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, 2018

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	**58-1211925**
(State or other jurisdiction of incorporation or organization)	(I.R.S. employer identification no.)
2100 East Exchange Place **Tucker, Georgia**	**30084-5336**
(Address of principal executive offices)	(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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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 definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):
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** ☒

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.**

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OGLETHORPE POWER CORPORATION
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2018

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, 2017 and under "Risk Factors" 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;
- decisions made by the Georgia Public Service Commission in the regulatory process related to the two additional units at Plant Vogtle;
- a decision by Georgia Power Company to cancel 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;
- 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 construction of 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 the Department of Energy's 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;
- 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;
- 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;
- 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;
- 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;
- litigation or legal and administrative proceedings and settlements;
- our members' ability to perform their obligations to us;
- our members' ability to offer their retail, 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;
- 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; and
- hazards customary to the electric industry and the possibility that we may not have adequate insurance to cover losses resulting from these hazards.

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
September 30, 2018 and December 31, 2017

	(dollars in thousands)	
	2018	2017
Assets		
Electric plant:		
In service	**$ 8,995,373**	$ 8,886,407
Less: Accumulated provision for depreciation	**(4,451,569)**	(4,302,332)
	4,543,804	4,584,075
Nuclear fuel, at amortized cost	**343,285**	358,562
Construction work in progress	**3,633,520**	2,935,868
Total electric plant	**8,520,609**	7,878,505
Investments and funds:		
Nuclear decommissioning trust fund	**460,974**	445,055
Investment in associated companies	**75,059**	74,981
Long-term investments	**165,806**	140,622
Restricted investments	**523,237**	653,585
Other	**23,590**	22,562
Total investments and funds	**1,248,666**	1,336,805
Current assets:		
Cash and cash equivalents	**717,914**	397,695
Restricted short-term investments	**232,010**	229,324
Receivables	**176,652**	156,781
Inventories, at average cost	**248,366**	266,219
Prepayments and other current assets	**10,170**	18,884
Total current assets	**1,385,112**	1,068,903
Deferred charges:		
Regulatory assets	**609,919**	585,084
Prepayments to Georgia Power	**31,256**	45,575
Other	**21,206**	13,267
Total deferred charges	**662,381**	643,926
Total assets	**$11,816,768**	$10,928,139

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

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
September 30, 2018 and December 31, 2017

	(dollars in thousands)	
	2018	2017
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 967,106**	$ 911,087
Long-term debt	**8,286,205**	7,927,562
Obligation under capital leases	**84,535**	87,192
Other	**21,077**	20,051
Total capitalization	**9,358,923**	8,945,892
Current liabilities:		
Long-term debt and capital leases due within one year	**559,686**	216,694
Short-term borrowings	**203,888**	190,626
Accounts payable	**195,743**	212,868
Accrued interest	**80,808**	79,510
Member power bill prepayments, current	**189,997**	6,171
Other current liabilities	**73,754**	55,136
Total current liabilities	**1,303,876**	761,005
Deferred credits and other liabilities:		
Asset retirement obligations	**758,592**	734,997
Member power bill prepayments, non-current	**87,250**	203,615
Regulatory liabilities	**272,427**	251,649
Other	**35,700**	30,981
Total deferred credits and other liabilities	**1,153,969**	1,221,242
Total equity and liabilities	**$11,816,768**	$10,928,139

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, 2018 and 2017

(dollars in thousands)

	Three Months		Nine Months	
	2018	2017	**2018**	2017
Operating revenues:				
Sales to Members	**$384,529**	$376,508	**$1,123,741**	$1,091,975
Sales to non-Members	**115**	148	**470**	220
Total operating revenues	**384,644**	376,656	**1,124,211**	1,092,195
Operating expenses:				
Fuel	**151,903**	143,767	**394,494**	366,405
Production	**95,971**	93,657	**299,134**	293,930
Depreciation and amortization	**56,936**	56,143	**170,565**	167,983
Purchased power	**15,381**	14,345	**46,030**	44,222
Accretion	**9,608**	9,224	**28,364**	27,333
Total operating expenses	**329,799**	317,136	**938,587**	899,873
Operating margin	**54,845**	59,520	**185,624**	192,322
Other income:				
Investment income	**15,242**	14,850	**43,925**	44,509
Other	**1,765**	627	**5,383**	1,908
Total other income	**17,007**	15,477	**49,308**	46,417
Interest charges:				
Interest expense	**92,492**	93,809	**273,987**	280,621
Allowance for debt funds used during construction	**(35,123)**	(33,517)	**(104,272)**	(99,953)
Amortization of debt discount and expense	**3,149**	3,150	**9,198**	9,386
Net interest charges	**60,518**	63,442	**178,913**	190,054
Net margin	**$ 11,334**	$ 11,555	**$ 56,019**	$ 48,685

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

Oglethorpe Power Corporation
Consolidated Statements of Comprehensive Margin (Unaudited)
For the Three and Nine Months Ended September 30, 2018 and 2017

	(dollars in thousands)			
	Three Months		Nine Months	
	2018	2017	**2018**	2017
Net margin	**$11,334**	$11,555	**$56,019**	$48,685
Other comprehensive margin:				
Unrealized gain on available-for-sale securities	**—**	56	**—**	18
Total comprehensive margin	**$11,334**	$11,611	**$56,019**	$48,703

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

Oglethorpe Power Corporation
Consolidated Statements of Patronage Capital and Membership Fees
and Accumulated Other Comprehensive Margin (Deficit) (Unaudited)
For the Nine Months Ended September 30, 2018 and 2017

(dollars in thousands)

	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Deficit	Total
Balance at December 31, 2016	$859,810	$(370)	$859,440
Components of comprehensive margin:			
Net margin	48,685	—	48,685
Unrealized loss on available-for-sale securities	—	18	18
Balance at September 30, 2017	$908,495	$(352)	$908,143
Balance at December 31, 2017	$911,087	$ —	$911,087
Components of comprehensive margin:			
Net margin	56,019	—	56,019
Balance at September 30, 2018	**$967,106**	**$ —**	**$967,106**

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, 2018 and 2017

	(dollars in thousands)	
	2018	2017
Cash flows from operating activities:		
Net margin	**$ 56,019**	$ 48,685
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**277,209**	279,898
Accretion cost	**28,364**	27,333
Amortization of deferred gains	**(1,341)**	(1,341)
Allowance for equity funds used during construction	**(708)**	(567)
Deferred outage costs	**(23,761)**	(32,777)
Loss (gain) on sale of investments	**3,886**	(16,478)
Regulatory deferral of costs associated with nuclear decommissioning	**(20,019)**	631
Other	**(4,564)**	(6,610)
Change in operating assets and liabilities:		
Receivables	**(14,580)**	(24,650)
Inventories	**16,209**	(3,395)
Prepayments and other current assets	**2,535**	1,949
Accounts payable	**(6,098)**	83,585
Accrued interest	**1,298**	(9,347)
Accrued taxes	**12,312**	7,249
Other current liabilities	**(11,743)**	(13,354)
Member power bill prepayments	**67,461**	20,935
Other	**10,866**	—
Total adjustments	**337,326**	313,061
Net cash provided by operating activities	**393,345**	361,746
Cash flows from investing activities:		
Property additions	**(852,225)**	(737,146)
Activity in nuclear decommissioning trust fund—Purchases	**(360,801)**	(329,248)
—Proceeds	**354,897**	323,840
Decrease (increase) in restricted investments	**127,662**	(43,484)
Activity in other long-term investments—Purchases	**(160,813)**	(45,246)
—Proceeds	**135,673**	27,196
Other	**8,331**	(12,780)
Net cash used in investing activities	**(747,276)**	(816,868)
Cash flows from financing activities:		
Long-term debt proceeds	**280,257**	4,517
Long-term debt payments	**(117,684)**	(240,417)
Increase in short-term borrowings, net	**505,397**	652,401
Other	**6,180**	14,395
Net cash provided by financing activities	**674,150**	430,896
Net increase (decrease) in cash and cash equivalents	**320,219**	(24,226)
Cash and cash equivalents at beginning of period	**397,695**	366,290
Cash and cash equivalents at end of period	**$ 717,914**	$ 342,064
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 166,134**	$ 187,798
Supplemental disclosure of non-cash investing and financing activities:		
Change in asset retirement obligations	**$ 2,404**	$ 2,189
Accrued property additions at end of period	**$ 144,372**	$ 82,524
Interest paid-in-kind	**$ 44,040**	$ 42,555

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 (SEC). 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, the results for the three-month and nine-month periods ended September 30, 2018 and 2017. Examples of estimates used include those related to our asset retirement obligations and revenue recognition. Estimates for our asset retirement obligations include items such as closure and post-closure cost estimates, timing of expenditures, escalation factors and discount rates. Estimates for revenue recognition include items 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. Certain prior year amounts have been reclassified to conform with current year presentation.

