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, 2023

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, 2023

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, 2022 and under "Risk Factors" and in other sections of 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 the construction of Unit No. 4 at Plant Vogtle and closure of coal ash ponds;
- the resolution of any disputes between two or more of the Vogtle co-owners, including the current litigation regarding certain cost-mitigation provisions under the ownership participation agreement;
- decisions made by the Georgia Public Service Commission in the regulatory process related to the two additional units at Plant Vogtle;
- a decision by Georgia Power Company to cancel Vogtle Unit No. 4 or a decision by more than 10% of the co-owners of Unit No. 4 not to proceed with the construction upon the occurrence of certain material adverse events;
- 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 occurrence of certain events that give the Department of Energy the option to require that we repay all amounts outstanding under the loan guarantee agreement with the Department of Energy over a five-year period and its decision to require such repayment;
- 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;
- early retirement of our co-owned coal facilities;
- 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;
- acts of sabotage, wars or terrorist activities, including cyber attacks;
- 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;
- future variants of the current coronavirus ("COVID-19") and any resulting economic disruption and its impact on our business, financial condition, operations, construction projects, including at Plant Vogtle, and our members and their service territories;
- 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;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- significant changes in critical accounting policies material to us;
- 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; 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, 2023 and December 31, 2022

	(dollars in thousands)	
	2023	2022
Assets		
Electric plant:		
In service	**$ 9,445,734**	$ 9,266,627
Right-of-use assets—finance leases	**302,732**	302,732
Less: Accumulated provision for depreciation	**(5,288,246)**	(5,183,589)
Electric plant in service, net	**4,460,220**	4,385,770
Nuclear fuel, at amortized cost	**397,574**	388,303
Construction work in progress	**8,057,892**	7,716,035
Total electric plant	**12,915,686**	12,490,108
Investments and funds:		
Nuclear decommissioning trust fund	**598,357**	540,716
Investment in associated companies	**78,320**	78,937
Long-term investments	**657,779**	669,479
Other	**33,503**	32,561
Total investments and funds	**1,367,959**	1,321,693
Current assets:		
Cash and cash equivalents	**459,368**	595,381
Restricted cash and short-term investments	**5,600**	104,431
Short-term investments	**90,147**	61,702
Receivables	**179,775**	220,015
Inventories, at average cost	**322,255**	297,951
Prepayments and other current assets	**31,699**	51,409
Total current assets	**1,088,844**	1,330,889
Deferred charges and other assets:		
Regulatory assets	**1,198,819**	1,212,305
Prepayments to Georgia Power Company	**6,260**	20,873
Other	**51,334**	113,502
Total deferred charges	**1,256,413**	1,346,680
Total assets	**$ 16,628,902**	$ 16,489,370

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

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
June 30, 2023 and December 31, 2022

	(dollars in thousands)	
	2023	2022
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 1,234,951**	$ 1,192,127
Long-term debt	**11,350,650**	11,512,513
Obligation under finance leases	**48,388**	52,937
Obligation under Rocky Mountain transactions	**28,888**	27,945
Other	**1,825**	2,256
Total capitalization	**12,664,702**	12,787,778
Current liabilities:		
Long-term debt and finance leases due within one year	**315,213**	322,102
Short-term borrowings	**1,064,888**	655,650
Accounts payable	**129,252**	203,705
Accrued interest	**82,753**	105,452
Member power bill prepayments, current	**44,047**	54,443
Other current liabilities	**83,299**	153,941
Total current liabilities	**1,719,452**	1,495,293
Deferred credits and other liabilities:		
Asset retirement obligations	**1,458,257**	1,343,743
Member power bill prepayments, non-current	**51,255**	53,877
Regulatory liabilities	**719,364**	792,190
Other	**15,872**	16,489
Total deferred credits and other liabilities	**2,244,748**	2,206,299
Total equity and liabilities	**$ 16,628,902**	$ 16,489,370

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, 2023 and 2022

(dollars in thousands)

	Three Months		Six Months	
	2023	2022	**2023**	2022
Operating revenues:				
Sales to members	**$ 365,496**	$ 478,782	**$ 753,149**	$ 896,231
Sales to non-members	**23,893**	54,346	**25,693**	57,339
Total operating revenues	**389,389**	533,128	**778,842**	953,570
Operating expenses:				
Fuel	**132,468**	263,121	**265,636**	428,605
Production	**99,412**	113,387	**192,879**	209,167
Depreciation and amortization	**73,015**	70,830	**145,689**	141,756
Purchased power	**17,785**	17,661	**35,415**	34,536
Accretion	**16,722**	13,860	**32,230**	27,392
Total operating expenses	**339,402**	478,859	**671,849**	841,456
Operating margin	**49,987**	54,269	**106,993**	112,114
Other income:				
Investment income	**17,943**	12,825	**34,325**	24,672
Other	**2,909**	3,095	**5,834**	6,125
Total other income	**20,852**	15,920	**40,159**	30,797
Interest charges:				
Interest expense	**128,384**	111,595	**252,091**	216,264
Allowance for debt funds used during construction	**(78,591)**	(62,497)	**(153,021)**	(119,270)
Amortization of debt discount and expense	**2,632**	2,924	**5,258**	5,770
Net interest charges	**52,425**	52,022	**104,328**	102,764
Net margin	**$ 18,414**	$ 18,167	**$ 42,824**	$ 40,147

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 and Six Months Ended June 30, 2023 and 2022

		(dollars in thousands)
Balance at December 31, 2021	$	1,130,423
Net margin		21,980
Balance at March 31, 2022	$	1,152,403
Net margin		18,167
Balance at June 30, 2022	$	1,170,570
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**

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, 2023 and 2022

	(dollars in thousands)	
	2023	2022
Cash flows from operating activities:		
Net margin	**$ 42,824**	$ 40,147
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**196,729**	203,299
Accretion cost	**32,230**	27,392
Amortization of deferred gains	**(894)**	(894)
Allowance for equity funds used during construction	**(307)**	(291)
Deferred outage costs	**(22,985)**	(23,107)
(Gain) loss on sale of investments	**(9,989)**	18,467
Regulatory deferral of costs associated with nuclear decommissioning	**(5,371)**	(33,956)
Other	**(723)**	642
Change in operating assets and liabilities:		
Receivables	**34,021**	(123,344)
Inventories	**(23,876)**	(21,933)
Prepayments and other current assets	**(5,886)**	(20,532)
Accounts payable	**(98,977)**	17,584
Accrued interest	**(22,699)**	(16,253)
Accrued taxes	**(19,844)**	35,915
Other current liabilities	**(55,884)**	64,929
Member power bill prepayments	**(13,018)**	(12,478)
Rate management program (disbursements) collections	**(25,185)**	13,960
Total adjustments	**(42,658)**	129,400
Net cash provided by operating activities	**166**	169,547
Cash flows from investing activities:		
Property additions	**(495,134)**	(526,406)
Plant acquisition	**(16,743)**	—
Activity in nuclear decommissioning trust fund—Purchases	**(217,394)**	(199,140)
—Proceeds	**213,108**	195,557
Decrease in restricted investments	**74,031**	184,812
Activity in other long-term investments—Purchases	**(95,750)**	(134,310)
—Proceeds	**98,756**	102,982
Other	**20,100**	2,615
Net cash used in investing activities	**(419,026)**	(373,890)
Cash flows from financing activities:		
Long-term debt proceeds	**38,401**	792,503
Long-term debt payments	**(213,972)**	(256,747)
Increase (decrease) in short-term borrowings, net	**409,237**	(334,689)
Other	**24,381**	14,493
Net cash provided by financing activities	**258,047**	215,560
Net (decrease) increase in cash, cash equivalents and restricted cash	**(160,813)**	11,217
Cash, cash equivalents and restricted cash at beginning of period	**625,781**	581,150
Cash, cash equivalents and restricted cash at end of period	**$ 464,968**	$ 592,367
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 120,826**	$ 112,365
Supplemental disclosure of non-cash investing and financing activities:		
Change in asset retirement obligations	**$ 87,509**	$ —
Accrued property additions at end of period	**$ 92,532**	$ 64,476
Bond purchase fund included in cash, cash equivalents and restricted cash at end of period	**$ —**	$ 30,975

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

Oglethorpe Power Corporation

Notes to Unaudited 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, 2023 and 2022. 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, 2022, as filed with the SEC. The results of operations for the three-month and six-month periods ended June 30, 2023 are not necessarily indicative of results to be expected for the full year. As noted in our 2022 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 2022 Form 10-K.

During the quarter ended June 30, 2023, we identified a misstatement in the amounts presented in the net cash flows (used in) provided by operating activities and net cash flow used in investing activities presented in the unaudited Consolidated Statement of Cash Flows for the three months ended March 31, 2023. The error resulted in a $26,100,000 understatement of the depreciation and amortization, including nuclear fuel adjustment included in adjustments to reconcile net margin to net cash provided by operating activities section of the cash flows from operating activities and an offsetting $26,100,000 understatement of cash used for property additions included in cash flows from investing activities. After correction of this misstatement the balances presented for the quarter ended March 31, 2023 were as follows:

		(dollars in thousands)
Depreciation and amortization, including nuclear fuel	$	**92,645**
Net cash used in operating activities		**(64,810)**
Property additions		**(285,233)**
Net cash used in investing activities		**(200,535)**

The errors identified did not have any impact on the overall change in cash, cash equivalents and restricted cash and did not affect the unaudited Consolidated Balance Sheets or the unaudited Consolidated Statements of Revenues and Expenses for any periods presented. The misstatement was corrected in the unaudited Consolidated Statements of Cash Flows for the six months ended June 30, 2023 and we do not believe the error is material to the consolidated financial statements taken as a whole.

(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, 2023 and December 31, 2022.

