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 September 30, 2021

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 SEPTEMBER 30, 2021

CAUTIONARY STATEMENT REGARDING

FORWARD-LOOKING STATEMENTS

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, 2020 and in this quarterly report on Form 10-Q. In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this quarterly report may not occur.

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

- cost increases and schedule delays with respect to our capital improvement and construction projects, in particular, the construction of two additional nuclear units at Plant Vogtle;

- the duration and severity of the current coronavirus ("COVID-19") pandemic and resulting economic disruption and its impact on our business, financial condition, operations, construction projects, including the additional units at Plant Vogtle, and our members and their service territories;

- a decision by Georgia Power Company to cancel the additional Vogtle units or a decision by more than 10% of the co-owners of the additional Vogtle units not to proceed with the construction of the additional Vogtle units upon the occurrence of certain material adverse events;

- decisions made by the Georgia Public Service Commission in the regulatory process related to the two additional units at Plant Vogtle;

- 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;

- our ability to receive advances under the U.S. Department of Energy loan guarantee agreement for constructing two additional nuclear units at Plant Vogtle;

- 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;

- 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;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;
- adequate funding of our nuclear decommissioning trust funds including investment performance and projected decommissioning costs;
- early retirement of one or more 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;
- 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, such as influenza, or similar occurrences; and

- other factors discussed elsewhere in this quarterly report or in other reports we file with the SEC.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
September 30, 2021 and December 31, 2020

	(dollars in thousands)	
	2021	2020
Assets		
Electric plant:		
In service	**$ 9,790,913**	$ 9,394,112
Right-of-use assets—finance leases	**302,732**	302,732
Less: Accumulated provision for depreciation	**(5,397,418)**	(4,968,294)
	4,696,227	4,728,550
Nuclear fuel, at amortized cost	**365,685**	358,728
Construction work in progress	**6,534,429**	5,783,579
Total electric plant	**11,596,341**	10,870,857
Investments and funds:		
Nuclear decommissioning trust fund	**635,958**	598,181
Investment in associated companies	**73,099**	74,844
Long-term investments	**678,704**	518,065
Restricted investments	**73,400**	306,601
Other	**30,441**	29,189
Total investments and funds	**1,491,602**	1,526,880
Current assets:		
Cash and cash equivalents	**452,943**	405,511
Restricted short-term investments	**246,580**	180,986
Receivables	**205,128**	152,466
Inventories, at average cost	**237,018**	280,289
Prepayments and other current assets	**94,370**	33,839
Total current assets	**1,236,039**	1,053,091
Deferred charges:		
Regulatory assets	**898,117**	731,438
Prepayments to Georgia Power	**34,859**	37,601
Other	**59,208**	20,289
Total deferred charges	**992,184**	789,328
Total assets	**$ 15,316,166**	$ 14,240,156

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

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
September 30, 2021 and December 31, 2020

	(dollars in thousands)	
	2021	2020
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 1,120,652**	$ 1,072,642
Long-term debt	**10,330,910**	10,298,385
Obligation under finance leases	**65,207**	68,876
Other	**27,402**	26,861
Total capitalization	**11,544,171**	11,466,764
Current liabilities:		
Long-term debt and finance leases due within one year	**263,010**	208,649
Short-term borrowings	**1,023,374**	383,498
Accounts payable	**159,712**	162,249
Accrued interest	**78,276**	72,434
Member power bill prepayments, current	**26,207**	46,068
Other current liabilities	**82,285**	68,932
Total current liabilities	**1,632,864**	941,830
Deferred credits and other liabilities:		
Asset retirement obligations	**1,214,467**	1,135,983
Member power bill prepayments, non-current	**86,492**	98,113
Regulatory liabilities	**816,229**	566,399
Other	**21,943**	31,067
Total deferred credits and other liabilities	**2,139,131**	1,831,562
Total equity and liabilities	**$ 15,316,166**	$ 14,240,156

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 Nine Months Ended September 30, 2021 and 2020

	(dollars in thousands)			
	Three Months		Nine Months	
	2021	2020	**2021**	2020
Operating revenues:				
Sales to members	**$ 437,240**	$ 365,937	**$ 1,171,433**	$ 1,038,218
Sales to non-members	**23,582**	302	**23,847**	639
Total operating revenues	**460,822**	366,239	**1,195,280**	1,038,857
Operating expenses:				
Fuel	**214,681**	131,925	**436,277**	282,677
Production	**99,321**	94,071	**298,171**	303,705
Depreciation and amortization	**69,758**	61,758	**204,654**	186,370
Purchased power	**16,920**	16,419	**50,706**	49,366
Accretion	**14,117**	14,204	**41,839**	40,830
Total operating expenses	**414,797**	318,377	**1,031,647**	862,948
Operating margin	**46,025**	47,862	**163,633**	175,909
Other income:				
Investment income	**12,299**	11,672	**36,389**	36,210
Other	**2,516**	1,832	**4,964**	5,733
Total other income	**14,815**	13,504	**41,353**	41,943
Interest charges:				
Interest expense	**105,201**	101,600	**312,927**	305,128
Allowance for debt funds used during construction	**(56,179)**	(51,518)	**(164,628)**	(153,595)
Amortization of debt discount and expense	**2,911**	2,813	**8,677**	8,482
Net interest charges	**51,933**	52,895	**156,976**	160,015
Net margin	**$ 8,907**	$ 8,471	**$ 48,010**	$ 57,837

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 Nine Months Ended September 30, 2021 and 2020

		(dollars in thousands)
Balance at December 31, 2019	$	1,016,747
Net margin		23,204
Balance at March 31, 2020	$	1,039,951
Net margin		26,162
Balance at June 30, 2020	$	1,066,113
Net margin		8,471
Balance at September 30, 2020	$	1,074,584
Balance at December 31, 2020	$	1,072,642
Net margin		25,958
Balance at March 31, 2021	$	1,098,600
Net margin		13,145
Balance at June 30, 2021	$	1,111,745
Net margin		8,907
Balance at September 30, 2021	**$**	**1,120,652**

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

Oglethorpe Power Corporation
Consolidated Statements of Cash Flows (Unaudited)
For the Nine Months Ended September 30, 2021 and 2020

	(dollars in thousands)	
	2021	2020
Cash flows from operating activities:		
Net margin	**$ 48,010**	$ 57,837
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**297,976**	278,872
Accretion cost	**41,839**	40,830
Amortization of deferred gains	**(1,341)**	(1,341)
Allowance for equity funds used during construction	**(267)**	(306)
Deferred outage costs	**(27,163)**	(36,502)
Gain on sale of investments	**(11,665)**	(14,122)
Regulatory deferral of costs associated with nuclear decommissioning	**(15,592)**	(11,482)
Other	**(639)**	(2,566)
Change in operating assets and liabilities:		
Receivables	**(51,283)**	(22,751)
Inventories	**46,686**	3,836
Prepayments and other current assets	**(6,199)**	(30,914)
Accounts payable	**(4,487)**	(28,764)
Accrued interest	**5,842**	10,483
Accrued taxes	**6,788**	35,004
Other current liabilities	**522**	(16,433)
Member power bill prepayments	**(31,482)**	(56,975)
Rate management program collections	**117,600**	114,006
Total adjustments	**367,135**	260,875
Net cash provided by operating activities	**415,145**	318,712
Cash flows from investing activities:		
Property additions	**(891,162)**	(983,902)
Plant acquisition	**(233,156)**	—
Activity in nuclear decommissioning trust fund—Purchases	**(556,879)**	(393,369)
—Proceeds	**550,956**	387,277
Decrease (increase) in restricted investments	**167,607**	(7,282)
Activity in other long-term investments—Purchases	**(340,877)**	(285,842)
—Proceeds	**184,083**	136,476
Other	**8,139**	9,075
Net cash used in investing activities	**(1,111,289)**	(1,137,567)
Cash flows from financing activities:		
Long-term debt proceeds	**517,524**	2,045,685
Long-term debt payments	**(440,548)**	(1,274,196)
Increase (decrease) in short-term borrowings, net	**639,876**	(16,255)
Other	**30,124**	(1,123)
Net cash provided by financing activities	**746,976**	754,111
Net increase (decrease) in cash, cash equivalents and restricted cash	**50,832**	(64,744)
Cash, cash equivalents and restricted cash at beginning of period	**405,511**	448,612
Cash, cash equivalents and restricted at end of period	**$ 456,343**	$ 383,868
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 141,206**	$ 139,878
Supplemental disclosure of non-cash investing and financing activities:		
Change in asset retirement obligations	**$ 42,964**	$ 22,086
Accrued property additions at end of period	**$ 71,443**	$ 94,365

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 nine-month periods ended September 30, 2021 and 2020. 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) revenue recognition, such as determining the nature and timing of satisfaction of performance obligations, determining the standalone selling price of performance obligations and variable consideration. 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, 2020, as filed with the SEC. The results of operations for the three- and nine-month periods ended September 30, 2021 are not necessarily indicative of results to be expected for the full year. As noted in our 2020 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 2020 Form 10-K.