Pursuant to our adoption of Revenue from Contracts with Customers (Topic 606), we adjusted sales to members for the three and nine month periods ended September 30, 2017 in our Consolidated Statements of Revenues and Expenses to reflect a $9.25 million and $15.0 million refund liability, respectively. The refund liability represents the adjustment to our revenue that we assessed as of September 30, 2017, that would have been required to meet our 2017 annual revenue requirement.

These consolidated financial statements should be read in conjunction with the financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2017, as filed with the SEC. The results of operations for the three-month and nine-month periods ended September 30, 2018 are not necessarily indicative of results to be expected for the full year. 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 2017 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, 2018 and December 31, 2017.

		Fair Value Measurements at Reporting Date Using		
	September 30, 2018	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	**$157,382**	$157,382	$ —	$ —
International equity trust	**87,462**	—	87,462	—
Corporate bonds and debt	**59,134**	—	56,276	2,858
US Treasury securities	**35,578**	35,578	—	—
Mortgage backed securities	**58,788**	—	58,788	—
Domestic mutual funds	**52,994**	52,994	—	—
Municipal bonds	**283**	—	283	—
Federal agency securities	**6,832**	—	6,832	—
Non-US Gov't bonds & private placements	**1,119**	—	1,119	—
Other	**1,402**	1,402	—	—
Long-term investments:				
International equity trust	**19,776**	—	19,776	—
Corporate bonds and debt	**15,018**	—	13,535	1,483
US Treasury securities	**8,084**	8,084	—	—
Mortgage backed securities	**12,410**	—	12,410	—
Domestic mutual funds	**100,175**	100,175	—	—
Federal agency securities	**1,002**	—	1,002	—
Treasury STRIPS	**9,223**	—	9,223	—
Other	**118**	118	—	—
Natural gas swaps	**14,961**	—	14,961	—

		Fair Value Measurements at Reporting Date Using		
	December 31, 2017	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)
		(dollars in thousands)		
Nuclear decommissioning trust funds:				
Domestic equity	$142,419	$142,419	$ —	$—
International equity trust	88,820	—	88,820	—
Corporate bonds and debt	66,317	—	66,317	—
US Treasury securities	38,791	38,791	—	—
Mortgage backed securities	49,379	—	49,379	—
Domestic mutual funds	47,833	47,833	—	—
Municipal bonds	92	—	92	—
Federal agency securities	3,725	—	3,725	—
Other	7,679	7,679	—	—
Long-term investments:				
International equity trust	20,071	—	20,071	—
Corporate bonds and debt	16,215	—	16,215	—
US Treasury securities	6,670	6,670	—	—
Mortgage backed securities	7,267	—	7,267	—
Domestic mutual funds	87,011	87,011	—	—
Federal agency securities	259	—	259	—
Other	3,129	3,129	—	—
Natural gas swaps	6,328	—	6,328	—

The Level 2 investments above in corporate bonds and debt, federal agency mortgage backed 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. 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 following table presents the changes in Level 3 assets measured at fair value on a recurring basis during the three and nine months ended September 30, 2018.

	Three Months Ended September 30, 2018
	Corporate bonds and debt
	(dollars in thousands)
Balance at June 30, 2018	$4,997
Transfers from Level 3	—
Total gains or losses (realized/unrealized):	
Changes in net assets	(656)
Balance at September 30, 2018	$4,341

	Nine Months Ended September 30, 2018
	Corporate bonds and debt
	(dollars in thousands)
Balance at December 31, 2017	$ —
Transfers to Level 3	4,997
Total gains or losses (realized/unrealized):	
Changes in net assets	(656)
Balance at September 30, 2018	$4,341

None of our assets or liabilities measured at fair value on a recurring basis were categorized as Level 3 at December 31, 2017.

The estimated fair values of our long-term debt, including current maturities at September 30, 2018 and December 31, 2017 were as follows (in thousands):

	2018		2017	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
	(in thousands)			
Long-term debt	**$8,936,098**	**$9,235,718**	$8,232,703	$9,155,942

The estimated fair value of long-term debt is classified as Level 2 and is based on observed or quoted market prices for the same or similar issues, or based 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. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC). 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, 2018 plus an applicable spread, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank. The rates on the CFC debt are fixed and the valuation is based on rate quotes provided by CFC.

For cash, 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.* Our risk management and compliance committee provides general oversight over all risk management and compliance activities, including but not limited to, commodity trading, investment portfolio management and interest rate risk management. We use commodity trading derivatives to manage our exposure to fluctuations in the market price of natural gas. We apply regulatory operations accounting to all of our derivative instruments instead of hedge accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps are reflected as regulatory assets or liabilities, as appropriate.

We are exposed to credit risk as a result of entering into these hedging 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, 2018, 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 hedge 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.

Gas hedges. 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, 2018 and December 31, 2017, the estimated fair value of our natural gas contracts was a net liability of approximately $14,961,000 and $6,328,000, respectively.

As of September 30, 2018 and December 31, 2017, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2018 due to our credit rating being downgraded below investment grade, we would have been required to post collateral or letters of credit of $14,961,000 with our counterparties.

The following table reflects the notional volume of our natural gas derivatives as of September 30, 2018 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2018	4.1
2019	21.9
2020	19.6
2021	17.1
2022	11.5
2023	1.4
Total	**75.6**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at September 30, 2018 and December 31, 2017.

	Balance Sheet Location	Fair Value	
		2018	2017
		(dollars in thousands)	
Assets:			
Natural gas swaps	Other current assets	**$ 290**	$ 412
Liabilities:			
Natural gas swaps	Other current liabilities	**$ 2,440**	$1,575
Natural gas swaps	Other deferred credits	**$12,811**	$5,165

The following table presents the gross realized gains and (losses) on derivative instruments recognized in margin for the three and nine months ended September 30, 2018 and 2017.

	Statement of Revenues and Expenses Location	Three months ended September 30,		Nine months ended September 30,	
		2018	2017	**2018**	2017
		(dollars in thousands)			
Natural Gas Swaps	Fuel	**$863**	$ 778	**$2,614**	$ 3,514
Natural Gas Swaps	Fuel	**(97)**	(678)	**(956)**	(1,495)
Total		**$766**	$ 100	**$1,658**	$ 2,019

The following table presents the net unrealized losses on derivative instruments deferred on the balance sheet at September 30, 2018 and December 31, 2017.

	Balance Sheet Location	2018	2017
		(dollars in thousands)	
Natural gas swaps	Regulatory asset	**$(14,961)**	$(6,328)
Total		**$(14,961)**	$(6,328)

(D) *Investments in Debt and Equity Securities.* Investment securities we hold are carried at market value. Prior to October 1, 2017, unrealized gains and losses of investment securities related to nuclear decommissioning were deferred pursuant to regulated operations accounting, while those of all other investment securities were recorded to accumulated other comprehensive (deficit) margin. During the fourth quarter of 2017, we began applying 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. As of September 30, 2018, approximately 55% of these gross unrealized losses with a fair value totaling $47,209,000 million had been unrealized for a duration of greater than one year, while the remaining gross unrealized losses with a fair value of $209,318,000 had been unrealized for a duration of less than one year.

The following tables summarize debt and equity securities as of September 30, 2018 and December 31, 2017.

		Gross Unrealized (dollars in thousands)		
September 30, 2018	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$249,762**	**$111,570**	**$ (4,682)**	**$356,650**
Debt	**274,110**	**573**	**(6,073)**	**268,610**
Other	**1,520**	**—**	**—**	**1,520**
Total	**$525,392**	**$112,143**	**$(10,755)**	**$626,780**

		Gross Unrealized (dollars in thousands)		
December 31, 2017	Cost	Gains	Losses	Fair Value
Equity	$246,549	$91,954	$(4,064)	$334,439
Debt	240,878	1,814	(2,262)	240,430
Other	10,807	1	—	10,808
Total	$498,234	$93,769	$(6,326)	$585,677

(E) *Recently Issued or Adopted Accounting Pronouncements.* In May 2014, the Financial Accounting Standards Board (FASB) issued "Revenue from Contracts with Customers" (Topic 606). The new revenue standard requires that an entity recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. In addition, Topic 606 requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers.

We adopted the new revenue standard effective January 1, 2018, using the full retrospective method, which required us to restate each prior reporting period presented. The adoption of the new revenue standard did not change the nature, amounts or timing of revenues we recognize within an annual reporting period. The most significant impact of the new revenue standard to us relates to the potential recognition of refund liabilities related to capacity revenues in interim reporting periods. Refund liabilities, if any, are included in accounts payable on our consolidated balance sheets. At September 30, 2018 and 2017, we recognized refund liabilities totaling $20,000,000 and $15,000,000, respectively. Adoption of the new revenue standard had no impact to cash from or used in operating, financing, or investing on our consolidated cash flows statements.