	Fair Value Measurements at Reporting Date Using			
		Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs
	June 30, 2023	(Level 1)	(Level 2)	(Level 3)
	(dollars in thousands)			
Nuclear decommissioning trust funds:				
Domestic equity	**$ 217,632**	$ 217,632	$ —	$ —
International equity trust	**128,828**	—	128,828	—
Corporate bonds and debt	**67,669**	—	67,614	55
US Treasury securities	**54,112**	54,112	—	—
Mortgage backed securities	**39,314**	—	39,314	—
Domestic mutual funds	**73,435**	73,435	—	—
Federal agency securities	**7,565**	—	7,565	—
International mutual funds	**717**	—	717	—
Non-US Gov't bonds & private placements	**2,730**	—	2,730	—
Other	**6,355**	6,054	301	—
Long-term investments:				
International equity trust	**38,629**	—	38,629	—
Corporate bonds and debt	**12,273**	—	12,273	—
US Treasury securities	**16,803**	16,803	—	—
Mortgage backed securities	**13,495**	—	13,495	—
Domestic mutual funds	**334,003**	334,003	—	—
Treasury STRIPS	**240,747**	—	240,747	—
Non-US Gov't bonds & private placements	**1,751**	—	1,751	—
Other	**78**	78	—	—
Short-term investments: Treasury STRIPS	**90,147**	—	90,147	—
Natural gas swaps	**49,235**	—	49,235	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2022	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	$ 204,129	$ 204,129	$ —	$ —
International equity trust	111,266	—	111,266	—
Corporate bonds and debt	60,806	—	60,788	18
US Treasury securities	49,775	49,775	—	—
Mortgage backed securities	41,210	—	41,210	—
Domestic mutual funds	57,348	57,348	—	—
Federal agency securities	2,037	—	2,037	—
Non-US Gov't bonds & private placements	2,890	—	2,890	—
International mutual funds	653	—	653	—
Other	10,602	10,602	—	—
Long-term investments:				
International equity trust	33,606	—	33,606	—
Corporate bonds and debt	10,473	—	10,473	—
US Treasury securities	15,488	15,488	—	—
Mortgage backed securities	12,113	—	12,113	—
Domestic mutual funds	302,302	302,302	—	—
Treasury STRIPS	293,281	—	293,281	—
Non-US Gov't bonds & private placements	1,976	—	1,976	—
Other	240	240	—	—
Short-term investments: Treasury STRIPS	61,702	—	61,702	—
Natural gas swaps	131,804	—	131,804	—

The Level 2 investments above in corporate bonds and debt, federal agency securities, and mortgage backed securities 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, 2023 and December 31, 2022 were as follows:

	2023		2022	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
	(in thousands)			
Long-term debt	**$ 11,768,875**	**$ 10,214,166**	$ 11,940,359	$ 10,194,954

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, 2023 and December 31, 2022 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. Restricted investments consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account and the carrying amount of these investments approximates fair value because of the liquid nature of the deposits with the U.S. Treasury.

(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, 2023, 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, 2023 and December 31, 2022, the estimated fair values of our natural gas contracts were net assets of approximately $49,235,000 and $131,804,000, respectively.

At June 30, 2023 and December 31, 2022, one of our counterparties was required to post credit collateral totaling $5,600,000 and $30,400,000, respectively, under our natural gas swap agreements. Such posted collateral is classified as restricted cash and included in the Restricted cash and short-term investments line item within our unaudited consolidated balance sheets.

The following table reflects the notional volume of our natural gas derivatives as of June 30, 2023 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2023	19.8
2024	30.5
2025	25.0
2026	20.3
2027	7.7
Total	**103.3**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at June 30, 2023 and December 31, 2022.

	Balance Sheet Location	Fair Value	
		2023	2022
		(dollars in thousands)	
Assets:			
Natural gas swaps	Other current assets	**$ 9,688**	$ 35,285
Natural gas swaps	Other deferred charges	**$ 44,681**	$ 99,725
Liabilities:			
Natural gas swaps	Other current liabilities	**$ 5,115**	$ 3,206
Natural gas swaps	Other deferred credits	**$ 19**	$ —

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, 2023 and 2022.

	Statement of Revenues and Expenses Location	Three Months Ended June 30,		Six Months Ended June 30,	
		2023	2022	**2023**	2022
		(dollars in thousands)			
Natural gas swaps gains	Fuel	**$ 5**	$42,563	**$ 140**	$ 50,641
Natural gas swaps losses	Fuel	**(7,207)**	(203)	**(16,604)**	(282)
Total		**$ (7,202)**	$42,360	**$ (16,464)**	$ 50,359

The following table presents the unrealized gains on derivative instruments deferred on the balance sheet at June 30, 2023 and December 31, 2022.

	Balance Sheet Location	**2023**	2022
		(dollars in thousands)	
Natural gas swaps	Regulatory liability	**$ 49,235**	$ 131,804
Total		**$ 49,235**	$ 131,804

(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, 2023 and December 31, 2022.

		Gross Unrealized (dollars in thousands)		
June 30, 2023	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 330,886**	**$ 209,975**	**$ (6,023)**	**$ 534,838**
Debt	**843,576**	**1,057**	**(39,246)**	**805,387**
Other	**6,006**	**59**	**(7)**	**6,058**
Total	**$ 1,180,468**	**$ 211,091**	**$ (45,276)**	**$ 1,346,283**

		Gross Unrealized (dollars in thousands)		
December 31, 2022	Cost	Gains	Losses	Fair Value
Equity	$ 323,907	$ 159,445	$ (8,949)	$ 474,403
Debt	833,035	372	(46,369)	787,038
Other	10,445	20	(9)	10,456
Total	$ 1,167,387	$ 159,837	$ (55,327)	$ 1,271,897

(E) *Recently Issued or Adopted Accounting Pronouncements.* As of June 30, 2023, we have implemented all applicable new accounting standards and updates issued by the Financial Accounting Standards Board (FASB) that were in effect. There were no applicable standards or updates during the six months ended June 30, 2023 that had a material impact on our consolidated financial statements.

(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. These contracts, which extend to December 31, 2050, 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 have short-term energy sales to non-members made through industry standard contracts. 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, 2023 and December 31, 2022, 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. For the six-month periods ended June 30, 2023 and 2022, we provided approximately 68% and 58% of our members' energy requirements, respectively. 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 2023, 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, 2023 and June 30, 2022, we recognized refund liabilities totaling $4,000,000 and $5,000,000, respectively. As of December 31, 2022, we recognized refund liabilities totaling $28,471,000. 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, 2023 and 2022 were as follows:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	(dollars in thousands)			
	2023	2022	**2023**	2022
Capacity revenues	**$ 234,183**	$ 241,841	**$ 476,227**	$ 485,132
Energy revenues	**131,313**	236,941	**276,922**	411,099
Total	**$ 365,496**	$ 478,782	**$ 753,149**	$ 896,231
Member energy requirements supplied	**71 %**	59 %	**68 %**	58 %

Receivables from contracts with our members at June 30, 2023 and December 31, 2022 were $139,422,000 and $187,401,000, respectively.

Sales to non-members during the three and six months ended June 30, 2023 and 2022 were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	(dollars in thousands)			
	2023	2022	**2023**	2022
Energy revenues	**$ 20,269**	$ 54,346	**$ 21,306**	$ 57,339
Capacity revenues	**3,624**	—	**4,387**	—
Total	**$ 23,893**	$ 54,346	**$ 25,693**	$ 57,339

Receivables from the sale of electricity to non-members were $6,951,000 at June 30, 2023 and $8,787,000 at December 31, 2022 and are primarily from the sale of the Bobby C. Smith Jr. Energy Facility's deferring members' output. In May 2023, our Effingham Energy Facility was renamed the Bobby C. Smith Jr. Energy Facility in honor of our late board chairman. The remainder of our receivables is primarily related to transactions with affiliated companies and investment income which were $32,793,000 and $13,834,000 at June 30, 2023 and December 31, 2022, respectively.

Energy revenues from non-members for the three and six months ended June 30, 2023 were primarily from the sale of the Bobby C. Smith Jr. deferring members' output into the wholesale market. For the three and six months ended June 30, 2023, we recognized capacity revenues from non-members related to the two units we acquired at the Washington County Power Plant in December 2022. For additional information regarding the Washington County acquisition, see Note 14 in our 2022 Form 10-K.

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 allows 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. The subscribing members of Vogtle Units No. 3 and No. 4 can elect to participate in this program on an annual basis. Under this program, amounts billed to participating members during the six months ended June 30, 2023 and 2022 were $4,050,000 and $9,440,000, respectively. The cumulative amount billed since inception of the program totaled $130,482,000.

In 2018, we began an additional rate management program that allows us to recover future expense on a current basis from our members. In general, the program allows 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. During the first quarter of 2022, we began applying billing credits to some of our participating members within this program. Under this program, net billing credits and amounts billed to participating members, during the six months ended June 30, 2023 and 2022 were $31,427,000 and $5,887,000, 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 are applying regulated operations accounting to defer these revenues and related investment income on the funds collected. Amounts deferred under the program will be amortized to income when applied to members' bills. The net cumulative amount billed, since inception of the program totaled $337,675,000. 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, 2023 and 2022 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 October 31, 2026. 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 an additional operating lease that has a term that extends 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.

For lease agreements entered into or reassessed after the adoption of the new leases standard, we combine lease and nonlease components.