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

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

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

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

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

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

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

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

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

The tables below detail assets and liabilities measured at fair value on a recurring basis at September 30, 2021 and December 31, 2020.

		Fair Value Measurements at Reporting Date Using		
	September 30, 2021	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	**$ 225,255**	$ 225,255	$ —	$ —
International equity trust	**142,018**	—	142,018	—
Corporate bonds and debt	**78,874**	—	78,306	568
US Treasury securities	**54,212**	54,212	—	—
Mortgage backed securities	**33,712**	—	33,712	—
Domestic mutual funds	**74,861**	74,861	—	—
Municipal bonds	**1,130**	—	1,130	—
Federal agency securities	**9,792**	—	9,792	—
Non-US Gov't bonds & private placements	**2,696**	—	2,696	—
Other	**13,408**	13,408	—	—
Long-term investments:				
International equity trust	**35,015**	—	35,015	—
Corporate bonds and debt	**15,590**	—	15,272	318
US Treasury securities	**13,440**	13,440	—	—
Mortgage backed securities	**11,582**	—	11,582	—
Domestic mutual funds	**271,354**	271,354	—	—
Federal agency securities	**290**	—	290	—
Treasury STRIPS	**325,398**	—	325,398	—
Other	**6,035**	6,035	—	—
Natural gas swaps	**93,930**	—	93,930	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2020	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	$ 198,325	$ 198,325	$ —	$ —
International equity trust	120,645	—	120,645	—
Corporate bonds and debt	98,129	—	97,788	341
US Treasury securities	46,963	46,963	—	—
Mortgage backed securities	45,039	—	45,039	—
Domestic mutual funds	70,813	70,813	—	—
Municipal bonds	1,362	—	1,362	—
Federal agency securities	6,054	—	6,054	—
Other	10,851	7,720	3,131	—
Long-term investments:				
International equity trust	31,378	—	31,378	—
Corporate bonds and debt	29,870	—	29,661	209
US Treasury securities	7,437	7,437	—	—
Mortgage backed securities	11,432	—	11,432	—
Domestic mutual funds	224,536	224,536	—	—
Federal agency securities	537	—	537	—
Treasury STRIPS	209,165	—	209,165	—
Other	3,710	3,710	—	—
Natural gas swaps	10,248	—	10,248	—

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 September 30, 2021 and December 31, 2020 were as follows:

	2021		2020	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
	(in thousands)			
Long-term debt	**$ 10,700,098**	**$ 12,568,831**	$ 10,619,826	$ 13,161,146

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 September 30, 2021 and December 31, 2020 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 trading 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 derivative 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 September 30, 2021, all of the counterparties with transaction amounts outstanding under our hedging 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 contract 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 September 30, 2021 and December 31, 2020, the estimated fair values of our natural gas contracts were net assets of approximately $93,930,000 and net liabilities of approximately $10,248,000, respectively.

At September 30, 2021, one of our counterparties was required to post credit collateral totaling $3,400,000 under our natural gas swap agreements. At December 31, 2020, none of our counterparties were required to post credit collateral. Such collateral is classified as restricted cash and included in the Prepayments and other current assets line item within our unaudited consolidated balance sheets.

The following table reflects the notional volume of our natural gas derivatives at September 30, 2021 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2021	4.4
2022	24.2
2023	23.8
2024	23.2
2025	19.9
2026	12.9
Total	**108.4**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at September 30, 2021 and December 31, 2020.

	Balance Sheet Location	Fair Value	
		2021	2020
		(dollars in thousands)	
Assets:			
Natural gas swaps	Other current assets	**$ 47,303**	$ 222
Natural gas swaps	Other deferred charges	**$ 46,627**	$ —
Liabilities:			
Natural gas swaps	Other current liabilities	**$ —**	$ 2,305
Natural gas swaps	Other deferred credits	**$ —**	$ 8,165

The following table presents the gross realized gains and (losses) on derivative instruments recognized in net margins for the three and nine months ended September 30, 2021 and 2020.

	Statement of Revenues and Expenses Location	Three Months Ended September 30,		Nine Months Ended September 30,	
		2021	2020	**2021**	2020
		(dollars in thousands)			
Natural gas swaps gains	Fuel	**$ 15,831**	$ 339	**$ 18,229**	$ 339
Natural gas swaps losses	Fuel	**—**	(8,721)	**(1,311)**	(20,314)
Total		**$ 15,831**	$ (8,382)	**$ 16,918**	$ (19,975)

The following table presents the unrealized gains and losses on derivative instruments deferred on the balance sheet at September 30, 2021 and December 31, 2020.

	Balance Sheet Location	2021	2020
		(dollars in thousands)	
Natural gas swaps	Regulatory asset	**$ —**	$ 10,248
	Regulatory liability	**93,930**	—
Total		**$ 93,930**	$ 10,248

(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 at September 30, 2021 and December 31, 2020.

		Gross Unrealized (dollars in thousands)		
September 30, 2021	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$ 300,141**	**$ 253,423**	**$ (4,727)**	**$ 548,837**
Debt	**743,582**	**6,727**	**(3,928)**	**746,381**
Other	**19,444**	**—**	**—**	**19,444**
Total	**$ 1,063,167**	**$ 260,150**	**$ (8,655)**	**$ 1,314,662**

		Gross Unrealized (dollars in thousands)		
December 31, 2020	Cost	Gains	Losses	Fair Value
Equity	$ 262,564	$ 219,658	$ (8,127)	$ 474,095
Debt	613,271	18,090	(641)	630,720
Other	11,431	—	—	11,431
Total	$ 887,266	$ 237,748	$ (8,768)	$ 1,116,246

(E) *Recently Issued or Adopted Accounting Pronouncements.* In March 2020, the Financial Accounting Standards Board (FASB) issued “Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting”. The amendments in this update apply to all entities that have contracts, hedging relationships, and other transactions that reference London Interbank Offered Rate (LIBOR) or another reference rate expected to be discontinued because of reference rate reform. The amendments in this update provide optional expedients and exceptions for applying U.S. GAAP to transactions affected by reference rate reform if certain criteria are met. The expedients and exceptions provided by the amendments in this update do not apply to contract modifications made and hedging relationships entered into or evaluated after December 31, 2022, except for hedging relationships existing as of December 31, 2022, for which an entity has elected certain optional expedients that are retained through the end of the hedging relationship.

In January 2021, the FASB issued “Reference Rate Reform (Topic 848): Scope,” to further clarify the scope of the reference rate reform guidance in Topic 848. The amendments in this update refine the scope of Topic 848 to clarify that certain optional expedients and exceptions therein for contract modifications and hedge accounting apply to contracts that are affected by the discounting transition. Specifically, modifications related to reference rate reform would not be considered an event that requires reassessment of previous accounting conclusions. The amendments in this update also amend the expedients and exceptions in Topic 848 to capture the incremental consequences of the scope clarification and to tailor the existing guidance to derivative instruments affected by the discounting transition.

The amendments in these updates are effective for all entities as of March 12, 2020 through December 31, 2022. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In December 2019, the FASB issued “Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes”, as part of its initiative to reduce complexity in the accounting standards. The amendments in the standard remove certain exceptions and also clarify and simplify various aspects of accounting for income taxes. The new standard was effective for us prospectively for annual reporting periods beginning after December 15, 2020, and interim periods therein. Early adoption was permitted, which we elected not to do. The adoption of this standard on January 1, 2021 did not have 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.

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, if any, are typically billed and recognized in equal monthly installments over the term of the 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 nine-month periods ended September 30, 2021 and 2020, we provided approximately 61% and 57% 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 2021, 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 consolidated balance sheets. At September 30, 2021 and September 30, 2020, we recognized refund liabilities totaling $16,500,000 and $21,400,000, respectively. 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 nine months ended September 30, 2021 and 2020 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	(dollars in thousands)			
	2021	2020	**2021**	2020
Capacity revenues	**$ 228,048**	$ 222,187	**$ 716,303**	$ 721,836
Energy revenues	**209,192**	143,750	**455,130**	316,382
Total	**$ 437,240**	$ 365,937	**$ 1,171,433**	$ 1,038,218
Member energy requirements supplied	**65 %**	60 %	**61 %**	57 %

Receivables from contracts with our members at September 30, 2021 and December 31, 2020 were $156,095,000 and $135,462,000, respectively.