In January 2016, the FASB issued "Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities." The amendments in this update address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. The new standard is effective for us for annual reporting periods beginning after December 15, 2017, and interim periods therein. Certain provisions within this update can be adopted early. Certain provisions within this update should be applied by means of a cumulative effect adjustment to the balance sheet of the fiscal year of adoption and certain provisions should be applied prospectively. One of the provisions in this standard requires our equity investments, except those accounted for under the equity method of accounting or those that result in consolidation of our subsidiary, to be measured at fair value with changes in fair value recognized in net income. None of the other provisions in this standard will have any impact to our consolidated financial statements. During the fourth quarter, we adopted regulatory accounting treatment with respect to unrealized gains and/or losses on our equity investments. Upon applying regulatory accounting treatment, unrealized gains on our equity investments will be recorded as a regulatory liability and, conversely, unrealized losses on our equity investments will be recorded as a regulatory asset, at the end of each reporting period. As of December 31, 2017, we recorded $618,000 of unrealized losses on our equity investments as a regulatory asset. On January 1, 2018, we adopted the amendments within this standard. The adoption of this standard did not have any impact to our consolidated financial statements due to our regulatory accounting treatment for unrealized gains and/or losses on our equity investments.

In February 2016, the FASB issued "Leases (Topic 842)." The new leases standard requires a dual approach for lessee accounting under which a lessee would account for leases as finance leases or operating leases. Both finance leases and operating leases will result in the lessee recognizing a right-of-use (ROU) asset and a corresponding lease liability. For finance leases the lessee would recognize interest expense and amortization of the ROU asset and for operating leases the lessee would recognize a straight-line total lease expense. Quantitative and qualitative disclosures will also be required surrounding significant judgments made by management. The new lease standard does not substantially change lessor accounting. The new leases standard is effective for us on a modified retrospective approach for annual reporting periods beginning after December 15, 2018, and interim periods therein. Early adoption is permitted.

In January 2018, the FASB issued "Land Easement Practical Expedient for Transition to Topic 842" that allows an entity to not evaluate existing and expired land easements that were not previously accounted for as leases upon adoption of Topic 842. Any land easements entered into prospectively or modified after adoption should be evaluated to assess whether they meet the definition of a lease.

In July 2018, the FASB issued "Codification Improvements to Topic 842, Leases" to clarify certain narrow aspects of the guidance in Topic 842. The effective date and transition requirements in this standard are the same as the requirements in Topic 842. We are currently assessing the potential impacts of the amendments in this standard in context of the overall adoption of the new accounting guidance for leases. In addition, we continue to monitor both the FASB's ongoing standard-setting activities that may result in the issuance of additional targeted improvements, as well as potential industry implementation issues.

In July 2018, the FASB issued "Leases (Topic 842): Targeted Improvements" to add a new transition method to the new leases standard that allows entities to not apply the new guidance in the comparative periods entities present in their financial statements in the year of adoption. The FASB also provided a practical expedient that gives lessors an option to combine non-lease and associated lease components when certain criteria are met and requires a lessor to account for the combined component in accordance with the new revenue standard if the associated non-lease components are the predominant component.

While we have not fully completed our implementation of the new leases standard, we expect that the adoption of the standard will not have a material impact on our consolidated financial statements. We have a relatively small portfolio of leases with the most significant being our 60% undivided interest in Scherer Unit No. 2, railcar leases for the transportation of coal and various nominal leases.

We account for the Scherer Unit No. 2 leases as capital leases and the railcar leases as operating leases under the current lease accounting model. We believe that the key changes in adopting the new leases standard will be how we account for our operating leases that are currently off-balance sheet. Our evaluation process included, but was not limited to, reviewing all forms of leases, performing a completeness assessment over the lease population and analyzing the practical expedients available to us.

We will adopt the new leases standard on January 1, 2019, using the optional transition method to apply the new lease guidance as of January 1, 2019, rather than as of the earliest period presented.

In June 2016, the FASB issued "Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." The amendments in this update replace the current incurred loss impairment methodology with a methodology that reflects expected credit losses. The new standard is effective for us prospectively for annual reporting periods beginning after December 15, 2019, and interim periods therein. Early adoption is permitted. We are currently evaluating the future impact of this standard on our consolidated financial statements.

In March 2018, the FASB issued "Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118." In accordance with the standard, we recognized the provisional tax impacts related to the re-measurement of our deferred income tax assets and liabilities as of the year ended December 31, 2017. As of September 30, 2018, we have not made any additional measurement-period adjustments related to these items. Such adjustments may be necessary in future periods due to, among other things, the significant complexity of the Tax Cuts and Job Act signed into law in December 2017, and anticipated additional regulatory guidance that may be issued by the Internal Revenue Service, changes in analysis, interpretations and assumptions we made and actions we may take as a result of the Act. We are continuing to gather information to assess the application of the Act and expect to complete our analysis during the fourth quarter of 2018. We do not expect any net impact to the results of operations.

In August 2018, the FASB issued "Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement." This standard eliminates, adds and modifies certain disclosure requirements for fair value measurements as part of the FASB's disclosure framework project. Entities will no longer be required to disclose the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy, the policy for timing of transfers between levels and the valuation processes for Level 3 fair value measurements. However, public business entities will be required to disclose the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. The amendments in this update are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. An entity is permitted to early adopt any removed or modified disclosures upon issuance of this update and delay adoption of the additional disclosures until their effective date.

As the standard relates only to disclosures, we do not expect the adoption of this standard to have a material impact on our consolidated financial statements. We are currently evaluating the standard and whether we will early adopt the standard.

(F) *Revenue Recognition.* As an electric membership cooperative, our principle 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 through December 30, 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. While not significant, 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 their 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 between us and each of our members. 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 agreed to by us in the applicable agreement. Margins produced from non-member sales are included in our rate schedule formula and reduce revenue requirements from our members.

The standard selling price at which we provide capacity services to our members is determined by our formulary rate on an annual basis. As a result, the consideration we receive for providing capacity services is determined annually. Over the course of a year, our member capacity revenues are relatively stable. Capacity revenues may fluctuate year to year largely due to the recovery of fixed operation and maintenance costs. 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. 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. For information regarding regulatory accounting, see Note I.

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 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 significant 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 J.

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. We do not provide all of our members' energy requirements. 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 2018, our board has approved a targeted margins for interest ratio of 1.14 and for 2017, we achieved a 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 if a refund to our members of excess consideration is likely. If required, 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, 2018 and 2017, we recognized refund liabilities totaling $20,000,000 and $15,000,000, respectively. In September 2017, our board of directors approved a budget adjustment that reduced revenue requirements by $5,000,000, which was previously reflected in the three and nine-month periods ended September 30, 2017. Based on our current agreements with non-members, we do not refund any consideration received from non-members.

Sales to members were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	(dollars in thousands)			
	2018	2017	**2018**	2017
Capacity revenues	**$219,597**	$220,347	**$ 691,649**	$ 687,725
Energy revenues	**164,932**	156,161	**432,092**	404,250
Total	**$384,529**	$376,508	**$1,123,741**	$1,091,975

Sales to non-members during the three and nine months ended September 30, 2018 and September 30, 2017 were insignificant.

We bill our members for capacity and energy on a monthly basis. Based on the payment terms of the wholesale power contracts and power purchase and sale agreements, we receive payment during the following month in which capacity and energy revenues are billed. Estimated energy charges are billed to members based on the amount of energy supplied during the month and are adjusted when actual costs are available, generally the following month. As payment is due to us within one month of billing, we do not provide significant financing to our customers.

The opening and closing balances of receivables from contracts with our customers are as follows:

	(dollars in thousands)			
	September 30, 2018	September 30, 2017	December 31, 2017	December 31, 2016
Receivables from members	**$140,010**	$124,858	$126,211	$136,552

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.

For the three and nine months ended September 30, 2018 and September 30, 2017, no impairment losses were recognized on any receivables that arose from contracts with our customers.

(G) *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.

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.

The ultimate impact of any environmental regulations is uncertain and could have an effect on our financial condition, results of operations and cash flows as a result of 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.

(H) *Restricted Investments.* 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 funds on deposit earn interest at a rate of 5% per annum. At September 30, 2018 and December 31, 2017, we had restricted investments totaling $755,248,000 and $882,909,000, respectively, of which $523,237,000 and $653,585,000, respectively, were classified as long-term. The funds on deposit with the Rural Utilities Service in the Cushion of Credit Account are held by the U.S. Treasury, acting through the Federal Financing Bank.

(I) *Regulatory Assets and Liabilities.* We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery from our members in future revenues through rates under the wholesale power contracts we have with each of our members. Regulatory liabilities represent certain items of income that we have deferred 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 as of September 30, 2018 and December 31, 2017.