Classification	**June 30, 2023**	December 31, 2022
	(dollars in thousands)	
Right-of-use assets—Finance leases		
Right-of-use assets	**$ 302,732**	$ 302,732
Less: Accumulated provision for depreciation	**(275,512)**	(272,876)
Total finance lease assets	**$ 27,220**	$ 29,856
Lease liabilities—Finance leases		
Obligations under finance leases	**$ 48,388**	$ 52,937
Long-term debt and finance leases due within one year	**8,861**	8,398
Total finance lease liabilities	**$ 57,249**	$ 61,335

Classification	**June 30, 2023**	December 31, 2022
	(dollars in thousands)	
Right-of-use assets—Operating leases		
Electric plant in service, net	**$ 2,734**	$ 3,326
Total operating lease assets	**$ 2,734**	$ 3,326
Lease liabilities—Operating leases		
Capitalization—Other	**$ 1,825**	$ 2,256
Other current liabilities	**1,003**	1,164
Total operating lease liabilities	**$ 2,828**	$ 3,420

Lease Cost	Classification	Three months ended June 30, 2023	Three months ended June 30, 2022	Six months ended June 30, 2023	Six months ended June 30, 2022
		(dollars in thousands)			
Finance lease cost:					
Amortization of leased assets	Depreciation and amortization	**$ 2,100**	$ 1,886	**$ 4,199**	$ 3,771
Interest on lease liabilities	Interest expense	**1,638**	1,852	**3,276**	3,704
Operating lease cost:	Inventory[1] & production expense	**328**	222	**657**	444
Total leased cost		**$ 4,066**	$ 3,960	**$ 8,132**	$ 7,919

[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, 2023	December 31, 2022
Lease Term and Discount Rate:		
Weighted-average remaining lease term (in years)		
Finance leases	**5.72**	5.94
Operating leases	**6.87**	6.44
Weighted-average discount rate:		
Finance leases	**11.05 %**	11.05 %
Operating leases	**5.63 %**	5.52 %

	Six months ended June 30, 2023	Six months ended June 30, 2022
	(dollars in thousands)	
Other Information:		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance leases	**$ 3,389**	$ 3,806
Operating cash flows from operating leases	**$ 657**	$ 444
Financing cash flows from finance leases	**$ 4,086**	$ 3,669
Right-of-use assets obtained in exchange for new operating lease liabilities	**$ —**	$ —

Maturity analysis of our finance and operating lease liabilities as of June 30, 2023 is as follows:

Year Ending December 31,	Finance Leases	Operating Leases	Total
	(dollars in thousands)		
2023	$ 7,475	$ 667	$ 8,142
2024	14,949	850	15,799
2025	14,949	641	15,590
2026	14,949	350	15,299
2027	14,949	72	15,021
Thereafter	10,685	868	11,553
Total lease payments	$ 77,956	$ 3,448	$ 81,404
Less: imputed interest	(20,707)	(620)	(21,327)
Present value of lease liabilities	$ 57,249	$ 2,828	$ 60,077

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, 2023 and 2022 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	**2023**	2022
	(dollars in thousands)			
Lease income	**$ 1,691**	$ 1,669	**$ 3,376**	$ 3,314

(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 proposed or potential 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. On May 9, 2023, the Superior Court of Monroe County denied Georgia Power's motion to dismiss the case for lack of subject matter jurisdiction. On July 27, 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. As of the date of this quarterly report, this case has approximately 48 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 and the announced retirement of Unit No. 3 at the end of 2028. 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. While we do not believe that the co-ownership agreements support the arguments raised by Florida Power & Light Company and JEA, if their arguments were to be successful in this case, we could be responsible for an increased percentage of these costs relating to our interests in Scherer Unit Nos. 1 and 2. The amount of additional costs relating to these future projects, if any, cannot be determined at this time.

(I) *Restricted Cash and Investments.* Restricted investments consisted of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account that were held by the U.S. Treasury, acting through the Federal Financing Bank. At December 31, 2022, we had restricted investments totaling $74,031,000, all of which were classified as current. During the three-month period ended March 31, 2023, we utilized all of our restricted investments for scheduled Rural Utilities Service-guaranteed Federal Financing Bank debt service payments. No restricted investments were held at June 30, 2023.

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, 2023	June 30, 2022
	(dollars in thousands)	
Cash and cash equivalents	**$ 459,368**	$ 476,792
Bond purchase fund	—	30,975
Restricted cash included in restricted cash and short-term investments	**5,600**	84,600
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	**$ 464,968**	$ 592,367

(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, 2050. 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, 2023 and December 31, 2022.

	2023	2022
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt(a)	**$ 27,485**	$ 29,494
Amortization of financing leases(b)	**30,344**	31,908
Outage costs(c)	**36,043**	29,317
Asset retirement obligations—Ashpond and other(l)	**376,122**	353,212
Asset retirement obligations—Nuclear(l)	**—**	32,192
Depreciation expense - Plant Vogtle(d)	**34,838**	35,549
Depreciation expense - Plant Wansley(e)	**351,734**	361,784
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs(f)	**55,669**	54,701
Interest rate options cost(g)	**139,539**	136,827
Deferral of effects on net margin—Smith Energy Facility(h)	**133,758**	136,730
Other regulatory assets(o)	**13,287**	10,591
Total Regulatory Assets	**$1,198,819**	$1,212,305
Regulatory Liabilities:		
Accumulated retirement costs for other obligations(i)	**$ 34,296**	$ 35,580
Deferral of effects on net margin—Hawk Road Energy Facility(h)	**16,328**	16,636
Deferral of effects on net margin—Bobby C. Smith Jr. Energy Facility(p)	**6,941**	14,825
Major maintenance reserve(j)	**94,395**	74,584
Amortization of financing leases(b)	**4,108**	5,557
Deferred debt service adder(k)	**162,516**	154,514
Asset retirement obligations—Nuclear(l)	**19,520**	—
Revenue deferral plan(m)	**330,949**	357,460
Natural gas hedges(n)	**49,235**	131,804
Other regulatory liabilities(o)	**1,076**	1,230
Total Regulatory Liabilities	**$ 719,364**	$ 792,190
Net Regulatory Assets	**$ 479,455**	$ 420,115

(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 21 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 will commence effective with the commercial operation date of each unit and 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 on July 31, 2023.

(h) Effects on net margin for 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 will be 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 27 years and the amortization periods of other regulatory liabilities range up to 4 years.

(p) Effects on net margin for the Bobby C. Smith Jr. 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 2024.

(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, 2023, we have repaid $393,577,094 of principal on the FFB Notes and the aggregate Department of Energy-guaranteed borrowings outstanding, including capitalized interest, totaled $4,239,450,994. 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.

If certain events occur, referred to as an "Alternate Amortization Event," at the Department of Energy's option we will be required to repay the outstanding principal amount of all borrowings under the Facility over a period of five years, with level principal amortization. These events include (i) abandonment of the Vogtle Units No. 3 and No. 4 project, including a decision by Georgia Power to cancel the project, (ii) cessation of the construction of Vogtle Units No. 3 and No. 4 for twelve consecutive months, (iii) termination of the Services Agreement or rejection of the Services Agreement in bankruptcy, if Georgia Power does not maintain access to certain related intellectual property rights, (iv) termination of the Services Agreement by Westinghouse or termination of the Bechtel Agreement by Bechtel Power Corporation, (v) delivery of certain notices by the Co-owners to the Department of Energy of their intent to cancel construction of Vogtle Units No. 3 and No. 4 coupled with termination by the Co-owners of the Services Agreement or the Bechtel

Agreement, (vi) failure of the Co-owners to enter into a replacement contract with respect to the Services Agreement or the Bechtel Agreement following the Co-owners' termination of such agreement with the intent to replace it, (vii) the Department of Energy's takeover of construction of Vogtle Units No. 3 and No. 4 under certain conditions, (viii) the occurrence of any Project Adverse Event that results in a cancellation of the Vogtle Units No. 3 and No. 4 project or the cessation or deferral of construction beyond the periods permitted under the Loan Guarantee Amendment, (ix) loss of or failure to receive necessary regulatory approvals under certain circumstances, (x) loss of access to intellectual property rights necessary to construct or operate Vogtle Units No. 3 and No. 4 under certain circumstances, (xi) our failure to fund our share of operation and maintenance expenses for Vogtle Units No. 3 and No. 4 for twelve consecutive months, (xii) change of control of Oglethorpe and (xiii) certain events of loss or condemnation. If we receive proceeds from an event of condemnation relating to Vogtle Units No. 3 and No. 4, such proceeds must be applied to immediately prepay outstanding borrowings under the Facility.

b) Rural Utilities Service Guaranteed Loans:

For the six-month period ended June 30, 2023, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $38,401,000 for long-term financing of general and environmental improvements at existing plants.

In July 2023, we received an additional $19,900,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

c) Pollution Control Revenue Bonds:

On February 1, 2023, we remarketed $99,785,000 of Series 2017 pollution control revenue bonds. The remarketed bonds bear interest at an indexed rate until February 1, 2028 and are scheduled to mature in 2045. Our payment obligations related to these bonds are secured under our first mortgage indenture.

(M) *Vogtle Units No. 3 and No. 4 Construction Project.* 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 under construction 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, contract management, construction and pre-operation services.

In 2008, Georgia Power, acting for itself and as agent for the Co-owners, entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with Westinghouse Electric Company LLC and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (collectively, Westinghouse). Pursuant to the EPC Agreement, Westinghouse agreed to design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle.

Until March 2017, construction on Units No. 3 and No. 4 continued under the substantially fixed price EPC Agreement. In March 2017, Westinghouse filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Effective in July 2017, Georgia Power, acting for itself and as agent for the other Co-owners, and Westinghouse entered into a services agreement (the Services Agreement), pursuant to which Westinghouse is providing facility design and engineering services, procurement and technical support and staff augmentation on a time and materials cost basis. The Services Agreement provides that it will continue until the start-up and testing of Vogtle Units No. 3 and No. 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Co-owners upon 30 days' written notice.

In October 2017, Georgia Power, acting for itself and as agent for the other Co-owners, entered into a construction completion agreement with Bechtel Power Corporation, pursuant to which Bechtel serves as the primary contractor for the remaining construction activities for Vogtle Units No. 3 and No. 4 (the Bechtel Agreement) and is reimbursed for actual costs plus a base fee and an at-risk fee, subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Co-owner is severally, and not jointly, liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Co-owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Co-owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel

Agreement under certain circumstances, including certain Co-owner suspensions of work, certain breaches of the Bechtel Agreement by the Co-owners, Co-owner insolvency and certain other events.