Sales to non-members during the three and nine months ended September 30, 2021 and 2020 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	(dollars in thousands)			
	2021	2020	**2021**	2020
Energy revenues	**$ 23,582**	$ 302	**$ 23,847**	$ 639

Receivables from non-member energy sales at September 30, 2021 and December 31, 2020 were $6,562,000 and $0, respectively.

Energy revenues to non-members for the three and nine months ended September 30, 2021 were primarily from the sale of the Effingham Energy Facility's (Effingham) output into the wholesale market. See Note O for additional information regarding the Effingham acquisition. There were no capacity revenues to non-members for the three and nine months ended September 30, 2021 and 2020.

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, 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 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. The Vogtle program allows for the recovery of financing costs associated with the construction of Vogtle Units No. 3 and No. 4 on a current basis. Under this program, amounts billed to participating members during the nine months ended September 30, 2021 and 2020 were $11,601,000 and $11,805,000, respectively. The cumulative amount billed since inception of the program totaled $107,544,000.

In 2018, we began a 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. Under this program, amounts billed to participating members during the nine months ended September 30, 2021 and 2020 were $115,837,000 and $93,390,000, respectively. Funds collected through this program are invested and held until applied to members' bills. 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 cumulative amount billed since inception of the program totaled $330,165,000.

In 2021, we implemented an additional rate management program that allows the Effingham deferring members to pay all or a portion of their share of the regulatory asset balance on a current basis. The cumulative amount billed since inception of the program totaled $191,000. See Note O for additional information regarding the Effingham acquisition.

(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 nine months ended September 30, 2021 and 2020 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 or liability. Finance lease amortization is recorded in depreciation and amortization expense.

Operating Leases

Our railcar operating leases have terms that extend through March 16, 2024. 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	**September 30, 2021**	December 31, 2020
	(dollars in thousands)	
Right-of-Use Assets—Finance leases		
Right-of-use assets	**$ 302,732**	$ 302,732
Less: Accumulated provision for depreciation	**(266,288)**	(262,774)
Total finance lease assets	**$ 36,444**	$ 39,958
Lease liabilities—Finance leases		
Obligations under finance leases	**$ 65,207**	$ 68,876
Long-term debt and finance leases due within one year	**7,146**	6,773
Total finance lease liabilities	**$ 72,353**	$ 75,649

Classification	September 30, 2021	December 31, 2020
	(dollars in thousands)	
Right-of-Use Assets—Operating leases		
Electric plant in service	**$ 2,540**	$ 3,283
Total operating lease assets	**$ 2,540**	$ 3,283
Lease liabilities—Operating leases		
Capitalization—Other	**$ 1,677**	$ 2,388
Other current liabilities	**876**	990
Total operating lease liabilities	**$ 2,553**	$ 3,378

Lease Cost	Classification	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
		(dollars in thousands)			
Finance lease cost:					
Amortization of leased assets	Depreciation and amortization	**$ 1,693**	$ 1,344	**$ 4,726**	$ 4,032
Interest on lease liabilities	Interest expense	**2,045**	2,217	**6,133**	6,651
Operating lease cost:	Inventory[1] & production expense	**270**	286	**809**	1,081
Total leased cost		**$ 4,008**	$ 3,847	**$ 11,668**	$ 11,764

[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.

	September 30, 2021	December 31, 2020
Lease Term and Discount Rate:		
Weighted-average remaining lease term (in years)		
Finance leases	**7.13**	7.86
Operating leases	**8.01**	7.27
Weighted-average discount rate:		
Finance leases	**11.05 %**	11.05 %
Operating leases	**4.76 %**	4.63 %

	Nine months ended September 30, 2021	Nine months ended September 30, 2020
	(dollars in thousands)	
Other Information:		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance leases	**$ 4,180**	$ 4,516
Operating cash flows from operating leases	**$ 890**	$ 1,301
Financing cash flows from finance leases	**$ 3,295**	$ 2,959
Right-of-use assets obtained in exchange for new operating lease liabilities	**$ —**	$ —

Maturity analysis of our finance and operating lease liabilities at September 30, 2021 is as follows:

	(dollars in thousands)		
Year Ending December 31,	**Finance Leases**	**Operating Leases**	**Total**
2021	$ 7,474	$ 230	$ 7,704
2022	14,949	929	15,878
2023	14,949	708	15,657
2024	14,949	234	15,183
2025	14,949	72	15,021
Thereafter	40,582	1,011	41,593
Total lease payments	$ 107,852	$ 3,184	$ 111,036
Less: imputed interest	(35,499)	(631)	(36,130)
Present value of lease liabilities	$ 72,353	$ 2,553	$ 74,906

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 nine months ended September 30, 2021 and 2020 was as follows:

	Three Months Ended September 30,		**Nine months ended September 30,**	
	2021	2020	**2021**	2020
	(dollars in thousands)			
Lease income	**$ 1,603**	$ 1,543	**$ 4,806**	$ 4,633

(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 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.

On July 29, 2020, a group of individual plaintiffs filed a complaint in the Superior Court of Fulton County, Georgia against Georgia Power alleging that releases from Plant Scherer, of which we are a co-owner, have impacted groundwater, surface water, and air, resulting in alleged personal injuries and property damage. On October 8, 2021, three additional complaints were filed in the Superior Court of Monroe County, Georgia against Georgia Power alleging that releases from Plant Scherer have impacted groundwater and air, resulting in alleged personal injuries and property damage. The plaintiffs seek an unspecified amount of monetary damages including punitive damages, a medical monitoring fund, and injunctive relief.

(I) *Restricted Cash and Investments.* Restricted investments consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account that are held by the U.S. Treasury, acting through the Federal Financing Bank. We can only utilize these investments for future Rural Utilities Service-guaranteed Federal Financing Bank debt service payments. As of October 1, 2020, deposits earned interest at 4% per annum. Beginning October 1, 2021, the rate was set at the 1-year floating treasury rate, which was 0.09% per annum, and will reset annually on October 1 of each year thereafter. The program no longer allows additional funds to be deposited into the account. At September 30, 2021 and December 31, 2020, we had restricted investments totaling $319,980,000 and $487,587,000, respectively, of which $73,400,000 and $306,601,000, respectively, were classified as long-term.

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	Nine months ended	
	September 30, 2021	September 30, 2020
	(dollars in thousands)	
Cash and cash equivalents	**$ 452,943**	$ 383,868
Restricted cash included in Prepayments and other current assets	**3,400**	—
Total cash, cash equivalents and restricted cash reported in the consolidated statements of cash flows	**$ 456,343**	$ 383,868

(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 unaudited consolidated balance sheets at September 30, 2021 and December 31, 2020.

	2021	2020
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt(a)	**$ 34,307**	$ 35,433
Amortization of financing leases(b)	**34,555**	35,328
Outage costs(c)	**36,734**	35,232
Asset retirement obligations—Ashpond and other(k)	**272,923**	242,832
Depreciation expense - other(d)	**37,329**	38,396
Depreciation expense - Plant Wansley(e)	**149,641**	—
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs(f)	**55,702**	55,430
Interest rate options cost(g)	**130,367**	126,813
Deferral of effects on net margin—Smith Energy Facility(h)	**144,161**	148,620
Other regulatory assets(o)	**2,398**	13,354
Total Regulatory Assets	**$ 898,117**	$ 731,438
Regulatory Liabilities:		
Accumulated retirement costs for other obligations(i)	**$ 21,124**	$ 20,054
Deferral of effects on net margin—Hawk Road Energy Facility(h)	**17,407**	17,869
Major maintenance reserve(j)	**61,127**	39,776
Amortization of financing leases(b)	**9,182**	11,356
Deferred debt service adder(k)	**134,833**	123,772
Asset retirement obligations—Nuclear(l)	**142,368**	130,901
Revenue deferral plan(m)	**334,645**	220,111
Natural gas hedges(n)	**93,930**	—
Other regulatory liabilities(o)	**1,613**	2,560
Total Regulatory Liabilities	**$ 816,229**	$ 566,399
Net Regulatory Assets	**$ 81,888**	$ 165,039

(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 22 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 is expected as early as fall of 2022. Amortization will commence upon retirement of Plant Wansley and 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 will commence when Vogtle Unit No. 3 is placed in service.

(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 allows for additional collections over a five-year period which began in 2018. These amounts will be amortized to income and applied to member billings over the subsequent five-year period.