	2018	2017
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt[(a)]	**$ 47,981**	$ 52,989
Amortization on capital leases[(b)]	**34,650**	33,846
Outage costs[(c)]	**37,080**	40,525
Asset retirement obligations—Ashpond and other[(k)]	**93,842**	68,289
Depreciation expense[(d)]	**41,600**	42,667
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs[(e)]	**50,888**	48,702
Interest rate options cost[(f)]	**115,734**	112,102
Deferral of effects on net margin—Smith Energy Facility[(g)]	**161,995**	166,454
Other regulatory assets[(l)]	**26,149**	19,510
Total Regulatory Assets	**$609,919**	$585,084
Regulatory Liabilities:		
Accumulated retirement costs for other obligations[(h)]	**$ 16,499**	$ 12,813
Deferral of effects on net margin—Hawk Road Energy Facility[(g)]	**19,094**	19,553
Major maintenance reserve[(i)]	**53,587**	47,087
Amortization on capital leases[(b)]	**17,880**	20,055
Deferred debt service adder[(j)]	**102,819**	95,695
Asset retirement obligations—Nuclear[(k)]	**49,210**	53,571
Other regulatory liabilities[(l)]	**13,338**	2,875
Total Regulatory Liabilities	**$272,427**	$251,649
Net Regulatory Assets	**$337,492**	$333,435

(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 26 years.

(b) Represents the difference between expense recognized for rate-making purposes and financial statement purposes related to capital 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 48 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 cycle 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) Deferred charges related to Vogtle Units No. 3 and No. 4 training and interest related 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.

(f) Deferral of premiums paid to purchase interest rate options 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 in February 2020 and will be amortized through February 2044, the life of the DOE-guaranteed loan which is financing a portion of the construction project.

(g) 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.

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

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

(j) 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.

(k) Represents difference in timing of recognition of the costs for decommissioning and ashpond remediation for financial statement purposes and for ratemaking purposes.

(l) The amortization periods for other regulatory assets range up to 32 years and the amortization periods of other regulatory liabilities range up to 9 years.

(J) *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 January 2023, with the majority of the balance scheduled to be credited by the end of 2019.

(K) *Debt.*

a) *Department of Energy Loan Guarantee:*

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (the Title XVII Loan Guarantee Program), 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 (as amended, the Loan Guarantee Agreement) pursuant to which the Department of Energy agreed to guarantee our obligations under the Note Purchase Agreement dated as of February 20, 2014 (the 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 (the FFB Notes and together with the Note Purchase Agreement, the FFB Credit Facility Documents). The FFB Credit Facility 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 received 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. Aggregate borrowings under the Facility may not exceed $3,057,069,461, of which $335,471,604 is designated for capitalized interest.

Under the Loan Guarantee Agreement, we are obligated to reimburse the Department of Energy in the event the Department of Energy is required to make any payments to the Federal Financing Bank under the 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 notes and 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 will begin on February 20, 2020. Under both FFB Notes, the interest rates 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%.

At September 30, 2018, aggregate Department of Energy-guaranteed borrowings totaled $1,779,626,000, including capitalized interest.

Pursuant to the amended terms of the Loan Guarantee Agreement, no further advances are permitted pending satisfaction of certain conditions, including an amendment to the Loan Guarantee Agreement. When these conditions are satisfied, advances may be requested under the Facility on a quarterly basis through December 31, 2020.

In addition to the conditions described above, future advances are subject to satisfaction of customary conditions, including certification of compliance with the requirements of the Title XVII Loan Guarantee Program, accuracy of project-related representations and warranties, delivery of updated project-related information, our continued ownership of our interest in Vogtle Units No. 3 and No. 4 free and clear of any liens except those permitted under the Loan Guarantee Agreement, evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act, as amended, and certification from the Department of Energy's consulting engineer that proceeds of the advance are used to reimburse eligible project costs.

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.

Under the Loan Guarantee Agreement, upon the occurrence of an "Alternate Amortization Event," the Department of Energy may require us to prepay the outstanding principal amount of all guaranteed borrowings over a period of five years, with level principal amortization. These events include (i) cessation of the construction of Vogtle Units No. 3 and No. 4 for twelve consecutive months, (ii) termination of the Services Agreement as defined in Note L or rejection of the Services Agreement in bankruptcy if Georgia Power does not maintain access to certain related intellectual property rights, (iii) a decision by us not to continue construction of Vogtle Units No. 3 and No. 4, (iv) loss of or failure to receive necessary regulatory approvals under certain circumstances, (v) loss of access to intellectual property rights necessary to construct or operate Vogtle Units No. 3 and No. 4 under certain circumstances, (vi) our failure to fund our share of operation and maintenance expenses for Vogtle Units No. 3 and No. 4 for twelve consecutive months, (vii) change of control of Oglethorpe and (viii) 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. We may also voluntarily prepay outstanding borrowings under the Facility. Under the FFB Credit Facility Documents, any prepayment will be subject to a make-whole premium or discount, as applicable.

On September 28, 2017, the Department of Energy issued a conditional commitment to us for up to $1,619,679,706 of additional guaranteed funding under the Loan Guarantee Agreement. This conditional commitment expires on March 31, 2019. Final approval and issuance of this additional loan guarantee by the Department of Energy cannot be assured and is subject to negotiation of definitive agreements, completion of due diligence by the Department of Energy, receipt of any necessary regulatory approvals and satisfaction of other conditions.

b) *Rural Utilities Service Guaranteed Loans:*

For the nine-month period ended September 30, 2018, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $280,257,000 for long-term financing of general and environmental improvements at existing plants.

In October 2018, we received an additional $32,771,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for long-term financing of general and environmental improvements at existing plants.

These advances are secured under our first mortgage indenture.

c) *Pollution Control Revenue Bonds:*

On December 28, 2017, the Development Authority of Burke County (Georgia) issued, on our behalf, $399,785,000 (Series 2017C, D, E, F Burke) in aggregate principal amount of tax-exempt pollution control revenue bonds to refinance costs associated with certain of our pollution control facilities. The bonds were directly purchased by two banks and the proceeds defeased our obligations under $399,785,000 of pollution control revenue bonds issued in 2008 that were callable on or after January 1, 2018. Those 2008 bonds were fully redeemed on their call date. Each series of the 2017 bonds bore interest at an indexed variable rate until February 1, 2018 when we converted the bonds into fixed interest rate modes. We converted the (i) $200,000,000

Series 2017C and Series 2017D bonds to a fixed rate of 4.125% per annum to maturity with an optional call at par on February 1, 2028, (ii) $100,000,000 Series 2017E bonds to a fixed term rate of 3.25% per annum to the mandatory tender date of February 3, 2025 and (iii) $99,785,000 Series 2017F bonds to a fixed term rate of 3.00% per annum to the mandatory tender date of February 1, 2023. The Series 2017C, D, E, F bonds are scheduled to mature in 2041 through 2045. Our payment obligations related to these bonds are secured under our first mortgage indenture.

d) *First Mortgage Bonds:*

On October 30, 2018, we issued $500,000,000 of 5.05% first mortgage bonds, Series 2018A, for the purpose of providing long-term financing for expenditures related to the construction of Vogtle Units No. 3 and No.4. In conjunction with the issuance of the bonds, we repaid $492,135,000 of outstanding commercial paper, which was classified as long-term debt at September 30, 2018. The bonds are due to mature October 2048 and are secured under our first mortgage indenture.

(L) *Vogtle Units No. 3 and No. 4 Construction Project.* We, Georgia Power, the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units 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. In connection with the bankruptcy filing, Georgia Power, acting for itself and as agent for the other Co-owners, entered into an Interim Assessment Agreement with Westinghouse and WECTEC Staffing Services LLC to provide for a continuation of work at Vogtle Units No. 3 and No. 4. The Interim Assessment Agreement expired upon the effective date of the Services Agreement.

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 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.

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 amended, the Joint Ownership Agreements). Certain provisions of the Joint Ownership Agreements were modified further on September 26, 2018 by the Term Sheet described below.

On December 21, 2017, the Georgia Public Service Commission took a series of actions related to the construction of Vogtle Units No. 3 and No. 4 and issued its related order on January 11, 2018. Among other actions, the Public Service Commission (i) accepted Georgia Power's recommendation to continue construction of Vogtle Units No. 3 and No. 4, with Southern Nuclear serving as construction manager and Bechtel as primary contractor and (ii) approved the revised schedule placing Unit No. 3 in service in November 2021 and Unit No. 4 in service in November 2022. In its January 11, 2018 order, the Public Service Commission stated if certain conditions change and assumptions upon which Georgia Power's seventeenth Vogtle construction monitoring (VCM) report are based do not materialize, the Public Service Commission reserved the right to reconsider the decision to continue construction. Parties have filed two petitions with the Fulton County Superior Court appealing the Georgia Public Service Commission's January 11, 2018 order. Georgia Power has stated that it believes these appeals have no merit; however, an adverse outcome in either appeal combined with subsequent adverse action by the Public Service Commission could have a material impact on our financial condition and results of operations.