Cost and Schedule

Our current budget for our ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs and allowance for funds used during construction, is $8.115 billion and is based on commercial operation dates of July 2023 and March 2024 for Units No. 3 and No. 4, respectively. This budget reflects our June 17, 2022 exercise of the tender option in the Global Amendments to the Joint Ownership Agreements as described below. Had we not exercised the tender option, our budget would be approximately $8.67 billion. At June 30, 2023, our total capital and financing costs for our interest in the additional Vogtle units was $8.4 billion, approximately $300 million of which relates to costs that exceed the tender option threshold that is the subject of litigation between us and Georgia Power, as described below.

The table below shows our project budget and actual costs through June 30, 2023 for our share of the project.

	(in millions)	
	Project Budget	Actual Costs at June 30, 2023
Construction Costs [1]	$ 6,559	$ 6,393
Freeze Capital Credit [2]	(532)	—
Financing Costs	2,038	1,925
Subtotal	$ 8,065	$ 8,318 [3]
Deferred Training Costs	47	47
Total Project Costs Before Contingency	$ 8,112	$ 8,365
Oglethorpe Contingency	$ 3	$ —
Totals	$ 8,115	$ 8,365

[1] Construction costs are net of $1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and $99 million in cost sharing benefits associated with the Global Amendments to the Joint Ownership Agreements.

[2] As described below, we exercised the tender option to cap our capital costs at the EAC in VCM 19 plus $2.1 billion, the freeze tender threshold. The freeze capital credit reflects our share of budgeted amounts that exceed this threshold.

[3] At June 30, 2023, approximately $300 million relates to costs that exceed the tender option threshold that is the subject of litigation between us and Georgia Power.

Any schedule extension beyond March 2024 for Unit No. 4 is expected to increase our financing costs by approximately $10-$15 million per month for Unit No. 4. We and some of our members have implemented various rate management programs to lessen the impact on rates related to the additional Vogtle units.

Our initial ownership interest and proportionate share of the cost to construct the additional Vogtle units was 30%, representing approximately 660 megawatts. However, we have exercised the tender option discussed below which caps our capital costs in exchange for a proportionate reduction of our 30% interest in the two units. Based on the current project budget and schedule and our interpretation of the Global Amendments (described below), we would transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share would decline from 30% to approximately 27.5%. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced.

On March 6, 2023, the Unit No. 3 nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality, and, on April 1, 2023, the generator successfully synchronized to the power grid and generated electricity for the first time. Georgia Power placed Unit No. 3 in service on July 31, 2023.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts for Unit No. 4 on a regular basis to incorporate current information available, particularly in the areas of start-up testing and related test results, engineering support, commodity installations, system turnovers and workforce statistics.

Since March 2020, the number of active cases of COVID-19 at the site has fluctuated consistent with the surrounding area and impacted productivity levels and pace of activity completion. As of June 30, 2023, the incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity, substantially all of which occurred during 2020 and 2021, is estimated by Georgia Power to be approximately $440 million, or approximately $130 million based on our initial 30% share, and is included in the project budget.

On May 1, 2023, hot functional testing was completed at Unit No. 4. On July 20, 2023, Southern Nuclear announced that all Unit No. 4 inspections, tests, analyses, and acceptance criteria documentation had been submitted to the Nuclear Regulatory Commission, and, on July 28, 2023, the Nuclear Regulatory Commission published its 103(g) finding that the accepted criteria in the combined license for Unit No. 4 had been met, which allows nuclear fuel to be loaded and start-up testing to begin. Georgia Power has disclosed that it projects an in-service date for Unit No. 4 during late fourth quarter 2023 or during the first quarter 2024. Given the remaining work to be done and potential risks associated with completing the work, our current budget anticipates an in-service date for Unit No. 4 in March 2024. Meeting the projected in-service date for Unit No. 4 significantly depends on maintaining overall construction productivity and production levels, particularly in completing remaining subcontractor scopes of work while reducing the level of craft laborers based on work remaining. As Unit No. 4 completes construction and transitions further into testing, ongoing and potential future challenges include the pace and quality of remaining commodities installations; the management of contractors and vendors, subcontractor performance, the availability of materials and parts, and/or related cost escalation; the pace of remaining work package closures; and the availability of craft, supervisory and technical support resources; and the timeframe and duration of final component and pre-operational testing.

New challenges also may continue to arise as Unit No. 4 moves further into testing and start-up, which may result in required engineering changes or remediation related to plant systems, structures or components (some of which are based on new technology that only within the last few years began initial operation in the global nuclear industry at this scale). These challenges may result in further schedule delays and/or cost increases.

There have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to ensure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction.

With the receipt of the Nuclear Regulatory Commission's 103(g) findings for Units No. 3 and No. 4 in August 2022 and July 2023, respectively, the site is subject to the Nuclear Regulatory Commission's operating reactor oversight process and must meet applicable technical and operational requirements contained in its operating license. Various design and other licensing-based compliance matters may result in additional license amendment requests or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

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

Co-Owner Contracts and Other Information

In November 2017, the Co-owners entered into an amendment to their joint ownership agreements for Vogtle Units No. 3 and No. 4 to provide for, among other conditions, additional Co-owner approval requirements. These joint ownership agreements, including the Co-owner approval requirements, were subsequently amended, effective August 31, 2018. As described below, certain provisions of the Joint Ownership Agreements were modified further on September 26, 2018 by the Term Sheet that was memorialized on February 18, 2019 when the Co-owners entered into certain amendments (the Global Amendments) to the Joint Ownership Agreements (as amended, the Joint Ownership Agreements).

As a result of an increase in the total project capital cost forecast and Georgia Power's decision not to seek recovery of its allocation of the increase in the base capital costs and the increased construction budget in connection with Georgia Power's nineteenth Vogtle construction monitoring report (VCM 19) in 2018, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 were required to vote to continue construction. In September 2018, the Co-owners unanimously voted to continue construction of Vogtle Units No. 3 and No. 4.

In connection with the September 2018 vote to continue construction, Georgia Power entered into a binding term sheet with the other Co-owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, and MEAG Power SPVP, LLC to mitigate certain financial exposure for the other Co-owners and offered to purchase production tax credits from each of the other Co-Owners, at that Co-owner's option (the Term Sheet). On February 18, 2019, the Co-owners entered into the Global Amendments to memorialize the provisions of the Term Sheet. Pursuant to the Global Amendments and consistent with the Term Sheet, the Joint Ownership Agreements provide that:

- each Co-owner is obligated to pay its proportionate share of construction costs for Vogtle Units No. 3 and No. 4 based on its ownership interest up to (i) the estimated cost at completion ("EAC") for Vogtle Units No. 3 and No. 4 which formed the basis of Georgia Power's forecast of $8.4 billion in Georgia Power's VCM 19 filed with the Georgia Public Service Commission plus (ii) $800 million of additional construction costs;

- Georgia Power will be responsible for 55.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $800 million to $1.6 billion (resulting in up to $80 million of potential additional costs to Georgia Power which would save Oglethorpe up to $44 million), with the remaining Co-owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests (equal to 24.5% for our 30% ownership interest); and

- Georgia Power will be responsible for 65.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $1.6 billion to $2.1 billion (resulting in up to a further $100 million of potential additional costs to Georgia Power which would save Oglethorpe up to an additional $55 million), with the remaining Co-owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests (equal to 19.0% for our 30% ownership interest).

If the EAC is revised and exceeds the EAC in VCM 19 by more than $2.1 billion, each of the Co-owners, other than Georgia Power, has a one-time option to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Co-owner's share of construction costs actually incurred in excess of the EAC in VCM 19 plus $2.1 billion. If any Co-owner elects to exercise this tender option, Georgia Power would have the option to cancel the project in lieu of accepting the offer to purchase a portion of the Co-owner's ownership interest. If Georgia Power does not elect to cancel the project, then Georgia Power must accept the offer, and the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the percentage of the cumulative amount of construction costs paid by such tendering Co-owner as of the commercial operation date of Vogtle Unit No. 4. For purposes of this calculation, payments made by Georgia Power on behalf of the tendering Co-owner in accordance with the second and third bullets above will be treated as payments made by that Co-owner. This option to tender a portion of our interest to Georgia Power upon such a budget increase allowed us to freeze our construction budget associated with the Vogtle project in exchange for a proportionate reduction of our 30% ownership interest.

The VCM 19 total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. As of December 31, 2021, budget increases since VCM 19 reached $3.4 billion for all Co-owners. As a result of those increases, we believe that the tender option was triggered at the Co-owner construction budget vote on February 14, 2022 and that Georgia Power's increased responsibility for certain construction costs as described above commenced in March 2022.

On June 17, 2022, we notified Georgia Power of our election to exercise the tender option and cap our capital costs in exchange for a proportionate reduction of our 30% interest in the two new units. Our decremental ownership interest will be calculated and conveyed to Georgia Power after both Vogtle units are placed in service. Based on the current project budget, our schedule assumptions and our interpretation of the Global Amendments, our project budget is $8.1 billion and we expect to transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share will decline from 30% to approximately 27.5%. By exercising the tender option and based on current assumptions, we estimate that we will avoid incurring approximately $535 million in construction costs associated with the project. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced. On July 26, 2022, the City of Dalton notified Georgia Power that it had elected to exercise its tender option.

We and Georgia Power do not agree on certain aspects of the tender option, including the dollar amount that triggers our option to tender a portion of our ownership interest to Georgia Power under the tender option or the extent to which costs that are the result of a force majeure event (such as COVID-19) impact the point at which the tender option is triggered. For purposes of determining when our option to tender was triggered, the Global Amendments do not exclude costs resulting from force majeure events (such as COVID-19) from the calculation of when the EAC in VCM 19 plus $2.1 billion has been reached. We and Georgia Power also do not agree on the dollar amount that triggered Georgia Power's increased responsibility for certain construction costs as described above, and the extent to which costs that are the result of a force majeure event (such as COVID-19), impact the calculation of the point at which Georgia Power's increased responsibility for certain construction costs as described above was triggered. The exclusion of costs resulting from a force majeure event (such as COVID-19) in the Global Amendments only applies to Georgia Power's increased cost responsibility during the time period when construction costs exceed the EAC in VCM 19 by $800 million to $2.1 billion.