(n) Represents deferral associated with unrealized gains on our natural gas hedges.

(o) The amortization periods for other regulatory assets range up to 29 years and the amortization periods of other regulatory liabilities range up to 6 years.

(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 2026, with the majority of the balance scheduled to be credited by the end of 2023.

(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 multi-advance term loan facility (the Facility) under which we may make long-term loan borrowings through the Federal Financing Bank.

Proceeds of advances made under the Facility are used to reimburse us for a portion of certain costs of construction relating to Vogtle Units No. 3 and No. 4 that are eligible for financing under the Title XVII loan guarantee program (Eligible Project Costs). Borrowings under the Original FFB Notes could not exceed $3,057,069,461, of which $335,471,604 was designated for capitalized interest. We have advanced all amounts available under the Original FFB Notes. We were unable to advance $43,721,079 of the amount designated for capitalized interest under the Original FFB Notes due to timing of borrowing and lower than expected interest rates.

Borrowings under the Additional FFB Note may not exceed (i) $1,619,679,706 or (ii) an amount that, when aggregated with borrowings under the Original FFB Notes, equals 70% of Eligible Project Costs less the $1,104,000,000 guarantee payment we received from Toshiba Corporation in late 2017. At September 30, 2021, borrowings under the Additional FFB Note totaled $867,000,000.

At September 30, 2021, aggregate Department of Energy-guaranteed borrowings, including capitalized interest, totaled $3,880,348,382.

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. The final maturity date for each advance is February 20, 2044. Interest is payable quarterly in arrears and principal payments on all advances under the FFB Notes began on February 20, 2020. As of September 30, 2021, we have repaid $158,313,000 of principal on the FFB Notes. Interest rates on advances during the applicable interest rate periods will equal the current average yield on U.S. Treasuries of comparable maturity at the beginning of the interest rate period, plus a spread equal to 0.375%.

Advances under the Additional FFB Note may be requested on a quarterly basis through November 30, 2023.

Future advances under the Facility are subject to satisfaction of customary conditions, as well as (i) certification of compliance with the requirements of the Title XVII loan guarantee program, (ii) accuracy of project-related representations and warranties, (iii) delivery of updated project-related information, (iv) no Project Adverse Event (as described in Note M) having occurred or, if a Project Adverse Event has occurred, that Co-owners (as described in Note M) representing at least 90% of the ownership interests have voted to continue construction, have not deferred construction and we have provided the Department of Energy with certain additional information, (v) certification regarding Georgia Power's compliance with certain obligations relating to the Cargo Preference Act, as amended, (vi) evidence of compliance with the applicable wage requirements of the Davis-Bacon Act, as amended, (vii) certification from the Department of Energy's consulting engineer that proceeds of the advance are used to reimburse Eligible Project Costs and (viii) if either the Services Agreement or the Bechtel Agreement (each, as described in Note M) are terminated, or rejected in bankruptcy proceedings, the Department of Energy has approved the replacement agreement.

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 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 the Federal Financing Bank's commitment to make further advances under the Facility will terminate and 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 nine-month period ended September 30, 2021, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $270,524,000 for long-term financing of general and environmental improvements at existing plants.

In October 2021, we received an additional $12,508,000 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:*

In August 2021, we redeemed $245,605,000 of Series 2009 and 2010 pollution control revenue bonds.

d) *Lines of Credit:*

On October 1, 2021, we amended our bilateral credit facility with JPMorgan Chase to extend the expiration date to October 2024 and reduce the commitment amount from $363,000,000 to $350,000,000.

(M) *Vogtle Units No. 3 and No. 4 Construction Project.* We, Georgia Power, the Municipal Electric Authority of Georgia, 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. Our ownership interest and proportionate share of the cost to construct these units is 30%. 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). The Bechtel Agreement is a cost reimbursable plus fee arrangement, whereby Bechtel is reimbursed for actual costs plus a base fee and an at-risk fee, which is 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.

At September 30, 2021, our total investment for our 30% interest in the additional Vogtle units was approximately $6.8 billion. We and some of our members have implemented various rate management programs to lessen the impact on rates when Vogtle Units No. 3 and No. 4 reach commercial operation.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts on a regular basis to incorporate current information available, particularly in the areas of engineering support, commodity installation, system turnovers and related test results, and workforce statistics.

In mid-March 2020, Southern Nuclear began implementing policies and procedures designed to mitigate the risk of transmission of COVID-19 at the construction site, including worker distancing measures, isolating individuals who tested positive for COVID-19, showed symptoms consistent with COVID-19, were being tested for COVID-19, or were in close contact with such persons, requiring self-quarantine, and adopting additional precautionary measures. Since March 2020, the number of active cases of COVID-19 at the site has fluctuated and impacted productivity levels and pace of activity completion. As a result, the project has faced challenges, including, but not limited to, higher than expected absenteeism; overall construction and subcontractor labor productivity; system turnover and testing activities; and electrical equipment and commodity installation.

In 2021, Southern Nuclear has been performing additional construction remediation work necessary to ensure quality and design standards are met as system turnovers are completed to support hot functional testing, which was completed in July 2021, and fuel load for Unit No. 3. As a result of challenges including, but not limited to, construction productivity, construction remediation work, the pace of system turnovers, spent fuel pool repairs, and the timeframe and duration for hot functional testing and other testing, at the end of the second quarter 2021, Southern Nuclear further extended certain milestone dates. Through the third quarter 2021, the project continued to face challenges including, but not limited to, construction productivity, construction remediation work, and the pace of system turnovers and Georgia Power has disclosed that it projects an in-service date for Unit No. 3 in the third quarter of 2022. Our current budget reflects our expectation of an in-service date for Unit No. 3 in September 2022.

As a result of productivity challenges, at the end of the second quarter 2021 Southern Nuclear also further extended milestone dates for Unit No. 4. Those productivity challenges continued into the third quarter and, in addition, some craft and support resources were diverted temporarily to support construction efforts on Unit No. 3. The in-service date for Unit No. 4 primarily depends on overall construction productivity as well as appropriate levels of craft laborers, particularly electrical and pipefitter craft labor, being added and maintained. Georgia Power has disclosed that it projects an in-service date for Unit No. 4 in second quarter 2023. Our current budget anticipates an in-service date for Unit No. 4 in June 2023.

During the fourth quarter of 2020, Georgia Power established $375 million of additional contingency (of which our 30% share was $112.5 million). At March 31, 2021, Georgia Power assigned approximately $183 million (of which our 30% interest was $55 million) of that construction contingency to the base capital cost forecast for costs primarily associated with the schedule extension for Unit No. 3 to December 2021, construction productivity, support resources and construction remediation work. During the first quarter of 2021, Georgia Power also established an additional $106 million of construction contingency (of which our 30% share was $32 million). At June 30, 2021, the remaining previously established project-level contingency of approximately $300 million (of which our 30% interest was $90 million) and an additional $746 million (of which our 30% interest was $224 million) was assigned to the base capital cost forecast for costs primarily associated with the schedule extensions for Units No. 3 and No. 4, construction remediation work for Unit No. 3, and construction productivity and support resources for Units No. 3 and No. 4. At June 30, 2021, Georgia Power also established an additional $260 million of construction contingency (of which our 30% interest was $78 million) to replenish the project-level construction contingency. Considering the factors above, during the third quarter 2021, the construction contingency established in the second quarter and an additional $278 million (of which our 30% share was $83 million) was assigned to the base capital cost forecast for costs primarily associated with the schedule extensions for Units No. 3 and No. 4, construction productivity and support resources for Units No. 3 and No. 4, and construction remediation work for Unit No. 3. At September 30, 2021, Georgia Power added $300 million (of which our 30% interest is $90 million) to replenish construction contingency. Georgia Power has stated its expectation to allocate the remainder of this project-level contingency by completion of the project.

In addition, the continuing effects of the COVID-19 pandemic could further disrupt or delay construction, testing, supervisory, and support activities at Vogtle Units No. 3 and No. 4. The incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity is currently estimated by Georgia Power to be between $350 million and $438 million (of which our 30% interest is $105 million to $131 million) and is included in the project budget.

Our budget for our 30% ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs, allowance for funds used during construction, our allocation of the project-level contingency and a separate Oglethorpe-level contingency, is $8.25 billion and is based on commercial operation dates of September 2022 and June 2023 for Units No. 3 and No. 4, respectively.