Earlier in 2018, Georgia Power advised us that it became aware that the estimated future Vogtle project costs were projected to exceed the corresponding budgeted amounts included in its seventeenth VCM report. Upon discovery of these variances, the Co-owners requested Southern Nuclear perform a full cost analysis and reforecast the cost to complete the project and engaged a third party to independently assess this analysis, forecast, and existing project controls for identifying budget variances. Following this analysis, Georgia Power proposed an increased construction budget and included a revised estimate to complete in its nineteenth VCM report filed with the Georgia Public Service Commission in August 2018. This revised estimate included an approximate $1.5 billion increase in capital costs (our 30% share is approximately $450 million) and a project-level contingency in an amount of $800 million (our 30% share is $240 million). The increase in the revised budget is primarily attributable to Bechtel and subcontractor construction costs, including craft labor incentives, as well as expenses for project management, oversight and support. The scheduled in-service dates of November 2021 and November 2022 for Vogtle Units No. 3 and No. 4, respectively, did not change in connection with these budget revisions.

Further, Georgia Power informed the Public Service Commission in its nineteenth VCM report that it did not intend to seek rate recovery for its proportionate share of the additional capital costs identified in that report. As a result of Georgia Power's decision not to seek rate recovery of its allocation of these costs and the increased construction budget, 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 voted to continue construction of Vogtle Units No. 3 and No. 4. In connection with our vote to continue construction with Vogtle Units No. 3 and No. 4, we approved a revised budget of $7.5 billion for our 30% ownership interest. The impact of the additional project costs on our budget was substantially mitigated by nearly $500 million of contingency included in our prior budget. As with our prior budgets and consistent with our conservative budget practices, our revised budget includes a separate Oglethorpe-level contingency amount in addition to capital costs, allowance for funds used during construction, and our allocation of the project-level contingency. As of September 30, 2018, our total investment in the additional Vogtle units was $3,621,928,000.

In connection with the 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). We are working with the other Co-owners to clarify any interpretive issues related to the operation of certain provisions of the Term Sheet. Pursuant to the Term Sheet:

- each Co-owner will be 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 forms 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, 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);
- Georgia Power will be responsible for 65.7% of construction costs, subject to exceptions, 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 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 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(s) to be conveyed from the tendering Co-owner to Georgia Power would 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 would 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.

In the event the actual costs at completion of a unit are less than the EAC reflected in the nineteenth VCM report and (i) Vogtle Unit No. 3 is placed in service by the currently scheduled date of November 2021 or (ii) Vogtle Unit No. 4 is placed in service by the currently scheduled date of November 2022, Georgia Power would be entitled to 60.7% of the cost savings with respect to the relevant unit and the remaining Co-owners would be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

Pursuant to the Term Sheet, the Co-owners will continue to retain a third party to independently consult, advise and report to the Co-owners on issues pertaining to (i) project management and controls, (ii) organizational controls, (iii) commercial management plans and (iv) interim project reports until released by 67% of the Co-owners.

Pursuant to the Joint Ownership Agreements, as amended by the Term Sheet, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Term Sheet provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more over the most recently approved schedule. In addition, pursuant to the Joint Ownership Agreements, the required approval of holders of ownership interests in Vogtle Units No. 3 and No. 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement.

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

Subsequent to Westinghouse's bankruptcy filing, a number of subcontractors to Westinghouse alleged non-payment by Westinghouse for amounts owed for work performed on Vogtle Units No. 3 and No. 4. Georgia Power, acting for itself and as agent for the Co-owners, has taken actions to remove liens on the site filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against Westinghouse and the Co-owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and payment of other Westinghouse pre-petition accounts payable have been paid or accrued as of September 30, 2018.

We have a $3,057,069,461 federal loan guarantee from the Department of Energy, under which we have borrowed $1,779,626,000 as of September 30, 2018. Pursuant to the terms of the loan guarantee agreement, no further advances are permitted pending satisfaction of certain conditions. On September 28, 2017, the Department of Energy issued a conditional commitment to us for up to $1,619,679,706 of additional guaranteed funding under the loan guarantee agreement. The Department of Energy has extended the expiration date for this conditional commitment to March 31, 2019. Final approval and issuance of the additional loan guarantee by the Department of Energy cannot be assured and is subject to an amendment and restatement of the loan guarantee agreement and satisfaction of other conditions. For additional information regarding conditions for future advances, potential repayment over a five-year period, covenants and events of default under the loan guarantee agreement with the Department of Energy, see Note K.

We have also financed $1,887,000,000 of the capital costs of the Vogtle units through capital market debt issuances which includes the October 2018 bond issue described in Note K. We anticipate financing any project costs not financed with Department of Energy in the capital markets. The timing and availability of funds under the Department of Energy loan guarantee will influence our decisions as to the timing of any capital markets offerings.

In a filing with the Public Service Commission supporting the nineteenth VCM report, Georgia Power reported that, as of August 2018, overall construction on the Vogtle project was more than 55% complete and that the total project (which includes engineering, procurement, construction and other project phases) was over 70% complete. As construction continues, risks remain that construction-related challenges, including management of contractors, subcontractors, and vendors labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly and/or installation, including any required engineering changes, of plant systems, structures and components, or other issues could further impact the projected schedule and cost. Monthly construction production targets required to maintain the current project schedule continue to increase significantly through the remainder of 2018 and into 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed. Aspects of the Westinghouse AP1000 design are based on new technologies that only recently began commercial operation in the global nuclear industry at this scale.

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 assure 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. As a result of such compliance processes, 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 resolution of inspections, tests, analyses, and acceptance criteria and the related approvals by the Nuclear Regulatory Commission, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

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

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.

Results of Operations

For the Nine Months Ended September 30, 2018 and 2017

Net Margin

Our net margins for the three and nine-month periods ended September 30, 2018 were $11.3 million and $56.0 million, respectively, compared to $11.6 million and $48.7 million for the same periods of 2017. Through September 30, 2018, we recognized approximately 109% of our targeted net margin of $51.2 million for the year ending December 31, 2018. 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 2018 targeted margins for interest ratio of 1.14. Pursuant to our adoption of Revenue from Contracts with Customers (Topic 606), we assessed the annual revenue requirement to meet the targeted margins for interest ratio and recorded refund liabilities of $14.3 million and $20.0 million for the three and nine month periods ended September 30, 2018, respectively. In addition, our 2017 revenues for the three and nine-month periods have been adjusted to reflect a $9.2 million and $15.0 million refund liability as of September 30, 2017. In September 2017, our board of directors approved a budget adjustment that reduced revenue requirements by $5.0 million, which was previously reflected in the three and nine-month periods ended September 30, 2017. 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 2017 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 and nine-month periods ended September 30, 2018 and 2017 were as follows:

	Three Months Ended September 30, (dollars in thousands) 2018	2017	2018 vs. 2017 % Change	Nine Months Ended September 30, (dollars in thousands) 2018	2017	2018 vs. 2017 % Change
Capacity revenues	**$ 219,597**	$ 220,347	(0.3%)	**$ 691,649**	$ 687,725	0.6%
Energy revenues	**164,932**	156,161	5.6%	**432,092**	404,250	6.9%
Total	**$ 384,529**	$ 376,508	2.1%	**$ 1,123,741**	$ 1,091,975	2.9%
MWh Sales to members	**6,757,386**	6,962,978	(3.0%)	**17,784,450**	18,213,379	(2.4%)
Cents/kWh	**5.69**	5.41	5.2%	**6.32**	6.00	5.4%
Member energy requirements supplied	**57%**	62%	(8.1%)	**58%**	63%	(8.7%)

Energy revenues from members increased for the three and nine-month periods ended September 30, 2018 compared to September 30, 2017 primarily due to the recovery of fuel costs. Megawatt-hour sales to members for the three and nine-month periods ended September 30, 2018 compared to the same periods in 2017 decreased largely due to unplanned outages. For a discussion of fuel cost, which is the primary component of energy revenues, and generation, see "—*Operating Expenses*."

