increase in energy demand, including large loads, over the next several years. As a result of this load growth, we and our members have approved the development and construction of two new natural gas-fired generation resources. One of the projects is an approximately 1,200 megawatt two-unit combined cycle generation facility to be located on land we own adjacent to the Smarr Energy Facility in Monroe County, Georgia. Our preliminary cost estimate for this facility is approximately $1.8 billion and the projected commercial operation date is 2029. The other project is an approximately 240 megawatt combustion turbine unit to constructed at our Talbot Energy Facility. Our preliminary cost estimate for this unit is approximately $360 million and the projected commercial operation date is 2029. In connection with these additional resources, we entered into agreements to provide firm capacity on new natural gas pipeline infrastructure to meet our anticipated fuel supply needs. We and our members may also continue to consider additional generation resources in the future.

Loads of 900 kilowatts or more in Georgia are subject to competition at initial operation, and our members may be selected to meet some of the additional large loads in their service territories. We and our members will use the best information we have available to us to appropriately plan for our members' anticipated power needs. If our members' actual load growth is significantly lower than projected, costs related to any new facilities could increase the cost of electric service we provide to those members more than anticipated and could affect their ability to perform their contractual obligations to us.

Our development and construction of new generating resources and the construction of new natural gas pipeline infrastructure capacity by third-parties to serve these resources is subject to construction risk. We will also be subject to construction risks for capital projects to comply with current or future environmental standards. Many factors could lead to cost increases and schedule delays for any of these projects, including:

- cost and availability of labor;
- challenges related to contractors or vendors;
- contractor and subcontractor performance;
- timing and issuance of necessary permits or approvals (including required certificates from regulatory agencies);
- shortages, delays, increased costs or inconsistent quality of materials and equipment;
- performance under construction agreements and contract disputes;
- the cost and availability of debt financing, including the availability of federal loan or grant programs, increased interest rates or increased funding costs as a result of construction schedule delays;

- catastrophic events, natural disasters and future pandemic health events; and
- weather conditions.

Failure to complete any construction project on schedule and on budget for any reason could increase the cost of electric service we provide to our members and, as a result, could affect their ability to perform their contractual obligations to us.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not Applicable.

Item 3. Defaults upon Senior Securities

Not Applicable.

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

Michael L. Smith Announces January 2025 Retirement

On August 14, 2024, Michael L. Smith, our President and Chief Executive Officer, announced his planned retirement at the end of January 2025. Mr. Smith has served as our President and Chief Executive Officer since November 2013 and expects to continue in his current role through January 2025 to ensure the orderly transfer of responsibilities to a successor President and Chief Executive Officer. Our board of directors intends to promptly commence a search for a new President and Chief Executive Officer.

On August 14, 2024, we issued a press release regarding Mr. Smith's planned retirement. The press release is furnished herewith as Exhibit 99.2.

Rule 10b5-1 Trading Arrangements

During the fiscal quarter ended June 30, 2024, none of our directors or "officers," as defined in Rule 16a-1(f) under the Securities Exchange Act of 1934, adopted or terminated any "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as those terms are defined in Item 408 of Regulation S-K. As noted on the cover page of this quarterly report on Form 10-Q, we are a membership corporation and have no authorized or outstanding equity securities although we do have outstanding debt securities.

Item 6. Exhibits

Number	Description
4.1	Thirteenth Amended and Restated Loan Contract, dated as of May 30, 2024, between Oglethorpe and the United States of America.
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Michael L. Smith (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Michael L. Smith (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).
99.1	Member Financial and Statistical Information (for calendar years 2021-2023).
99.2	Press Release, dated August 14, 2024.
101	XBRL Interactive Data File.
104	Cover Page Interactive Data File, formatted in Inline XBRL.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Oglethorpe Power Corporation
(An Electric Membership Corporation)

Date: August 14, 2024	By:	/s/ Michael L. Smith
		Michael L. Smith President and Chief Executive Officer
Date: August 14, 2024		/s/ Elizabeth B. Higgins
		Elizabeth B. Higgins Executive Vice President and Chief Financial Officer (Principal Financial Officer)