The project-level contingency is separate and in addition to our Oglethorpe-level contingency. The Oglethorpe-level contingency, which we have carried at various levels since the beginning of the project, provides additional margin to cover potential cost, schedule, and financing risks associated with our share of the project which may not be covered by project-level contingencies. As construction progresses, the Oglethorpe-level contingency may continue to fluctuate as it represents the difference between known project-level costs and contingencies and our total budget of $8.25 billion. At the end of the project, if there is remaining Oglethorpe-level contingency, we will adjust our project budget to remove this contingency and bill our members based on the actual project costs. The table below shows our project budget and actual costs through September 30, 2021 for our 30% interest in the project.

	(in millions)		
	Project Budget	Actual Costs at September 30, 2021	Remaining Project Budget
Construction Costs [1]	$ 6,140	$ 5,342	$ 798
Financing Costs	1,778	1,443	335
Total Costs	$ 7,918	$ 6,785	$ 1,133
Project-Level Contingency	$ 90	$ —	$ 90
Oglethorpe-Level Contingency	242	—	242
Total Contingency	$ 332	$ —	$ 332
Totals	$ 8,250	$ 6,785	$ 1,465

[1] Construction costs are net of $1.1 billion received from Toshiba Corporation under a Guarantee Settlement Agreement.

The Oglethorpe-level contingency in our current budget is expected to be sufficient to cover a few months of additional delays beyond our assumed in-service dates of September 2022 and June 2023 for Unit No. 3 and Unit No. 4, respectively, such as a three-month delay on Unit No. 4 from June 2023 to September 2023. Any further delays are expected to impact our cost by approximately $55 million per month for both units and approximately $25 million per month for Unit No. 4 only, including financing costs.

As construction, including subcontract work, continues and testing and system turnover activities increase, risks remain that ongoing or future challenges with management of contractors and vendors; subcontractor performance; supervision of craft labor and related productivity, particularly in the installation of electrical, mechanical, and instrumentation and controls commodities, ability to attract and retain craft labor, and/or related cost escalation; procurement, fabrication, delivery, assembly, installation, system turnover, and the initial testing and start-up, including any required engineering changes or any remediation related thereto, of 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), including the spent fuel pools, any of which may require additional labor and/or materials; or other issues could arise and further impact the projected schedule and estimated cost.

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. In connection with the additional construction remediation work described above, Southern Nuclear reviewed the project's construction quality programs and, where needed, is implementing improvement plans consistent with these processes. In June 2021, the Nuclear Regulatory Commission began a special inspection to review the root cause of this additional construction remediation work and the corresponding corrective action plans. On August 26, 2021, the Nuclear Regulatory Commission made preliminary findings of two apparent violations of Nuclear Regulatory Commission regulations, one of low to moderate safety significance, and the other of greater than very low safety significance. The Nuclear Regulatory Commission also made a finding of very low safety significance related to a non-cited violation of its regulations. The Nuclear Regulatory Commission stated that the apparent nonconformances associated with these findings do not represent an immediate safety concern because Unit No. 3 construction is still underway and issues implicating inspections, tests, analyses, and acceptance criteria must be resolved prior to loading nuclear fuel into the Unit No. 3 reactor. Findings from this or other inspections could require additional remediation and/or further Nuclear Regulatory Commission oversight and may impact the projected in-service dates. In addition, certain license amendment requests have been filed and approved or are pending before the Nuclear Regulatory Commission.

Various design and other licensing-based compliance matters, including the timely submittal by Southern Nuclear of the inspections, tests, analyses, and acceptance criteria documentation for each unit and the related reviews and approvals by the Nuclear Regulatory Commission necessary to support authorization to load fuel, have arisen or may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues, including inspections, tests, analyses, and acceptance criteria, 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.

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 (VCM) report 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 that mitigated 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 nineteenth VCM report 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 the nineteenth VCM report 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 the nineteenth VCM report 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 the nineteenth VCM report by more than $2.1 billion, each of the Co-owners, other than Georgia Power, will have a one-time option to be exercised between 120 and 180 days following the date the revised construction budget is voted on by the Co-owners 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 remaining share of construction costs in excess of the EAC in the nineteenth VCM report plus $2.1 billion. In this event, Georgia Power would have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Co-owner. If Georgia Power accepts the offer to purchase a portion of another Co-owner's ownership interest in Vogtle Units No. 3 and No. 4, the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Co-owner and by Georgia Power as of the commercial operation date of Vogtle Unit No. 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Co-owner in accordance with the second and third bullets above will be treated as payments made by the applicable Co-owner. This option to tender a portion of our interest to Georgia Power upon such a budget increase would allow us to freeze our construction budget associated with the Vogtle project in exchange for a portion of our 30% ownership interest.

Georgia Power and the other Co-owners do not agree on (i) the starting dollar amount for each Co-owner's option to tender a portion of its ownership interest to Georgia Power under the freeze provision of the Global Amendments or (ii) the starting dollar amount and extent to which costs that are the result of a Force Majeure Event (such as COVID-19) impact the calculation of the cost-sharing provisions of the Global Amendments. The nineteenth VCM report total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. At September 30, 2021, budget increases since the nineteenth VCM have reached $2.4 billion for all Co-owners. As a result of these increases, we believe that the tender option will be triggered at the next Co-owner construction budget vote scheduled for February 2022 and that Georgia Power's obligation to contribute dollars to the Co-owners under the cost-sharing provisions will commence as early as the first half of 2022. Georgia Power and the other Co-owners recently clarified the process for the freeze provision to provide for a decision between 120 and 180 days after the tender option is triggered which will provide additional time to resolve these matters.

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

(N) *Measurement of Credit Losses on Financial Instruments.* The financial assets we hold that are subject to the new credit losses standard 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 Acquisition.* On July 8, 2021, we acquired Effingham County Power, LLC, which owned the Effingham Energy Facility located near Savannah, Georgia, from Effingham County Power Holdings, LLC, an affiliate of the Carlyle Group, Inc. Effingham consists of a natural gas-fired combined cycle unit with an aggregate summer planning reserve generation capacity of approximately 511 megawatts. Subsequently, we dissolved Effingham County Power, LLC and transferred all of its assets and liabilities to Oglethorpe.

The purchase price was $233,156,000 and the acquisition also included other transaction costs of approximately $1,382,000 (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 and have received a conditional loan commitment from 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 Effingham acquisition:

Classification		
		(dollars in thousands)
Recognized identifiable assets acquired and liabilities assumed:		
Electric plant in service, net	**$**	**229,215**
Inventories, at average cost		**3,264**
Other current assets		**3,167**
Other current liabilities		**(2,490)**
Total identifiable net assets	**$**	**233,156**

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 Effingham, their share of output is being sold into the wholesale market. Revenues and costs of output taken by scheduling members are being recognized in the current period. Residual net results of operations from Effingham, including related interest costs, are being deferred as a regulatory asset. This regulatory asset will be amortized over the then remaining life of the plant, estimated to be 22 years at January 2026. If a deferring member elects to take service before January 2026, amortization 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.

Response to COVID-19

To date, we have successfully navigated the challenges presented by the COVID-19 pandemic and are proud of our associates' response. As an electric utility, we are deemed part of the nation's critical infrastructure and continued operating during the pandemic to provide electricity to our members and the populations they serve. In June 2021, we completed the reopening of our corporate offices with new safety protocols intended to reduce the risk of transmission of COVID-19. We continue to keep in contact with state and federal regulators to ensure the safety of our associates and reliability of our generation facilities. The ultimate impact of the pandemic on us and our members remains subject to many factors, including the remaining duration and severity of the COVID-19 pandemic and the resulting economic conditions.

Results of Operations

For the Three and Nine Months Ended September 30, 2021 and 2020

Net Margin

Our net margins for the three-month and nine-month periods ended September 30, 2021 were \$8.9 million and \$48.0 million compared to \$8.5 million and \$57.8 million for the same periods of 2020. Through September 30, 2021, we collected approximately 83% of our targeted net margin of \$57.8 million for the year ending December 31, 2021. 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 2021 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 \$16.5 million and \$21.4 million at September 30, 2021 and September 30, 2020, 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 2020 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.

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 nine-month periods ended September 30, 2021 and 2020 were as follows:

	Three Months Ended September 30, (dollars in thousands)			Nine Months Ended September 30, (dollars in thousands)		
	2021	2020	% Change	**2021**	2020	% Change
Capacity revenues	**$228,048**	$ 222,187	2.6 %	**$716,303**	$721,836	(0.8)%
Energy revenues	**209,192**	143,750	45.5 %	**455,130**	316,382	43.9%
Total	**$437,240**	$ 365,937	19.5 %	**$1,171,433**	$1,038,218	12.8%
MWh Sales to members	**7,566,980**	7,147,341	5.9 %	**18,727,189**	17,028,641	10.0%
Cents/kWh	**5.78**	5.12	12.9 %	**6.26**	6.10	2.6%
Member energy requirements supplied	**65 %**	60 %	8.3 %	**61 %**	57 %	7.0 %

Energy revenues from members increased for the three-month and nine-month periods ended September 30, 2021 compared to the same periods in 2020 primarily due to the recovery of fuel costs. The increase in megawatt-hours sold to members also contributed to the increase in energy revenues. For a discussion of fuel costs, which are the primary costs recovered by energy revenues, see "—*Operating Expenses*."