Operating Expenses

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

	Cost (dollars in thousands)			Generation (MWh)			Cents per kWh		
	Three Months Ended September 30,			Three Months Ended September 30,			Three Months Ended September 30,		
Fuel Source	2018	2017	2018 vs. 2017 % Change	2018	2017	2018 vs. 2017 % Change	2018	2017	2018 vs. 2017 % Change
Coal	**$ 39,001**	$ 30,924	26.1%	**1,360,086**	1,157,960	17.5%	**2.87**	2.67	7.4%
Nuclear	**21,525**	23,249	(7.4%)	**2,558,186**	2,585,668	(1.1%)	**0.84**	0.90	(6.4%)
Gas:									
Combined Cycle	**60,411**	67,058	(9.9%)	**2,249,233**	2,888,612	(22.1%)	**2.69**	2.32	15.7%
Combustion Turbine	**30,966**	22,536	37.4%	**787,768**	544,294	44.7%	**3.93**	4.14	(5.1%)
	$151,903	$143,767	5.7%	**6,955,273**	7,176,534	(3.1%)	**2.18**	2.00	9.0%

	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	2018	2017	2018 vs. 2017 % Change	2018	2017	2018 vs. 2017 % Change	2018	2017	2018 vs. 2017 % Change
Coal	**$ 88,563**	$ 81,867	8.2%	**2,999,117**	2,913,161	3.0%	**2.95**	2.81	5.1%
Nuclear	**64,007**	66,538	(3.8%)	**7,640,520**	7,399,354	3.3%	**0.84**	0.90	(6.8%)
Gas:									
Combined Cycle	**189,741**	181,254	4.7%	**6,538,930**	7,546,775	(13.4%)	**2.90**	2.40	20.8%
Combustion Turbine	**52,183**	36,746	42.0%	**1,142,252**	881,514	29.6%	**4.57**	4.17	9.6%
	$394,494	$366,405	7.7%	**18,320,819**	18,740,804	(2.2%)	**2.15**	1.96	10.1%

Total fuel costs increased for the three and nine-month periods ended September 30, 2018 compared to the same periods of 2017 primarily due to (i) increased transportation costs associated with a new pipeline placed into service in August 2017 and (ii) a shift in generation to relatively more expensive units. This shift in generation was primarily driven by unplanned outages at one of our coal-fired units in the first quarter of 2018 and at one of our natural gas-fired combined cycle units during the third quarter of 2018. These outages also contributed to decreased generation during these periods as members procured a larger percentage of their energy requirements from other sources. The nine-month period increase was also impacted by higher natural gas prices, particularly during January when extreme cold weather affected the supply and transportation of natural gas. In addition to the natural gas consumed being more expensive, the higher cost contributed to a shift in generation to oil and coal-fired units.

Financial Condition

Balance Sheet Analysis as of September 30, 2018

Assets

Cash used for property additions for the nine-month period ended September 30, 2018 totaled $852.2 million. Of this amount, $673.2 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, $77.5 million related to environmental control projects at our coal-fired plants and $47.0 million was for nuclear fuel purchases. The remainder was for expenditures related to normal additions and replacements to our existing generation facilities.

At September 30, 2018, restricted investments totaled $755.2 million. These investments consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. The funds, including interest earned thereon, can only be applied to debt service on our Rural Utilities Service-guaranteed Federal Financing Bank notes. Decisions regarding when to apply the funds are influenced by the interest rate environment and our anticipated liquidity needs.

Equity and Liabilities

Long-term debt increased $358.6 million during the nine-month period ended September 30, 2018 primarily as a result of $324.3 million in advances on existing Rural Utilities Service loans, capitalized interest related to the Department of Energy loan and $492.1 million of commercial paper classified as long-term at September 30, 2018 that was repaid utilizing proceeds from Series 2018A first mortgage bonds issued on October 30, 2018. Offsetting the increase were current maturities of long-term debt, including $350 million in first mortgage bonds which mature in March 2019. For information regarding Rural Utilities Service advances, the Department of Energy Loan guarantee and the Series 2018A first mortgage bonds, see Note K of Notes to Unaudited Consolidated Financial Statements.

Long-term debt and capital leases due within one year increased $343.0 million primarily due to $350 million of first mortgage bonds maturing in March 2019 that were classified as current debt during the period.

Member power bill prepayments represent funds received from our members for the prepayment of their monthly power bills. At September 30, 2018, $190.0 million of the member power bill prepayments was classified as a current liability and $87.2 million was classified as a long-term liability. During the nine months ended September 30, 2018, $70.8 million of prepayments were received from the members and $187.1 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note J of Notes to Unaudited Consolidated Financial Statements.

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4

We, Georgia Power Company, the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia, acting by and through its Board of Water, Light and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, the Co-owners) are parties to an Ownership Participation Agreement that, along with other agreements, governs our participation in two additional nuclear units at Plant Vogtle, Units No. 3 and No. 4. The Co-owners appointed Georgia Power to act as agent under this agreement. 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. In connection with the bankruptcy filing, Georgia Power, acting for itself and as agent for the other Co-owners, entered into an Interim Assessment Agreement with Westinghouse and WECTEC Staffing Services LLC to provide for a continuation of work at Vogtle Units No. 3 and No. 4. The Interim Assessment Agreement expired upon the effective date of the Services Agreement.

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 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.

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 amended, the Joint Ownership Agreements). Certain provisions of the Joint Ownership Agreements were modified further on September 26, 2018 by the Term Sheet described below.

On December 21, 2017, the Georgia Public Service Commission took a series of actions related to the construction of Vogtle Units No. 3 and No. 4 and issued its related order on January 11, 2018. Among other actions, the Public Service Commission (i) accepted Georgia Power's recommendation to continue construction of Vogtle Units No. 3 and No. 4, with Southern Nuclear serving as construction manager and Bechtel as primary contractor and (ii) approved the revised schedule placing Unit No. 3 in service in November 2021 and Unit No. 4 in service in November 2022. In its January 11, 2018 order, the Public Service Commission stated if certain conditions change and assumptions upon which Georgia Power's seventeenth Vogtle construction monitoring (VCM) report are based do not materialize, the Public Service Commission reserved the right to reconsider the decision to continue construction. Parties have filed two petitions with the Fulton County Superior Court appealing the Georgia Public Service Commission's January 11, 2018 order. Georgia Power has stated that it believes these appeals have no merit; however, an adverse outcome in either appeal combined with subsequent adverse action by the Public Service Commission could have a material impact on our financial condition and results of operations.

Earlier in 2018, Georgia Power advised us that it became aware that the estimated future Vogtle project costs were projected to exceed the corresponding budgeted amounts included in its seventeenth VCM report. Upon discovery of these variances, the Co-owners requested Southern Nuclear perform a full cost analysis and reforecast the cost to complete the project and engaged a third party to independently assess this analysis, forecast, and existing project controls for identifying budget variances. Following this analysis, Georgia Power proposed an increased construction budget and included a revised estimate to complete in its nineteenth VCM report filed with the Georgia Public Service Commission in August 2018. This revised estimate included an approximate $1.5 billion increase in capital costs (our 30% share is approximately $450 million) and a project-level contingency in an amount of $800 million (our 30% share is $240 million). The increase in the revised budget is primarily attributable to Bechtel and subcontractor construction costs, including craft labor incentives, as well as expenses for project management, oversight and support. The scheduled in-service dates of November 2021 and November 2022 for Vogtle Units No. 3 and No. 4, respectively, did not change in connection with these budget revisions.

Further, Georgia Power informed the Public Service Commission in its nineteenth VCM report that it did not intend to seek rate recovery for its proportionate share of the additional capital costs identified in that report. As a result of Georgia Power's decision not to seek rate recovery of its allocation of these costs and the increased construction budget, 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 voted to continue construction of Vogtle Units No. 3 and No. 4. In connection with our vote to continue construction with Vogtle Units No. 3 and No. 4, we approved a revised budget of $7.5 billion for our 30% ownership interest. The impact of the additional project costs on our budget was substantially mitigated by nearly $500 million of contingency included in our prior budget. As with our prior budgets and consistent with our conservative budget practices, our revised budget includes a separate Oglethorpe-level contingency amount in addition to capital costs, allowance for funds used during construction, and our allocation of the project-level contingency. 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 of September 30, 2018, our total investment in the additional Vogtle units was approximately $3.6 billion.

Based on the revised project budget, the following table provides an updated estimate of our forecasted capital expenditures, including allowance for funds used during construction, related to Vogtle Units No. 3 and No. 4 for 2018 through 2020 (dollars in millions).

	2018	2019	2020	Total
Future Generation	$986[1]	$1,182	$804	$2,972

[1] The estimate for 2018 is for the full year and includes actual capital expenditures through September 30, 2018.

In addition to the amounts reflected in the table above, we have budgeted approximately $1.5 billion to complete construction of Vogtle Units No. 3 and No. 4 beyond the years shown in the table. For additional information regarding our capital expenditures, see "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2017 Form 10-K.

In connection with the 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). We are working with the other Co-owners to clarify any interpretive issues related to the operation of certain provisions of the Term Sheet. Pursuant to the Term Sheet:

- each Co-owner will be 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 forms 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, 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);
- Georgia Power will be responsible for 65.7% of construction costs, subject to exceptions, 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 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 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(s) to be conveyed from the tendering Co-owner to Georgia Power would 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 would 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.

In the event the actual costs at completion of a unit are less than the EAC reflected in the nineteenth VCM report and (i) Vogtle Unit No. 3 is placed in service by the currently scheduled date of November 2021 or (ii) Vogtle Unit No. 4 is placed in service by the currently scheduled date of November 2022, Georgia Power would be entitled to 60.7% of the cost savings with respect to the relevant unit and the remaining Co-owners would be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

Pursuant to the Term Sheet, the Co-owners will continue to retain a third party to independently consult, advise and report to the Co-owners on issues pertaining to (i) project management and controls, (ii) organizational controls, (iii) commercial management plans and (iv) interim project reports until released by 67% of the Co-owners.