Accordingly, in March 2022, we notified Georgia Power of a billing dispute with regards to both the starting dollar amount and the application of costs resulting from a force majeure event and how such amounts impact the thresholds and timing of the cost-sharing and tender option provisions. On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County, Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim against us seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power's related financial obligations. Based on the current project budget and Georgia Power's interpretation of the Global Amendments, our project budget would be $8.67 billion, and we would incur approximately $535 million of additional construction costs (excluding related financing costs) and retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

Pursuant to the Joint Ownership Agreements, as amended by the Global Amendments, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Global Amendment provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more from the seventeenth VCM report estimated in-service dates of November 2021 and November 2022 for Units No. 3 and No. 4, respectively (each, a Project Adverse Event). The schedule extensions, announced in February 2022, which reflected a cumulative delay of over a year for each unit from the schedules approved in the seventeenth VCM report, triggered the requirement for the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 to vote to continue construction, and the Co-owners unanimously voted to continue construction.

The Global Amendments provide that Georgia Power may cancel the project at any time at its sole discretion. In the event that Georgia Power determines to cancel the project or fewer than 90% of the Co-owners vote to continue construction upon the occurrence of a subsequent project adverse event, we and the other Co-owners would assess our options for the Vogtle project. If the investment were to be written off, we would seek regulatory accounting treatment to amortize the investment over a long-term period, which requires the approval of our board of directors, and we would submit the regulatory accounting treatment details to the Rural Utilities Service for its approval. Further, if Georgia Power or the Co-owners decided to cancel the project, the Department of Energy would have the discretion to require that we repay all amounts outstanding under our loan guarantee agreement with the Department of Energy over a five-year period as discussed in Note L of Notes to Unaudited Consolidated Financial Statements.

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

See "Item 1A—RISK FACTORS" in our 2022 Form 10-K for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units.

(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 issuances we invest in are rated as investment grade and backed by a credit facility. 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) *Plant Wansley.* In July 2022, the Georgia Public Service Commission approved Georgia Power's 2022 integrated resource plan. This plan requested the decertification of coal-fired Plant Wansley, of which we own a 30% interest, by August 31, 2022. In accordance with the approved plan, Georgia Power retired Plant Wansley in August 2022. Beginning in 2021, we accelerated depreciation of the remaining plant in service assets associated with Plant Wansley based upon the August 2022 retirement date and created a regulatory asset to defer a portion of the accelerated depreciation expense. These deferred costs will be recovered through future rates over a period ending no later than December 31, 2040. The Georgia Public Service Commission also approved Georgia Power's modified closure proposal for the ash pond at Plant Wansley. The proposal recommended closure by removing the ash from the coal ash pond for several site-specific reasons, including available capacity at an existing on-site landfill, the retirement of Plant

Wansley, beneficial use of the coal ash, and managing construction and operational risks of the previous close in place design. The Georgia Environmental Protection Department must also approve the change in closure plans.

(P) *Asset Retirement Obligations.* On March 6, 2023, Plant Vogtle Unit No. 3's nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality. During the first quarter of 2023, we recognized new nuclear asset retirement obligations totaling $62.8 million. During the first quarter of 2023, we also recorded an increase in cash flow estimates of $24.7 million related to existing coal ash related asset retirement obligations. We expect to periodically receive more refined estimates from Georgia Power regarding closure costs and the timing of expenditures.

(Q) *Plant Acquisition.* On May 25, 2023, we acquired one generating unit at the Baconton Power Plant, a four-unit 188 megawatt natural gas-fired combustion turbine facility located near Baconton, Georgia, from Baconton Power, LLC. The unit also features dual-fuel capability and can run on diesel fuel that is stored on site with an aggregate summer planning reserve generation capacity of 47 megawatts.

The purchase price was $16,743,000 and the acquisition also included other transaction costs of approximately $746,000 (consisting primarily of 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. We submitted a loan application to the Rural Utilities Service for long-term financing of this acquisition. 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 Baconton acquisition:

Classification		
		(dollars in thousands)
Recognized identifiable assets acquired and liabilities assumed:		
Electric plant in service, net	**$**	**16,450**
Other current assets		**323**
Other current liabilities		**(30)**
Total identifiable net assets	**$**	**16,743**

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 until on or before January 2026. Prior to the deferring members' use of Baconton, their share of output is being sold into the wholesale market. Revenues and costs of output associated with scheduling members are recognized in the current period. 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 14 years at January 2026. If a deferring member elects to take service before January 2026, amortization of that member's share of the regulatory asset will begin upon taking service.

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 substantially similar wholesale power contracts with each of our members that extend through 2050. We and our members are in preliminary discussions regarding extending the term of the wholesale power contracts for up to an additional 35 years. We are targeting completing this process by year end. For additional information regarding our wholesale power contracts with our members, see “Item 1–BUSINESS–OGLETHORPE POWER CORPORATION–Wholesale Power Contracts” in our 2022 Form 10-K.

Results of Operations

For the Three and Six Months Ended June 30, 2023 and 2022

Net Margin

Our net margin for the three-month and six-month periods ended June 30, 2023 were $18.4 million and $42.8 million, compared to $18.2 million and $40.1 million for the same periods of 2022, respectively. Through June 30, 2023, we collected approximately 65% of our targeted net margin of $66.0 million for the year ending December 31, 2023. 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 2023 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 $4.0 million and $5.0 million as of June 30, 2023 and June 30, 2022, 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 2022 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, 2023 and 2022 were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	(dollars in thousands)			(dollars in thousands)		
	2023	2022	% Change	**2023**	2022	% Change
Capacity revenues	**$234,183**	$ 241,841	(3.2)%	**$476,227**	$485,132	(1.8)%
Energy revenues	**131,313**	236,941	(44.6)%	**276,922**	411,099	(32.6)%
Total	**$365,496**	$ 478,782	(23.7)%	**$753,149**	$896,231	(16.0)%
MWh Sales to members	**6,847,840**	6,235,511	9.8 %	**12,795,892**	11,809,271	8.4 %
Cents/kWh	**5.34**	7.68	(30.5)%	**5.89**	7.59	(22.4)%
Member energy requirements supplied	**71 %**	59 %	20.3 %	**68 %**	58 %	17.2 %

Energy revenues from members decreased for the three-month and six-month periods ended June 30, 2023 compared to the same periods in 2022, primarily due to the recovery of lower fuel costs. The increase in megawatt-hours sold to members for the three-month and six-month periods ended June 30, 2023 compared to the same periods in 2022 partially offset the decrease in fuel costs. For a discussion of fuel costs, which are the primary costs recovered by energy revenues, see "—*Operating Expenses*."

Sales to non-members. Energy revenues from non-members were primarily from the sale of the Bobby C. Smith Jr. Energy Facility's deferring members' output into the wholesale market. In May 2023, our Effingham Energy Facility was renamed the Bobby C. Smith Jr. Energy Facility in honor of our late board chairman. Capacity revenues from non-members related to the two units we acquired at the Washington County Power Plant in December 2022. For additional information regarding the Washington County acquisition, see Note 14 in our 2022 Form 10-K.

Sales to non-members during the three-month and six-month periods ended June 30, 2023 and 2022 were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	(dollars in thousands)			(dollars in thousands)		
	2023	2022	% Change	**2023**	2022	% Change
Energy revenues	**$ 20,269**	$ 54,346	(62.7)%	**$ 21,306**	$ 57,339	(62.8)%
Capacity revenues	**3,624**	—	—	**4,387**	—	—
Total	**$ 23,893**	$ 54,346	(56.0)%	**$ 25,693**	$ 57,339	(55.2)%
MWh Sales to non-members	**686,073**	685,928	— %	**725,288**	755,196	(4.0)%
Cents/kWh	**3.48**	7.92	(56.1)%	**3.54**	7.59	(53.4)%

Energy revenues from non-members decreased for the three-month and six-month periods ended June 30, 2023 compared to the same periods in 2022 primarily due to lower prices and a decrease in megawatt-hours sold to non-members.

Operating Expenses

Fuel

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

	Cost			Generation			Cents per kWh		
	(dollars in thousands)			(MWh)					
	Three Months Ended June 30,			Three Months Ended June 30,			Three Months Ended June 30,		
Fuel Source	**2023**	2022	% Change	**2023**	2022	% Change	**2023**	2022	% Change
Coal	**$ 27,055**	$ 20,486	32.1%	**707,866**	465,140	52.2%	**3.82**	4.40	(13.2)%
Nuclear	**18,353**	18,575	(1.2)%	**2,618,379**	2,575,226	1.7%	**0.70**	0.72	(2.8)%
Gas:									
Combined Cycle	**70,703**	182,532	(61.3)%	**3,700,110**	3,522,740	5.0%	**1.91**	5.18	(63.1)%
Combustion Turbine	**16,357**	41,528	(60.6)%	**502,256**	537,248	(6.5)%	**3.26**	7.73	(57.8)%
	$ 132,468	$ 263,121	(49.7)%	**7,528,611**	7,100,354	6.0%	**1.76**	3.71	(52.6)%

	Cost			Generation			Cents per kWh		
	(dollars in thousands)			(MWh)					
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,		
Fuel Source	**2023**	2022	% Change	**2023**	2022	% Change	**2023**	2022	% Change
Coal	**$ 49,843**	$ 52,773	(5.6)%	**1,286,208**	1,441,462	(10.8)%	**3.88**	3.66	6.0%
Nuclear	**34,395**	35,186	(2.2)%	**4,828,648**	4,824,290	0.1%	**0.71**	0.73	(2.7)%
Gas:									
Combined Cycle	**162,389**	297,589	(45.4)%	**7,026,532**	6,072,321	15.7%	**2.31**	4.90	(52.9)%
Combustion Turbine	**19,009**	43,057	(55.9)%	**579,915**	560,570	3.5%	**3.28**	7.68	(57.3)%
	$ 265,636	$ 428,605	(38.0)%	**13,721,303**	12,898,643	6.4%	**1.94**	3.32	(41.6)%

Total fuel costs decreased for the three-month and six-month periods ended June 30, 2023 compared to the same periods in 2022 as a result of a decrease in the average cost of fuel offset by an increase in generation for members. The decrease in average fuel cost was primarily due to lower average natural gas prices in 2023. The overall increase in generation for the three-month and six-month periods ended June 30, 2023 compared to the same periods in 2022 was largely due to our members obtaining more of their energy requirements from us rather than their third party suppliers due to relative energy prices.