Sales to non-members. Energy revenues to non-members were primarily due from the sale of the Effingham deferring members' output into the wholesale market. See Note O of Notes to Unaudited Consolidated Financial Statements for additional information regarding the Effingham acquisition. There were no capacity revenues to non-members for the three and nine months ended September 30, 2021 and 2020.

Sales to non-members during the three and nine months ended September 30, 2021 and 2020 were as follows:

	Three Months Ended September 30, (dollars in thousands)		**Nine Months Ended September 30,**	
	2021	2020	**2021**	2020
Energy revenues	**$ 23,582**	$ 302	**$ 23,847**	$ 639

Operating Expenses

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

	Cost (dollars in thousands) Three Months Ended September 30,			**Generation** (MWh) Three Months Ended September 30,			**Cents per kWh** Three Months Ended September 30,		
Fuel Source	**2021**	2020	% Change	**2021**	2020	% Change	**2021**	2020	% Change
Coal	**$ 50,384**	$ 29,852	68.8%	**1,535,053**	884,482	73.6%	**3.28**	3.38	(3.0)%
Nuclear	**18,849**	19,258	(2.1)%	**2,434,355**	2,459,582	(1.0)%	**0.77**	0.78	(1.3)%
Gas:									
Combined Cycle	**121,220**	57,752	109.9%	**3,885,404**	3,192,130	21.7%	**3.12**	1.81	72.4%
Combustion Turbine	**24,228**	25,063	(3.3)%	**489,436**	807,183	(39.4)%	**4.95**	3.10	59.7%
	$214,681	$131,925	62.7%	**8,344,248**	7,343,377	13.6%	**2.57**	1.80	42.8%

	Cost (dollars in thousands)			Generation (MWh)			Cents per kWh		
	Nine Months Ended September 30,			Nine Months Ended September 30,			Nine Months Ended September 30,		
Fuel Source	**2021**	2020	% Change	**2021**	2020	% Change	**2021**	2020	% Change
Coal	**$ 86,061**	$ 34,767	147.5%	**2,559,235**	982,095	160.6%	**3.36**	3.54	(5.1)%
Nuclear	**57,853**	55,784	3.7%	**7,529,053**	7,165,407	5.1%	**0.77**	0.78	(1.3)%
Gas:									
Combined Cycle	**252,472**	153,934	64.0%	**8,876,229**	8,071,682	10.0%	**2.84**	1.91	48.7%
Combustion Turbine	**39,891**	38,191	4.5%	**873,175**	1,261,013	(30.8)%	**4.57**	3.03	50.8%
	$436,277	$282,676	54.3%	**19,837,692**	17,480,197	13.5%	**2.20**	1.62	35.8%

Total fuel costs increased for the three-month and nine-month periods ended September 30, 2021 compared to the same periods in 2020 as a result of an increase in the average cost of fuel as well as an increase in generation. The increase in average fuel cost was primarily due to higher average natural gas prices in 2021 as prices have increased due to supply and demand pressures. Coal-fired generation increased primarily as a result of the higher average natural gas prices, which caused generation from the coal-fired units to be more economical. The overall increase in generation for the three-month and nine-month periods ended September 30, 2021 compared to the same periods in 2020 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 can vary due to the number and extent of maintenance outages in a given year. Production costs decreased slightly for the nine-month period ended September 30, 2021 as compared to the same period of 2020 primarily as a result of lower fixed major maintenance outage costs at our combined cycle plants. Largely offsetting this decrease were higher fixed major maintenance outage costs at our combustion turbine plants and higher fixed operational costs at our coal-fired and nuclear plants. Production costs increased slightly for the three-month period ended September 30, 2021 as compared to the same period of 2020 primarily as a result of higher fixed operational costs at our combined cycle and combustion turbine plants.

Interest Charges

Net interest charges decreased slightly for the three-month and nine-month periods ended September 30, 2021 as compared to the same periods of 2020 as a result of the capitalization of interest expense associated with construction expenditures for Vogtle Units No. 3 and No. 4.

Financial Condition

Balance Sheet Analysis as of September 30, 2021

Assets

Cash used for property additions for the nine-month period ended September 30, 2021 totaled $1.1 billion. Of this amount, $744.0 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, $233.2 million for the Effingham acquisition and $59.4 million was for nuclear fuel purchases. The remainder was for expenditures related to normal additions and replacements to our existing generation facilities.

Nuclear decommissioning trust fund investments increased $37.8 million for the nine-month period ended September 30, 2021 due to a $21.8 million increase in the fair value of the investments and $16.0 million in investment earnings.

Long-term investments increased $160.6 million for the nine-month period ended September 30, 2021 primarily due to purchases under one of our member rate management programs. Funds collected through this rate management program are invested and held until applied to members' bills. At September 30, 2021, total amounts invested under this program, including earnings, during 2021 were $119.1 million. In addition, funds invested, including earnings, during 2021 in our internal nuclear decommissioning fund, coal ash remediation funds and major maintenance reserve funds were $40.9 million. See Note F of Notes to Unaudited Consolidated Financial Statements for a discussion of our member rate management programs.

Restricted investments consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. We can only utilize these investments for future Rural Utilities Service-guaranteed Federal Financing Bank debt service payments. The program no longer allows additional funds to be deposited into the account. During the nine-month period ended September 30, 2021, we utilized $180.6 million for debt service payments and expect to utilize the remainder of the balance through 2023. For additional information regarding restricted investments, see Note I of Notes to Unaudited Consolidated Financial Statements.

Receivables increased $52.7 million during the nine-month period ended September 30, 2021 largely due to a $27.2 million increase in receivables from members and non-members as a result of increased sales, a $13.1 million receivable related to natural gas purchases and an $8.9 million increase in receivables from associated organizations for operations and management services.

Inventories decreased $43.3 million during the nine-month period ended September 30, 2021 primarily due to increased generation at our coal-fired plants and the associated increase in coal burn.

Prepayments and other current assets increased $60.5 million during the nine-month period ended September 30, 2021 primarily due to a $47.1 million increase in fair value at September 30, 2021 of our natural gas hedges and a $15.4 million increase in prepaid major maintenance outage costs.

Regulatory assets increased $166.7 million largely as a result of a $149.6 million increase in the deferral of accelerated depreciation associated with the early retirement of Plant Wansley, which is expected as early as fall of 2022. The increase in our regulatory assets was also attributable to the $30.3 million increase in the deferral associated with our coal ash pond asset retirement obligations. These increases were partially offset by a $10.2 million decrease in unrealized losses on our natural gas hedges, which were in an unrealized gain position at September 30, 2021.

Other deferred charges increased $38.9 million during the nine-month period ended September 30, 2021 primarily due to a $46.6 million increase in fair value at September 30, 2021 of our natural gas hedges.

Equity and Liabilities

Long-term debt and long-term debt and finance leases due within one year increased $86.9 million primarily as a result of a $247.0 million advance under the Department of Energy loan guarantee and $270.5 million in advances under the Rural Utilities Service-guaranteed Federal Financing Bank loan. Offsetting this increase was $440.6 million in debt service payments, including the redemption of $245.6 million of Series 2009 and 2010 pollution control revenue bonds. 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 and the Effingham acquisition, increased $639.9 million during the nine-month period ended September 30, 2021. During this period, total short-term borrowings were $1.1 billion and repayments totaled $427.5 million.

Regulatory liabilities increased $249.8 million for the nine-month period ended September 30, 2021 primarily due to a $114.5 million increase in the deferral plan associated with one of our member rate management programs. In addition, there was a $93.9 million increase associated with unrealized gains on our natural gas hedges and a $21.4 million increase in collections for future major maintenance outages. Additionally, there was an $11.5 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.

Asset retirement obligations increased $78.5 million for the nine-month period ended September 30, 2021 primarily due to change in cash flow estimates of $38.9 million related to coal ash pond decommissioning and $41.8 million in accretion expense.

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4

We, Georgia Power, the Municipal Electric Authority of Georgia, 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. Our ownership interest and proportionate share of the cost to construct these units is 30%. 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.