Pursuant to the Joint Ownership Agreements, as amended by the Term Sheet, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of

Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Term Sheet provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more over the most recently approved schedule. In addition, pursuant to the Joint Ownership Agreements, the required approval of holders of ownership interests in Vogtle Units No. 3 and No. 4 is at least (i) 90% for a change of the primary construction contractor and (ii) 67% for material amendments to the Services Agreement or agreements with Southern Nuclear or the primary construction contractor, including the Bechtel Agreement.

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

Subsequent to Westinghouse's bankruptcy filing, a number of subcontractors to Westinghouse alleged non-payment by Westinghouse for amounts owed for work performed on Vogtle Units No. 3 and No. 4. Georgia Power, acting for itself and as agent for the Co-owners, has taken actions to remove liens on the site filed by these subcontractors through the posting of surety bonds. Related to such liens, certain subcontractors have filed, and additional subcontractors may file, actions against Westinghouse and the Co-owners to preserve their payment rights with respect to such claims. All amounts associated with the removal of subcontractor liens and payment of other Westinghouse pre-petition accounts payable have been paid or accrued as of September 30, 2018.

We have a $3.1 billion federal loan guarantee from the Department of Energy, under which we have borrowed $1.8 billion as of September 30, 2018. Pursuant to the terms of the loan guarantee agreement, no further advances are permitted pending satisfaction of certain conditions. On September 28, 2017, the Department of Energy issued a conditional commitment to us for up to $1.6 billion of additional guaranteed funding under the loan guarantee agreement. The Department of Energy has extended the expiration date for this conditional commitment to March 31, 2019. Final approval and issuance of the additional loan guarantee by the Department of Energy cannot be assured and is subject to an amendment and restatement of the loan guarantee agreement and satisfaction of other conditions. For additional information regarding conditions for future advances, potential repayment over a five-year period, covenants and events of default under the loan guarantee agreement with the Department of Energy, see Note K of Notes to Unaudited Consolidated Financial Statements.

We have also financed $1.9 billion of the capital costs of the Vogtle units through capital market debt issuances. We anticipate financing any project costs not financed with Department of Energy in the capital markets. The timing and availability of funds under the Department of Energy loan guarantee will influence our decisions as to the timing of any capital markets offerings. For additional information regarding the financing of Vogtle Units No. 3 and No. 4, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Financial Condition—Capital Requirements and Liquidity and Sources of Capital—*Financing Activities—Department of Energy-Guaranteed Loan*."

Under the Bipartisan Budget Act of 2018, we qualify for nuclear production tax credits related to Vogtle Units No. 3 and No. 4. We expect to receive these tax credits in accordance with our 30% ownership interest in the Vogtle Units. We estimate that the nominal value of our allocation of production tax credits will be approximately $660 million and will be earned for eight years post commercial operation. Under the terms of the Term Sheet, Georgia Power agreed to purchase our allocation of production tax credits at varying purchase prices dependent upon the actual cost to complete construction of Vogtle Units No. 3 and No. 4 as compared to the EAC included in the nineteenth VCM report. Any purchases will be at our option. The purchases would occur during the month after such production tax credits are earned and would be at the following purchase prices: (i) 88% of face value if the actual cost remains at or below the EAC reflected in the nineteenth VCM report; (ii) 91% of face value if the actual cost increases by no more than $299 million over the EAC reflected in the nineteenth VCM report; (iii) 95% of face value if the actual cost increases $300 million but less than $600 million over the EAC reflected in the nineteenth VCM report; and (iv) 98% of face value if the actual cost increases by $600 million or more over the EAC reflected in the nineteenth VCM report. We will continue to analyze various options to monetize these credits with one or more third parties, including Georgia Power. In order to maximize the value of these production tax credits, we do not anticipate entering into any agreement to sell these production tax credits until one or both of the Vogtle Units reach commercial operation. We expect to use the proceeds received from the sale of production tax credits to offset operating costs following commercial operation of the Vogtle Units. Any amounts received from these sales will not affect our project budget.

In a filing with the Public Service Commission supporting the nineteenth VCM report, Georgia Power reported that, as of August 2018, overall construction on the Vogtle project was more than 55% complete and that the total project (which includes engineering, procurement, construction and other project phases) was over 70% complete. As construction continues, risks remain that construction-related challenges, including management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly and/or installation, including any required engineering changes, of plant systems, structures and components, or other issues could further impact the projected schedule and cost. Monthly construction production targets required to maintain the current project schedule continue to increase significantly through the remainder of 2018 and into 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed. Aspects of the Westinghouse AP1000 design are based on new technologies that only recently began commercial operation in the global nuclear industry at this scale.

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 assure 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. As a result of such compliance processes, 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 resolution of inspections, tests, analyses, and acceptance criteria and the related approvals by the Nuclear Regulatory Commission, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

MEAG is currently involved in litigation and Federal Energy Regulatory Commission (FERC) proceedings with JEA regarding a power purchase agreement for approximately 9% of the total output of Vogtle Units No. 3 and No. 4 for the first 20 years of operation. This litigation could impact MEAG's ability to finance the MEAG Power SPVJ portion of its interest in Vogtle Units No. 3 and No. 4; however, there are provisions in the Joint Ownership Agreements that permit the other Co-owners to fund construction in the event that one Co-owner fails to fund its proportionate costs. MEAG and Georgia Power have executed a term sheet for Georgia Power to provide MEAG up to an additional $300 million of financing. JEA has publicly stated that it intends to honor its obligations under the power purchase agreement unless relieved of its obligations by a court or FERC. MEAG has stated that it believes JEA's claims are without merit and that it will prevail in these proceedings.

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

Environmental Regulations

Federal and state laws and regulations regarding environmental matters affect operations at our facilities and are subject to change over time.

The Trump Administration continues to curtail the Obama Administration's actions to limit carbon dioxide emissions. In August 2018, EPA issued a proposed Affordable Clean Energy (ACE) rule which is intended to replace the Clean Power Plan finalized in 2015. The final ACE rule is expected in spring of 2019. The proposed rule is an "inside the fence" regulation that defines the Best System of Emissions Reduction (BSER) for carbon dioxide as heat rate improvement measures, or a highly efficient facility. The proposed ACE rule gives states flexibility in using the BSER to set the standard of performance for affected units on a source-specific basis and for establishing compliance requirements, including compliance deadlines. States are allowed to consider remaining useful life and other factors in setting standards of performance for affected units. Because heat rate improvement measures may trigger New Source Review (NSR), the proposed ACE rule also modifies the NSR program by adding a "maximum hourly emission increase" test that reduces the likelihood of triggering NSR requirements. We cannot predict the outcome of the proposed ACE rule, or other regulatory changes, agency actions, or executive orders related to environmental issues, including climate change, nor can we predict the outcome or effect of possible litigation resulting from any of these actions.

On August 21, 2018, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision that addressed all remaining issues raised by industry and environmental groups in the "coal combustion residuals" (CCR) litigation. In its decision, the D.C. Circuit vacated and remanded portions of EPA's final CCR rule, issued on April 17, 2015, regulating the disposal of CCR generated by power plants. Among other things, the court ruled that the current federal CCR requirements for unlined and clay-lined surface impoundments must be revised to address potential risks of leakage that may occur from these impoundments. At this time, EPA is evaluating how to best respond to the court's ruling. EPA's response may include the initiation of a notice-and-comment rulemaking to revise the substantive requirements of the federal CCR rule. In addition, the court's ruling could affect recent and planned EPA rulemaking efforts to establish, among other things, a permit program for flexible implementation of the federal CCR requirements, as recently authorized by Congress through federal legislation. We cannot predict the outcome of the D.C. Circuit ruling, including any future EPA rulemaking efforts or administrative responses thereto, on CCR plant operations at this time.

For a discussion regarding potential effects on our business from environmental regulations, including potential capital requirements, see "Item 1—BUSINESS—REGULATION—Environmental," "Item 1A—RISK FACTORS" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2017 Form 10-K.

Liquidity

At September 30, 2018, we had $1.38 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $718 million in cash and cash equivalents and $662 million of unused and available committed credit arrangements.

At September 30, 2018, we had $1.61 billion of committed credit arrangements in place, the details of which are reflected in the table below:

Committed Credit Facilities

	Authorized Amount	Available September 30, 2018	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit led by CFC	$1,210	$378[1]	March 2020
CFC Line of Credit[2]	110	110	December 2018
JPMorgan Chase Line of Credit	150	34[3]	October 2021
Secured Facilities:			
CFC Term Loan[2]	140	140	December 2018
Total	$1,610	$662	

(1) Of the portion of this facility that was unavailable at September 30, 2018, $696 million was dedicated to support outstanding commercial paper and $136 million was related to letters of credit issued to support variable rate demand bonds.