Production

Production costs decreased for the three-month and six-month periods ended June 30, 2023 as compared to the same periods of 2022 primarily as a result of the deferral of net margins associated with Bobby C. Smith Jr.

Interest Charges

Net interest charges increased slightly for the three-month and six-month periods ended June 30, 2023 as compared to the same periods of 2022 as a result of higher interest expense offset by the capitalization of interest expense associated with construction expenditures for Vogtle Units No. 3 and No. 4.

Financial Condition

<u>Balance Sheet Analysis as of June 30, 2023</u>

Assets

Cash used for property additions for the six-month period ended June 30, 2023 totaled $511.9 million. Of this amount, $385.8 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, $38.3 million was for nuclear fuel purchases and $16.7 million for the acquisition of one unit at the Baconton Power Plant. The remainder was for expenditures related to normal additions and replacements to our existing generation facilities. For additional information regarding the Baconton acquisition, see Note Q of Notes to Unaudited Consolidated Financial Statements.

The $57.6 million increase in nuclear decommissioning trust fund was primarily due to the increase in the fair market value of investments due to the recovery in the stock market during the six-month period ended June 30, 2023.

Long-term investments decreased $11.7 million for the six-month period ended June 30, 2023 primarily due to $28.4 million of investments reclassified to short-term investments largely offset by an $18.8 million increase in fair market value of long-term investments.

Restricted cash and investments consists of collateral posted by our counterparties under our natural gas swap agreements and funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. During the six-month period ended June 30, 2023, restricted cash and investments decreased $98.8 million as we fully utilized our remaining $74.0 million of restricted investments for scheduled Rural Utilities Service-guaranteed Federal Financing Bank debt service payments and as a result of a $24.8 million decrease in restricted cash posted by counterparties under our natural gas swap agreements. For additional information regarding restricted cash and investments, see Note I of Notes to Unaudited Consolidated Financial Statements.

Receivables decreased $40.2 million for the six-month period ended June 30, 2023 primarily due to a $44.9 million decrease in member receivables and an $11.2 million decrease in other receivables, including trade receivables related to non-member sales. Offsetting these decreases was an increase of $10.8 million in receivables from Georgia Power.

Prepayments and other current assets decreased $19.7 million during the six-month period ended June 30, 2023 primarily due to a $25.6 million decrease in fair value of our natural gas contracts that will settle within the next twelve months.

Other deferred charges decreased $62.2 million during the six-month period ended June 30, 2023 primarily due to a $55.0 million decrease in fair value of our natural gas contracts that will settle after the next twelve months.

Equity and Liabilities

Long-term debt and long-term debt and finance leases due within one year decreased $168.8 million primarily as a result of $209.9 million in debt service payments. Offsetting this decrease was $38.4 million in advances under a Rural Utilities Service-guaranteed loan. 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, increased $409.2 million during the six-month period ended June 30, 2023. During this period, total short-term borrowings were $484.3 million and repayments totaled $75.1 million.

Accounts payable decreased $74.5 million during the six-month period ended June 30, 2023. The decrease was primarily due to a $48.4 million decrease in payables for natural gas purchases and related transportation and applying $28.5 million in credits to our members' bills in the first quarter of 2023 for a board-approved reduction in 2022 revenue in excess of the requirement to meet the 2022 targeted net margin.

Other current liabilities decreased $70.6 million for the six-month period ended June 30, 2023 primarily as a result of a $24.8 million decrease in restricted cash posted by and due to counterparties under our natural gas swap agreements, a $24.4 million decrease in operating and maintenance liabilities and a $19.9 million decrease in accrued property taxes.

Asset retirement obligations increased $114.5 million for the six-month period ended June 30, 2023 primarily due to recognized nuclear asset retirement obligations of $62.8 million, change in cash flow estimates of $24.7 million for coal ash related decommissioning costs and $32.2 million in accretion expense.

Regulatory liabilities decreased $72.8 million for the six-month period ended June 30, 2023 primarily due to $82.6 million decrease in the liability associated with unrealized gains on our natural gas contracts and a $26.5 million decrease in the liability associated with the deferral of one of our rate management programs. Offsetting such decreases was a $19.8 million increase in collections for future major maintenance outages and a $19.5 million increase associated with deferred nuclear asset retirement obligations that was primarily driven by an increase in unrealized gains associated with our nuclear decommissioning investments. See Note F of Notes to Unaudited Consolidated Financial Statements for a discussion of our member rate management programs.

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 under construction 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, contract management, construction and pre-operation services.

In 2008, Georgia Power, acting for itself and as agent for the Co-owners, entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement) with Westinghouse Electric Company LLC and Stone & Webster, Inc., which was subsequently acquired by Westinghouse and changed its name to WECTEC Global Project Services Inc. (collectively, Westinghouse). Pursuant to the EPC Agreement, Westinghouse agreed to design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle.

Until March 2017, construction on Units No. 3 and No. 4 continued under the substantially fixed price EPC Agreement. In March 2017, Westinghouse filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Effective in July 2017, Georgia Power, acting for itself and as agent for the other Co-owners, and Westinghouse entered into a services agreement (the Services Agreement), pursuant to which Westinghouse is providing facility design and engineering services, procurement and technical support and staff augmentation on a time and materials cost basis. The Services Agreement provides that it will continue until the start-up and testing of Vogtle Units No. 3 and No. 4 is complete and electricity is generated and sold from both units. The Services Agreement is terminable by the Co-owners upon 30 days' written notice.

In October 2017, Georgia Power, acting for itself and as agent for the other Co-owners, entered into a construction completion agreement with Bechtel Power Corporation, pursuant to which Bechtel serves as the primary contractor for the remaining construction activities for Vogtle Units No. 3 and No. 4 (the Bechtel Agreement) and is reimbursed for actual costs plus a base fee and an at-risk fee, subject to adjustment based on Bechtel's performance against cost and schedule targets. Each Co-owner is severally, and not jointly, liable for its proportionate share, based on its ownership interest, of all amounts owed to Bechtel under the Bechtel Agreement. The Co-owners may terminate the Bechtel Agreement at any time for their convenience, provided that the Co-owners will be required to pay amounts related to work performed prior to the termination (including the applicable portion of the base fee), certain termination-related costs and, at certain stages of the work, the applicable portion of the at-risk fee. Bechtel may terminate the Bechtel Agreement under certain circumstances, including certain Co-owner suspensions of work, certain breaches of the Bechtel Agreement by the Co-owners, Co-owner insolvency and certain other events.

Cost and Schedule

Our current budget for our ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs and allowance for funds used during construction, is $8.115 billion and is based on commercial operation dates of July 2023 and March 2024 for Units No. 3 and No. 4, respectively. This budget reflects our June 17, 2022 exercise of the tender option in the Global Amendments to the Joint Ownership Agreements as described below. Had we not exercised the tender option, our budget would be approximately $8.67 billion. At June 30, 2023, our total capital and financing costs for our interest in the additional Vogtle units was $8.4 billion, approximately $300 million of which relates to costs that exceed the tender option threshold that is the subject of litigation between us and Georgia Power, as described below.

The table below shows our project budget and actual costs through June 30, 2023 for our share of the project.

	(in millions)	
	Project Budget	Actual Costs at June 30, 2023
Construction Costs [1]	$ 6,559	$ 6,393
Freeze Capital Credit [2]	(532)	—
Financing Costs	2,038	1,925
Subtotal	$ 8,065	$ 8,318 [3]
Deferred Training Costs	47	47
Total Project Costs before Contingency	$ 8,112	$ 8,365
Oglethorpe Contingency	$ 3	$ —
Totals	$ 8,115	$ 8,365

[1] Construction costs are net of $1.1 billion we received from Toshiba Corporation under a Guarantee Settlement Agreement and $99 million in cost sharing benefits associated with the Global Amendments to the Joint Ownership Agreements.

[2] As described below, we exercised the tender option to cap our capital costs at the EAC in VCM 19 plus $2.1 billion, the freeze tender threshold. The freeze capital credit reflects our share of budgeted amounts that exceed this threshold.

[3] At June 30, 2023, approximately $300 million relates to costs that exceed the tender option threshold that is the subject of litigation between us and Georgia Power.

Any schedule extension beyond March 2024 for Unit No. 4 is expected to increase our financing costs by approximately $10-$15 million per month for Unit No. 4. We and some of our members have implemented various rate management programs to lessen the impact on rates related to the additional Vogtle units.

Our initial ownership interest and proportionate share of the cost to construct the additional Vogtle units was 30%, representing approximately 660 megawatts. However, we have exercised the tender option discussed below which caps our capital costs in exchange for a proportionate reduction of our 30% interest in the two units. Based on the current project budget and schedule and our interpretation of the Global Amendments (described below), we would transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share would decline from 30% to approximately 27.5%. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced.