At September 30, 2021, our total investment for our 30% interest in the additional Vogtle units was approximately $6.8 billion. We and some of our members have implemented various rate management programs to lessen the impact on rates when Vogtle Units No. 3 and No. 4 reach commercial operation.

As part of its ongoing processes, Southern Nuclear continues to evaluate cost and schedule forecasts on a regular basis to incorporate current information available, particularly in the areas of engineering support, commodity installation, system turnovers and related test results and workforce statistics.

In mid-March 2020, Southern Nuclear began implementing policies and procedures designed to mitigate the risk of transmission of COVID-19 at the construction site, including worker distancing measures; isolating individuals who tested positive for COVID-19, showed symptoms consistent with COVID-19, were being tested for COVID-19, or were in close contact with such persons; requiring self-quarantine; and adopting additional precautionary measures. Since March 2020, the number of active cases of COVID-19 at the site has fluctuated and impacted productivity levels and pace of activity completion. As a result, the project has faced challenges, including, but not limited to, higher than expected absenteeism; overall construction and subcontractor labor productivity; system turnover and testing activities; and electrical equipment and commodity installation.

In 2021, Southern Nuclear has been performing additional construction remediation work necessary to ensure quality and design standards are met as system turnovers are completed to support hot functional testing, which was completed in July 2021, and fuel load for Unit No. 3. As a result of challenges including, but not limited to, construction productivity, construction remediation work, the pace of system turnovers, spent fuel pool repairs, and the timeframe and duration for hot functional testing and other testing, at the end of the second quarter 2021, Southern Nuclear further extended certain milestone dates. Through the third quarter 2021, the project continued to face challenges including, but not limited to, construction productivity, construction remediation work, and the pace of system turnovers and Georgia Power has disclosed that it projects an in-service date for Unit No. 3 in the third quarter of 2022. Our current budget reflects our expectation of an in-service date for Unit No. 3 in September 2022.

As a result of productivity challenges, at the end of the second quarter 2021 Southern Nuclear also further extended milestone dates for Unit No. 4. Those productivity challenges continued into the third quarter and, in addition, some craft and support resources were diverted temporarily to support construction efforts on Unit No. 3. The in-service date for Unit No. 4 primarily depends on overall construction productivity as well as appropriate levels of craft laborers, particularly electrical and pipefitter craft labor, being added and maintained. Georgia Power has disclosed that it projects an in-service date for Unit No. 4 in second quarter 2023. Our current budget anticipates an in-service date for Unit No. 4 in June 2023.

During the fourth quarter of 2020, Georgia Power established $375 million of additional contingency (of which our 30% share was $112.5 million). At March 31, 2021, Georgia Power assigned approximately $183 million (of which our 30% interest was $55 million) of that construction contingency to the base capital cost forecast for costs primarily associated with the schedule extension for Unit No. 3 to December 2021, construction productivity, support resources and construction remediation work. During the first quarter of 2021, Georgia Power also established an additional $106 million of construction contingency (of which our 30% share was $32 million). At June 30, 2021, the remaining previously established project-level contingency of approximately $300 million (of which our 30% interest was $90 million) and an additional $746 million (of which our 30% interest was $224 million) was assigned to the base capital cost forecast for costs primarily associated with the schedule extensions for Units No. 3 and No. 4, construction remediation work for Unit No. 3, and construction productivity and support resources for Units No. 3 and No. 4. At June 30, 2021, Georgia Power also established an additional $260 million of construction contingency (of which our 30% interest was $78 million) to replenish the project-level construction contingency. Considering the factors above, during the third quarter 2021, the construction contingency established in the second quarter and an additional $278 million (of which our 30% share was $83 million) was assigned to the base capital cost forecast for costs primarily associated with the schedule extensions for Units No. 3 and No. 4, construction productivity and support resources for Units No. 3 and No. 4, and construction remediation work for Unit No. 3. At September 30, 2021, Georgia Power added $300 million (of which our 30% interest is $90 million) to replenish construction contingency. Georgia Power has stated its expectation to allocate the remainder of this project-level contingency by completion of the project.

In addition, the continuing effects of the COVID-19 pandemic could further disrupt or delay construction, testing, supervisory, and support activities at Vogtle Units No. 3 and No. 4. The incremental cost associated with COVID-19 mitigation actions and impacts on construction productivity is currently estimated by Georgia Power to be between $350 million and $438 million (of which our 30% interest is $105 million to $131 million) and is included in the project budget.

Our budget for our 30% ownership interest in Vogtle Units No. 3 and No. 4, which includes capital costs, allowance for funds used during construction, our allocation of the project-level contingency and a separate Oglethorpe-level contingency, is $8.25 billion and is based on commercial operation dates of September 2022 and June 2023 for Units No. 3 and No. 4, respectively.

The project-level contingency is separate and in addition to our Oglethorpe-level contingency. The Oglethorpe-level contingency, which we have carried at various levels since the beginning of the project, provides additional margin to cover potential cost, schedule, and financing risks associated with our share of the project which may not be covered by project-level contingencies. As construction progresses, the Oglethorpe-level contingency may continue to fluctuate as it represents the difference between known project-level costs and contingencies and our total budget of $8.25 billion. At the end of the project, if there is remaining Oglethorpe-level contingency, we will adjust our project budget to remove this contingency and bill our members based on the actual project costs. The table below shows our project budget and actual costs through September 30, 2021 for our 30% interest in the project.

	(in millions)		
	Project Budget	Actual Costs at September 30, 2021	Remaining Project Budget
Construction Costs [1]	$ 6,140	$ 5,342	$ 798
Financing Costs	1,778	1,443	335
Total Costs	$ 7,918	$ 6,785	$ 1,133
Project-Level Contingency	$ 90	$ —	$ 90
Oglethorpe-Level Contingency	242	—	242
Total Contingency	$ 332	$ —	$ 332
Totals	$ 8,250	$ 6,785	$ 1,465

[1] Construction costs are net of $1.1 billion received from Toshiba Corporation under a Guarantee Settlement Agreement.

The Oglethorpe-level contingency in our current budget is expected to be sufficient to cover a few months of additional delays beyond our assumed in-service dates of September 2022 and June 2023 for Unit No. 3 and Unit No. 4, respectively, such as a three-month delay on Unit No. 4 from June 2023 to September 2023. Any further delays are expected to impact our cost by approximately $55 million per month for both units and approximately $25 million per month for Unit No. 4 only, including financing costs.

As construction, including subcontract work, continues and testing and system turnover activities increase, risks remain that ongoing or future challenges with management of contractors and vendors; subcontractor performance; supervision of craft labor and related productivity, particularly in the installation of electrical, mechanical, and instrumentation and controls commodities, ability to attract and retain craft labor, and/or related cost escalation; procurement, fabrication, delivery, assembly, installation, system turnover, and the initial testing and start-up, including any required engineering changes or any remediation related thereto, of 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), including the spent fuel pools, any of which may require additional labor and/or materials; or other issues could arise and further impact the projected schedule and estimated cost.

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. In connection with the additional construction remediation work described above, Southern Nuclear reviewed the project's construction quality programs and, where needed, is implementing improvement plans consistent with these processes. In June 2021, the Nuclear Regulatory Commission began a special inspection to review the root cause of this additional construction remediation work and the corresponding corrective action plans. On August 26, 2021, the Nuclear Regulatory Commission made preliminary findings of two apparent violations of Nuclear Regulatory Commission regulations, one of low to moderate safety significance, and the other of greater than very low safety significance. The Nuclear Regulatory Commission also made a finding of very low safety significance related to a non-cited violation of its regulations. The Nuclear Regulatory Commission stated that the apparent nonconformances associated with these findings do not represent an immediate safety concern because Unit No. 3 construction is still underway and issues implicating inspections, tests, analyses, and acceptance criteria must be resolved prior to loading nuclear fuel into the Unit No. 3 reactor. Findings from this or other inspections could require additional remediation and/or further Nuclear Regulatory Commission oversight and may impact the projected in-service dates. In addition, certain license amendment requests have been filed and approved or are pending before the Nuclear Regulatory Commission.

Various design and other licensing-based compliance matters, including the timely submittal by Southern Nuclear of the inspections, tests, analyses, and acceptance criteria documentation for each unit and the related reviews and approvals by the Nuclear Regulatory Commission necessary to support authorization to load fuel, have arisen or may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues, including inspections, tests, analyses, and acceptance criteria, 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.

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 (VCM) report 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 that mitigated 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 nineteenth VCM report 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 the nineteenth VCM report 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 the nineteenth VCM report 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 the nineteenth VCM report by more than $2.1 billion, each of the Co-owners, other than Georgia Power, will have a one-time option to be exercised between 120 and 180 days following the date the revised construction budget is voted on by the Co-owners 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 remaining share of construction costs in excess of the EAC in the nineteenth VCM report plus $2.1 billion. In this event, Georgia Power would have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Co-owner. If Georgia Power accepts the offer to purchase a portion of another Co-owner’s ownership interest in Vogtle Units No. 3 and No. 4, the ownership interest to be conveyed from the tendering Co-owner to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Co-owner and by Georgia Power as of the commercial operation date of Vogtle Unit No. 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Co-owner in accordance with the second and third bullets above will be treated as payments made by the applicable Co-owner. This option to tender a portion of our interest to Georgia Power upon such a budget increase would allow us to freeze our construction budget associated with the Vogtle project in exchange for a portion of our 30% ownership interest.

Georgia Power and the other Co-owners do not agree on (i) the starting dollar amount for each Co-owner’s option to tender a portion of its ownership interest to Georgia Power under the freeze provision of the Global Amendments or (ii) the starting dollar amount and extent to which costs that are the result of a Force Majeure Event (such as COVID-19) impact the calculation of the cost-sharing provisions of the Global Amendments. The nineteenth VCM report total project cost is $17.1 billion (which excludes non-shareable costs) as reflected in numerous Georgia Public Service Commission filings. At September 30, 2021, budget increases since the nineteenth VCM have reached $2.4 billion for all Co-owners. As a result of these increases, we believe that the tender option will be triggered at the next Co-owner construction budget vote scheduled for February 2022 and that Georgia Power’s obligation to contribute dollars to the Co-owners under the cost-sharing provisions will commence as early as the first half of 2022. Georgia Power and the other Co-owners recently clarified the process for the freeze provision to provide for a decision between 120 and 180 days after the tender option is triggered which will provide additional time to resolve these matters.

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

For additional information regarding Vogtle Units No. 3 and No. 4, see "Item 1—BUSINESS—OUR POWER SUPPLY RESOURCES—Future Power Resources—*Plant Vogtle Units No. 3 and No. 4*" in our 2020 Form 10-K. For information regarding our financing of the additional Vogtle units, see "Financing Activities—Department of Energy-Guaranteed Loans" and Note L of Notes to Unaudited Consolidated Financial Statements. See "Item 1A—RISK FACTORS" in our 2020 Form 10-K for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units.

Plant Acquisition: Effingham Energy Facility

On July 8, 2021, we acquired Effingham County Power, LLC, which owned the Effingham Energy Facility (Effingham) located near Savannah, Georgia, from Effingham County Power Holdings, LLC, an affiliate of the Carlyle Group, Inc. for a purchase price of $233.2 million. Effingham consists of a natural gas-fired combined cycle unit with an aggregate summer planning reserve generation capacity of approximately 511 megawatts. See Note O of Notes to Unaudited Consolidated Financial Statements for additional information about this acquisition.

Environmental Regulations

Federal and state laws and regulations regarding environmental matters affect operations at our facilities. On October 13, 2021, Georgia Power, as permit holder and operating agent, notified the Georgia Environmental Protection Division (EPD) that Plant Scherer would comply with the 2020 effluent limitations guidelines (ELG) using the Voluntary Incentives Program (VIP). As such, Plant Scherer will have until December 31, 2028, to install control measures to meet the VIP discharge limitations for applicable wastewater pollutants. Under the ELG rules, Plant Scherer may still switch compliance subcategories to cease the combustion of coal by December 31, 2028, or comply with the generally applicable requirements by December 31, 2025. Additionally, EPD also was informed by Georgia Power on October 13, 2021 that Plant Wansley would comply with the ELG rule by ceasing the combustion of coal (i.e., retirement), which is consistent with previously announced retirement plans.

For additional 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 2020 Form 10-K.

Liquidity

At September 30, 2021, we had $1.2 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $452.9 million in cash and cash equivalents, and $797 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 September 30, 2021		Expiration Date
	(dollars in millions)			
Unsecured Facilities:				
Syndicated Line of Credit led by CFC	$ 1,210	$ 187	(1)	December 2024
CFC Line of Credit(2)	110	110		December 2023
JPMorgan Chase Line of Credit	363	360	(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 September 30, 2021.

(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 September 30, 2021, $2.7 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 which we intend to continue funding with commercial paper until Vogtle Unit No. 4 is placed in service, and
- costs related to the Effingham plant acquisition.

We plan to refinance our commercial paper with long-term debt, either through the issuance of first mortgage bonds, through our loan guaranteed by the Department of Energy, or through financing by the Rural Utilities Service. Our loan guaranteed by the Department of Energy is our preferred source of long-term financing of eligible costs for Vogtle Units No. 3 and No. 4. See Note L of Notes to Unaudited Consolidated Financial Statements and "—Financing Activities—Department of Energy-Guaranteed Loans" for additional information regarding the Department of Energy-guaranteed loans.

Rural Utilities Service financing is our preferred source of long-term financing for the Effingham acquisition and we have received a conditional loan commitment from the Rural Utilities Service for this financing. See Note O of Notes to Unaudited Consolidated Financial Statements for additional information regarding the Effingham acquisition.

We intend to issue first mortgage bonds to provide long-term refinancing of the principal payments we are currently paying under our Department of Energy-guaranteed loans and for all other costs not financed through the Department of Energy or the Rural Utilities Service.

At September 30, 2021, under our unsecured committed lines of credit we had the ability to issue letters of credit totaling $973 million in the aggregate and $657.0 million remained available for the issuance of letters of credit.

On October 1, 2021, we amended our bilateral credit facility with JPMorgan Chase to extend the expiration date to October 2024 and reduce the commitment amount from $363 million to $350 million. We are using this credit facility for letters of credit and plan to use it to support the interim financing needs related to the Effingham acquisition.

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 Effingham acquisition, 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 September 30, 2021, the required minimum level was $750 million and our actual patronage capital was $1.1 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 September 30, 2021, we had $10.7 billion of secured indebtedness and $1.0 billion of unsecured indebtedness outstanding.

At September 30, 2021, we had $320.0 million on deposit in the Rural Utilities Service Cushion of Credit Account, all of which is classified as a restricted investment.

Financing Activities

First Mortgage Indenture. At September 30, 2021, we had $10.7 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 2020 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. At September 30, 2021, we had one approved Rural Utilities Service-guaranteed loan totaling $630.3 million to fund general and environmental improvements that had $359.8 million remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture. At September 30, 2021, we had $2.6 billion of debt outstanding under various Rural Utilities Service-guaranteed loans that is secured under our first mortgage indenture.

Department of Energy-Guaranteed Loans. We have loans from the Federal Financing Bank guaranteed by the Department of Energy to provide funding for over $4.6 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and

No. 4. At September 30, 2021, aggregate Department of Energy-guaranteed borrowings totaled $3.9 billion, including capitalized interest. 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. At September 30, 2021, we had repaid $158.3 million under these loans. If we fully advance these loans, we expect to repay a total of approximately $394 million in principal on these loans by June 2023. We plan to issue first mortgage bonds to refinance the principal repaid before the in-service date of Vogtle Unit No. 4.

Combined, this $4.6 billion and the $2.3 billion of debt we have raised in the capital markets represent long-term financing for more than 84% of our $8.25 billion project budget. We expect to raise long-term financing for the remaining amounts in the capital markets.

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 2020 Form 10-K.

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 2020 Form 10-K.

Item 4. Controls and Procedures

As of September 30, 2021, 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 September 30, 2021 that have materially affected, or are reasonably likely to affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

There have been no material changes to the legal proceedings disclosed in "Item 3—LEGAL PROCEEDINGS" in our 2020 Form 10-K.

For information about loss contingencies that could have an effect on us, see Note H to Unaudited Consolidated Financial Statements.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in "Item 1A—Risk Factors" in our 2020 Form 10-K.

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

Not Applicable.

Item 6. Exhibits

Number	Description
4.1	Eighty-Second Supplemental Indenture, dated as of October 6, 2021, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Recording the Indenture in Effingham County, GA.
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).
101	XBRL Interactive Data File.
104	Cover Page Interactive Data File – (embedded within the Inline XBRL document).

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: November 12, 2021	By:	/s/ Michael L. Smith
		Michael L. Smith President and Chief Executive Officer
Date: November 12, 2021		/s/ Elizabeth B. Higgins
		Elizabeth B. Higgins Executive Vice President and Chief Financial Officer (Principal Financial Officer)