On March 6, 2023, the Unit No. 3 nuclear reactor achieved self-sustaining nuclear fission, commonly referred to as initial criticality, and, on April 1, 2023, the generator successfully synchronized to the power grid and generated electricity for the first time. Georgia Power placed Unit No. 3 in service on July 31, 2023.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts for Unit No. 4 on a regular basis to incorporate current information available, particularly in the areas of start-up testing and related test results, engineering support, commodity installations, system turnovers and workforce statistics.

Since March 2020, the number of active cases of COVID-19 at the site has fluctuated consistent with the surrounding area and impacted productivity levels and pace of activity completion. As of June 30, 2023, the incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity, substantially all of which occurred during 2020 and 2021, is estimated by Georgia Power to be approximately $440 million, or approximately $130 million based on our initial 30% share, and is included in the project budget.

On May 1, 2023, hot functional testing was completed at Unit No. 4. On July 20, 2023, Southern Nuclear announced that all Unit No. 4 inspections, tests, analyses, and acceptance criteria documentation had been submitted to the Nuclear Regulatory Commission, and, on July 28, 2023, the Nuclear Regulatory Commission published its 103(g) finding that the accepted criteria in the combined license for Unit No. 4 had been met, which allows nuclear fuel to be loaded and start-up testing to begin. Georgia Power has disclosed that it projects an in-service date for Unit No. 4 during late fourth quarter 2023 or during the first quarter 2024. Given the remaining work to be done and potential risks associated with completing the work, our current budget anticipates an in-service date for Unit No. 4 in March 2024. Meeting the projected in-service date for Unit No. 4 significantly depends on maintaining overall construction productivity and production levels, particularly in completing remaining subcontractor scopes of work while reducing the level of craft laborers based on work remaining. As Unit No. 4 completes construction and transitions further into testing, ongoing and potential future challenges include the pace and quality of remaining commodities installations; the management of contractors and vendors, subcontractor performance, the availability of materials and parts, and/or related cost escalation; the pace of remaining work package closures; and the availability of craft, supervisory and technical support resources; and the timeframe and duration of final component and pre-operational testing.

New challenges also may continue to arise as Unit No. 4 moves further into testing and start-up, which may result in required engineering changes or remediation related to plant systems, structures or components (some of which are based on new technology that only within the last few years began initial operation in the global nuclear industry at this scale). These challenges may result in further schedule delays and/or cost increases.

There have been technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4 at the federal and state level and additional challenges may arise. Processes are in place that are designed to ensure compliance with the requirements specified in the Westinghouse Design Control Document and the combined construction and operating licenses, including inspections by Southern Nuclear and the Nuclear Regulatory Commission that occur throughout construction.

With the receipt of the Nuclear Regulatory Commission's 103(g) findings for Units No. 3 and No. 4 in August 2022 and July 2023, respectively, the site is subject to the Nuclear Regulatory Commission's operating reactor oversight process and must meet applicable technical and operational requirements contained in its operating license. Various design and other licensing-based compliance matters may result in additional license amendment requests or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

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

Co-Owner Contracts and Other Information

In November 2017, the Co-owners entered into an amendment to their joint ownership agreements for Vogtle Units No. 3 and No. 4 to provide for, among other conditions, additional Co-owner approval requirements. These joint ownership agreements, including the Co-owner approval requirements, were subsequently amended, effective August 31, 2018. As described below, certain provisions of the Joint Ownership Agreements were modified further on September 26, 2018 by the Term Sheet that was memorialized on February 18, 2019 when the Co-owners entered into certain amendments (the Global Amendments) to the Joint Ownership Agreements (as amended, the Joint Ownership Agreements).

As a result of an increase in the total project capital cost forecast and Georgia Power's decision not to seek recovery of its allocation of the increase in the base capital costs and the increased construction budget in connection with Georgia Power's nineteenth Vogtle construction monitoring report (VCM 19) in 2018, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 were required to vote to continue construction. In September 2018, the Co-owners unanimously voted to continue construction of Vogtle Units No. 3 and No. 4.

In connection with the September 2018 vote to continue construction, Georgia Power entered into a binding term sheet with the other Co-owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, and MEAG Power SPVP, LLC to mitigate certain financial exposure for the other Co-owners and offered to purchase production tax credits from each of the other Co-Owners, at that Co-owner's option (the Term Sheet). On February 18, 2019, the Co-owners entered into the Global Amendments to memorialize the provisions of the Term Sheet. Pursuant to the Global Amendments and consistent with the Term Sheet, the Joint Ownership Agreements provide that:

- each Co-owner is obligated to pay its proportionate share of construction costs for Vogtle Units No. 3 and No. 4 based on its ownership interest up to (i) the estimated cost at completion ("EAC") for Vogtle Units No. 3 and No. 4 which formed the basis of Georgia Power's forecast of $8.4 billion in Georgia Power's VCM 19 filed with the Georgia Public Service Commission plus (ii) $800 million of additional construction costs.

- Georgia Power will be responsible for 55.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $800 million to $1.6 billion (resulting in up to $80 million of potential additional costs to Georgia Power which would save Oglethorpe up to $44 million), with the remaining Co-owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests (equal to 24.5% for our 30% ownership interest); and

- Georgia Power will be responsible for 65.7% of construction costs, subject to exceptions such as costs that are a result of a force majeure event, that exceed the EAC in VCM 19 by $1.6 billion to $2.1 billion (resulting in up to a further $100 million of potential additional costs to Georgia Power which would save Oglethorpe up to an additional $55 million), with the remaining Co-owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests (equal to 19.0% for our 30% ownership interest).

If the EAC is revised and exceeds the EAC in VCM 19 by more than $2.1 billion, each of the Co-owners, other than Georgia Power, has a one-time option to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Co-owner's share of construction costs actually incurred in excess of the EAC in VCM 19 plus $2.1 billion. If any Co-owner elects to exercise this tender option, Georgia Power would have the option to cancel the project in lieu of accepting the offer to purchase a portion of the Co-owner's ownership interest. If Georgia Power does not elect to cancel the project, then Georgia Power must accept the offer, and the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the percentage of the cumulative amount of construction costs paid by such tendering Co-owner as of the commercial operation date of Vogtle Unit No. 4. For purposes of this calculation, payments made by Georgia Power on behalf of the tendering Co-owner in accordance with the second and third bullets above will be treated as payments made by that Co-owner. This option to tender a portion of our interest to Georgia Power upon such a budget increase allowed us to freeze our construction budget associated with the Vogtle project in exchange for a proportionate reduction of our 30% ownership interest.

The VCM 19 total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. As of December 31, 2021, budget increases since VCM 19 reached $3.4 billion for all Co-owners. As a result of those increases, we believe that the tender option was triggered at the Co-owner construction budget vote on February 14, 2022 and that Georgia Power's increased responsibility for certain construction costs as described above commenced in March 2022.

On June 17, 2022, we notified Georgia Power of our election to exercise the tender option and cap our capital costs in exchange for a proportionate reduction of our 30% interest in the two new units. Our decremental ownership interest will be calculated and conveyed to Georgia Power after both Vogtle units are placed in service. Based on the current project budget, our schedule assumptions and our interpretation of the Global Amendments, our project budget is $8.1 billion and we expect to transfer approximately 55 megawatts, out of 660 megawatts, to Georgia Power. Our resulting ownership share will decline from 30% to approximately 27.5%. By exercising the tender option and based on current assumptions, we estimate that we will avoid incurring approximately $535 million in construction costs associated with the project. However, if the total project costs exceed the current budget, our ownership share and megawatts would be further reduced. On July 26, 2022, the City of Dalton notified Georgia Power that it had elected to exercise its tender option.

We and Georgia Power do not agree on certain aspects of the tender option, including the dollar amount that triggers our option to tender a portion of our ownership interest to Georgia Power under the tender option or the extent to which costs that are the result of a force majeure event (such as COVID-19) impact the point at which the tender option is triggered. For purposes of determining when our option to tender was triggered, the Global Amendments do not exclude costs resulting from force majeure events (such as COVID-19) from the calculation of when the EAC in VCM 19 plus $2.1 billion has been reached. We and Georgia Power also do not agree on the dollar amount that triggered Georgia Power's increased responsibility for certain construction costs as described above, and the extent to which costs that are the result of a force majeure event (such as COVID-19), impact the calculation of the point at which Georgia Power's increased responsibility for certain construction costs as described above was triggered. The exclusion of costs resulting from a force majeure event (such as COVID-19) in the Global Amendments only applies to Georgia Power's increased cost responsibility during the time period when construction costs exceed the EAC in VCM 19 by $800 million to $2.1 billion.

Accordingly, in March 2022, we notified Georgia Power of a billing dispute with regards to both the starting dollar amount and the application of costs resulting from a force majeure event and how such amounts impact the thresholds and timing of the cost-sharing and tender option provisions. On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County, Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim against us seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power's related financial obligations. Based on the current project budget and Georgia Power's interpretation of the Global Amendments, our project budget would be $8.67 billion, and we would incur approximately $535 million of additional construction costs (excluding related financing costs) and retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

Pursuant to the Joint Ownership Agreements, as amended by the Global Amendments, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Global Amendment provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more from the seventeenth VCM report estimated in-service dates of November 2021 and November 2022 for Units No. 3 and No. 4, respectively. The schedule extensions, announced in February 2022, which reflected a cumulative delay of over a year for each unit from the schedules approved in the seventeenth VCM report, triggered the requirement for the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 to vote to continue construction, and the Co-owners unanimously voted to continue construction.

The Global Amendments provide that Georgia Power may cancel the project at any time at its sole discretion. In the event that Georgia Power determines to cancel the project or fewer than 90% of the Co-owners vote to continue construction upon the occurrence of a subsequent project adverse event, we and the other Co-owners would assess our options for the Vogtle project. If the investment were to be written off, we would seek regulatory accounting treatment to amortize the investment over a long-term period, which requires the approval of our board of directors, and we would submit the regulatory accounting treatment details to the Rural Utilities Service for its approval. Further, if Georgia Power or the Co-owners decided to cancel the project, the Department of Energy would have the discretion to require that we repay all amounts outstanding under our loan guarantee agreement with the Department of Energy over a five-year period as discussed in Note L of Notes to Unaudited Consolidated Financial Statements.

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

See “Item 1A—RISK FACTORS” in our 2022 Form 10-K for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units.

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 2022 Form 10-K.

On May 23, 2023, the Environmental Protection Agency published proposed rules to replace the Affordable Clean Energy rule that would limit greenhouse gas emissions from new, modified, reconstructed, and existing fossil-fuel power plants. If finalized as proposed, the rules would likely adversely impact a portion of our coal and natural gas-fired generating units and have a significant impact on the U.S. power sector overall. We are reviewing EPA's proposed rules to better understand the potential impact on our operations. The ultimate impact of the proposed rules will depend on the final rules adopted by EPA and the results of any litigation challenging the rules and cannot be determined at this time.

In addition, EPA proposed three other rules that will affect power plants earlier in 2023. The first, published on January 27, 2023, would tighten the National Ambient Air Quality Standards (NAAQS) for fine particulate matter (PM2.5) from emissions sources. The second, published on March 29, 2023, would revise effluent limitation guidelines (ELG) for wastewater streams at coal-fired power plants and the third, published on April 24, 2023, would revise the Mercury and Air Toxics Standards (MATS) for coal-fired power plants. We are reviewing the proposed rules, however, their ultimate impact cannot be determined at this time.

Liquidity

At June 30, 2023, we had $1.2 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $459 million in cash and cash equivalents, and $737 million available under our $1.8 billion of committed credit arrangements, the details of which are reflected in the table below:

Committed Credit Facilities				
	Authorized Amount	Available June 30, 2023		Expiration Date
	(dollars in millions)			
Unsecured Facilities:				
Syndicated Line among 12 banks led by CFC	$ 1,210	$ 140	(1)	December 2024
CFC Line of Credit(2)	110	110		December 2023
JPMorgan Chase Line of Credit	350	347	(3)	October 2024
Secured Facilities:				
CFC Term Loan(2)	250	140		December 2023

(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, 2023.

(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, 2023, $2.5 million of this facility was used for letters of credit issued to provide performance assurance to third parties.

We have the flexibility to use the $1.2 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 $1.2 billion syndicated line of credit. Currently, we are issuing commercial paper primarily to provide interim funding for:

- payments related to the construction of Vogtle Units No. 3 and No. 4,
- principal payments due under our Department of Energy-guaranteed loans, which began in February 2020, and
- costs related to the Washington County and Baconton 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 remaining construction costs for Vogtle Units No. 3 and No. 4, refinancing of the principal payments we are currently paying under our Department of Energy-guaranteed loans, 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 County and Baconton acquisitions. For additional information regarding the Washington County acquisition, see Note 14 in our 2022 Form 10-K. For additional information regarding the Baconton acquisition, see Note Q of Notes to Unaudited Consolidated Financial Statements.

At June 30, 2023, our unsecured committed lines of credit provided us the capacity to issue letters of credit totaling up to $960 million in the aggregate and $597.0 million remained available for the issuance of letters of credit under these lines of credit.

Between projected cash on hand and the credit arrangements currently in place, we believe we have sufficient liquidity to cover normal operations and our interim financing needs, including interim financing for the new Vogtle units, Department of Energy principal payments, and the Washington County and Baconton acquisitions, until long-term financing is obtained.

Three of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At June 30, 2023, the required minimum level was $750 million and our actual patronage capital was $1.2 billion. These agreements contain an additional covenant that limits our secured indebtedness and unsecured indebtedness, both as defined in the credit agreements, to $14 billion and $4 billion, respectively. At June 30, 2023, we had $11.8 billion of secured indebtedness and $1.1 billion 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, 2023, we had seven members participating in the program and a balance of $95.3 million remaining to be applied against future power bills.

At June 30, 2023, we had $5.6 million of cash collateral posted by counterparties to our natural gas hedge program, all of which is classified as restricted cash.

Financing Activities

First Mortgage Indenture. At June 30, 2023, we had $11.8 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 2022 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. At June 30, 2023, we had one approved Rural Utilities Service-guaranteed loan totaling $630.3 million to fund general and environmental improvements that had $226.3 million remaining to be advanced. When advanced, the debt will be secured ratably under our first mortgage indenture. As of June 30, 2023, we had $2.7 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. We have fully advanced the $4.6 billion available under the Department of Energy-guaranteed loans and $4.2 billion was outstanding at June 30, 2023. 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, 2023, we had repaid $393.6 million under these loans and expect to repay a total of approximately $486 million in principal on these loans by March 2024. We plan to issue first mortgage bonds to refinance the principal repaid after the in-service date of Vogtle Unit No. 4.

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 2022 Form 10-K.

Bond Financings. On February 1, 2023, we remarketed $99.8 million of Series 2017 pollution control revenue bonds. The remarketed bonds bear interest at indexed put rate modes until February 1, 2028 and are scheduled to mature in 2045. Our payment obligations related to these bonds are secured under our first mortgage indenture. In the fourth quarter of 2023, we plan to issue $500 million of taxable first mortgage bonds to provide long-term financing or refinancing of expenditures related to Vogtle Units No. 3 and No. 4.

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 2022 Form 10-K.

Item 4. Controls and Procedures

As of June 30, 2023, 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, 2023 that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

On June 18, 2022, after completing the dispute resolution procedures set forth in the Ownership Participation Agreement for the additional Vogtle units, we and MEAG filed separate lawsuits against Georgia Power in the Superior Court of Fulton County Georgia seeking to enforce the terms of the Global Amendments. Our lawsuit seeks declaratory judgment that the cost-sharing and tender provisions of the Global Amendments have been triggered based on a VCM 19 forecast of $17.1 billion. Our lawsuit also alleges breach of contract and asserts other claims and seeks damages and injunctive relief requiring Georgia Power to track and allocate construction costs consistent with our interpretation of the Global Amendments. On July 28, 2022, Georgia Power filed a counterclaim seeking a declaratory judgment that the starting dollar amount is $18.38 billion and that costs related to force majeure events are excluded prior to calculating the cost-sharing and tender provisions and when calculating Georgia Power's related financial obligations. Based on the current project budget and Georgia Power's interpretation of the Global Amendments, our project budget would be $8.67 billion, and we would incur approximately $535 million of additional construction costs (excluding related financing costs) and we would retain substantially all of our 30% interest in the additional units. On September 26, 2022, the City of Dalton filed a complaint in our lawsuit and joined our claims. On September 29, 2022, Georgia Power and MEAG reached an agreement with respect to their pending litigation.

See "Management's Discussion and Analysis of Financial Condition and Results of Operation – Financial Condition – Capital Requirements and Liquidity and Sources of Capital – *Vogtle Units No. 3 and No. 4*" for additional information regarding Vogtle Units No. 3 and No. 4.

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

Legislative and regulatory actions intended to address climate change and to reduce greenhouse gas emissions, including carbon dioxide, may result in significant compliance costs or expenses.

Concerns regarding climate change continue to increase and the responses to those concerns by policymakers, regulators, investors, consumers and other stakeholders may affect us and our members in various ways. The costs associated with legislative or regulatory actions intended to reduce greenhouse gas emissions could be significant.

President Biden has signed a number of executive orders directing federal agencies to address climate change, environmental justice, and other environmental issues. President Biden also recommitted the United States to the Paris Climate Agreement effective February 19, 2021. In April 2021, under the agreement's format, the United States announced a nationally determined contribution for reducing economy-wide carbon dioxide emissions by 50-52% below 2005 levels by 2030. In order to meet the United States nationally determined contribution, analyses indicate that the power sector would have to reduce carbon dioxide emissions by about 80% below 2005 levels by 2030.

On May 23, 2023, EPA published proposed rules to replace the Affordable Clean Energy rule that would limit greenhouse gas emissions from new, modified, reconstructed, and existing fossil-fuel power plants in a manner consistent with the United States' nationally determined contribution. If finalized as proposed, the rules would likely adversely impact a portion of our coal and natural gas-fired generating units and have a significant impact on the U.S. power sector overall. We are reviewing EPA's proposed rules to better understand the potential impact on our operations. The ultimate impact of the proposed rules will depend on the final rules adopted by EPA and the results of any litigation challenging the rules and cannot be determined at this time.

Based on these developments, and trends more generally, we expect federal and state legislative and regulatory efforts to reduce the potential impacts of climate change and limit greenhouse gas emissions, including carbon dioxide, to continue. For example, the Inflation Reduction Act of 2022 includes significant financial incentives to accelerate the U.S. transition to a lower greenhouse gas emitting economy. Congress has also recently considered proposals that would mandate significant emissions reductions or increases in clean energy generation from the power sector. Passing new climate legislation, whether in the form of a carbon tax, a clean electricity standard or another proposal, remains challenging in the near-term. The timing, cost and effect of any proposed or future laws or regulations attempting to address climate change and reduce greenhouse gas emissions are uncertain. If adopted, however, such laws or regulations could impose operational restrictions on affected generating facilities and impose substantial costs on our business.

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

During the fiscal quarter ended June 30, 2023, 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	Eighty-Fifth Supplemental Indenture, dated as of February 6, 2023, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to conforming the lien of the indenture with respect to certain after-acquired property.
4.2	Eighty-Sixth Supplemental Indenture, dated as of May 25, 2023, made by Oglethorpe to U.S. Bank Trust Company, National Association, as trustee, relating to recording the indenture in Mitchell County, Georgia.
10.1	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of May 31, 2023, between Oglethorpe, as borrower, and National Rural Utilities Cooperative Finance Corporation, as administrative agent.
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 2020-2022).
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 10, 2023

By: /s/ Michael L. Smith

Michael L. Smith
President and Chief Executive Officer

Date: August 10, 2023

/s/ Elizabeth B. Higgins

Elizabeth B. Higgins
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)