(2) Under the secured term loan with CFC, we can borrow up to $250 million. However, any amounts drawn under the $110 million unsecured line of credit with CFC will reduce the amount that can be drawn under the term loan. Therefore, we reflect $140 million as the amount authorized and available under the term loan even though no amounts have been borrowed 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) Of the portion of this facility that was unavailable at September 30, 2018, $114 million related to letters of credit issued to support variable rate demand bonds and $2 million related to letters of credit issued to post collateral to third parties.

Currently, we are primarily using our commercial paper program to provide interim funding for payments related to the construction of Vogtle Units No. 3 and No. 4 prior to receiving advances of long-term funding under the Department of Energy-guaranteed Federal Financing Bank loan or issuing debt in the capital markets. At September 30, 2018, $696 million of commercial paper was outstanding related to the Vogtle construction. On October 31, 2018, we retired $492 million of commercial paper with proceeds from a $500 million issuance of first mortgage bonds, which decreased the amount of commercial paper outstanding to $275 million. See Note K of Notes to Unaudited Consolidated Financial Statements and "*—Financing Activities—Department of Energy-Guaranteed Loan*" for a discussion of our first mortgage bond issuance and our ability to request further loan advances from the Department of Energy pending satisfaction of certain conditions relating to the Vogtle project.

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. Our commercial paper program is currently sized at $1.0 billion.

In August 2018, we renewed our $150 million line of credit with JPMorgan Chase Bank for a term of three years. We expect to renew our two credit facilities with CFC before their December 2018 expiration dates.

Under our unsecured committed lines of credit, we have the ability to issue letters of credit totaling $760 million in the aggregate, of which $509 million remained available at September 30, 2018. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under our committed credit facilities for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue. The majority of our outstanding letters of credit are for the purpose of providing credit enhancement on variable rate demand bonds.

Two of our credit facilities contain a financial covenant that requires us to maintain a minimum level of patronage capital. At September 30, 2018, the required minimum level was $750 million and our actual patronage capital was $967 million. These agreements contain an additional covenant that limits our secured indebtedness and unsecured indebtedness, both as defined in the credit agreements, to $12.0 billion and $4.0 billion, respectively. At September 30, 2018, we had $8.4 billion of secured indebtedness and $696 million of unsecured indebtedness outstanding.

At September 30, 2018, we had $755.2 million on deposit in the Rural Utilities Service Cushion of Credit Account, all of which is classified as a restricted investment. See "—Balance Sheet Analysis as of September 30, 2018—*Assets*" for more information regarding this account.

Financing Activities

First Mortgage Indenture. At September 30, 2018, we had $8.4 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 2017 Form 10-K for further discussion of our first mortgage indenture.

On October 30, 2018, we issued $500 million of Series 2018A first mortgage bonds to fund a portion of the Vogtle expansion project. The bonds are secured under our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. At September 30, 2018, we had one approved Rural Utilities Service-guaranteed loan being funded through the Federal Financing Bank in the amount of $448 million, with $161 million remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture. As of September 30, 2018, we had $2.6 billion of debt outstanding under various Rural Utilities Service-guaranteed loans.

Department of Energy-Guaranteed Loan. In 2014, we entered into a loan guarantee agreement with the Department of Energy to fund up to $3.1 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. The loan is being funded by the Federal Financing Bank and is backed by a federal loan guarantee provided by the Department of Energy. At September 30, 2018, we had borrowed $1.8 billion under this loan, including capitalized interest.

Our last advance under this loan was in December 2016. Following the bankruptcy of Westinghouse in March 2017, the loan guarantee agreement was amended to restrict further advances pending satisfaction of certain conditions, including a further amendment to the loan guarantee agreement to incorporate provisions related to the Bechtel Agreement and other replacement agreements. In September 2017, the Department of Energy issued a conditional commitment to us for $1.6 billion of additional funding under the loan guarantee agreement. This additional funding is subject to an amendment and restatement of the loan guarantee agreement, completion of due diligence by the Department of Energy, receipt of any necessary regulatory approvals and satisfaction of certain other conditions.

The conditional commitment expires on March 31, 2019, subject to any extension approved by the Department of Energy. If closed, our aggregate Department of Energy loan financing for the Vogtle expansion project will increase to nearly $4.7 billion. Final approval and issuance of the additional loan guarantee cannot be assured.

All of the debt advanced under the loan guarantee agreement is secured ratably with all other debt under our first mortgage indenture. For additional information regarding this loan, see Note K of Notes to Unaudited Consolidated Financial Statements.

Including our issuance of $500 million of first mortgage bonds on October 30, 2018, to-date we have issued in the aggregate approximately $3.7 billion of long-term debt obligations to fund our share of the Vogtle project. In addition to the Department of Energy funding advanced to-date, we have issued $1.9 billion of first mortgage bonds to finance the Vogtle expansion. We expect to finance any Vogtle project costs not covered by the Department of Energy-guaranteed loans with additional capital market financings.

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 2017 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 not been any material changes to market risks from those reported in "Item 7A—QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK" of our 2017 Form 10-K.

Item 4. Controls and Procedures

As of September 30, 2018, 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, 2018 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 2017 Form 10-K.

Item 1A. Risk Factors

Except as described below, there have been no material changes to the risk factors previously disclosed.

Our participation in the development and construction of Vogtle Units No. 3 and No. 4 could have a material impact on our financial condition and results of operations.

We are participating in the construction of two additional nuclear units at Plant Vogtle and have committed significant capital expenditures to this endeavor. The construction of large, complex generating plants involves significant financial risk. We rely on Georgia Power and Southern Nuclear as our agents for the oversight of the construction of the additional units at Plant Vogtle and do not exercise direct control over the construction process.

Earlier in 2018, Georgia Power advised us that it became aware that the estimated future Vogtle project costs were projected to exceed the corresponding budgeted amounts included in its seventeenth VCM report. Upon discovery of these variances, the Co-owners requested Southern Nuclear perform a full cost analysis and reforecast the cost to complete the project and engaged a third party to independently assess this analysis, forecast, and existing project controls for identifying budget variances. Following this analysis, Georgia Power proposed an increased construction budget and included a revised estimate to complete in its nineteenth VCM report filed with the Georgia Public Service Commission in August 2018. This revised estimate included an approximate $1.5 billion increase in capital costs (our 30% share is approximately $450 million) and a project-level contingency in an amount of $800 million (our 30% share is $240 million). The increase in the revised budget is primarily attributable to Bechtel and subcontractor construction costs, including craft labor incentives, as well as expenses for project management, oversight and support. The scheduled in-service dates of November 2021 and November 2022 for Vogtle Units No. 3 and No. 4, respectively, did not change in connection with these budget revisions.

Further, Georgia Power informed the Public Service Commission in its nineteenth VCM report that it did not intend to seek rate recovery for its proportionate share of the additional capital costs identified in that report. As a result of Georgia Power's decision not to seek rate recovery of its allocation of these costs and the increased construction budget, 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 voted to continue construction of Vogtle Units No. 3 and No. 4. In connection with our vote to continue construction with Vogtle Units No. 3 and No. 4, we approved a revised budget of $7.5 billion for our 30% ownership interest. The impact of the additional project costs on our budget was substantially mitigated by nearly $500 million of contingency included in our prior budget. As with our prior budgets and consistent with our conservative budget practices, our revised budget includes a separate Oglethorpe-level contingency amount in addition to capital costs, allowance for funds used during construction, and our allocation of the project-level contingency.

The revised budget increased our estimated capital expenditures through 2022 and, as a result, our estimated long-term debt outstanding following completion of the Vogtle units increased to approximately $11.8 billion. These increases in capital expenditures and long-term debt will continue to constrain our equity ratio and will affect certain of our financial metrics. Increased debt and the related impacts on our financial metrics could negatively impact our credit ratings. Any downgrade in our credit ratings would increase our borrowing costs and decrease our access to the credit and capital markets.

We and the other Co-owners are responsible for construction costs based on our ownership percentages. Factors that could lead to further cost increases and schedule delays or even the inability to complete this project include:

- performance by Georgia Power as agent for the Co-owners and performance by Southern Nuclear as construction manager;
- performance by Bechtel under the Bechtel Agreement as well as subcontractor and supplier performance, including compliance with the design specifications approved and quality standards set forth by the Nuclear Regulatory Commission;
- shortages and/or inconsistent quality of labor, equipment and materials;
- changes in labor costs and productivity;
- performance by Westinghouse under the Services Agreement;
- loss of access to intellectual property rights necessary to construct or operate the project;
- increases in our cost of debt financing as a result of changes in market interest rates or as a result of construction schedule delays;
- unforeseen engineering or design problems;
- erosion of public and policymaker support;
- liens on the project;
- contract disputes;
- permits, approvals and other regulatory matters;
- unanticipated increases in the costs of materials;
- changes in project design or scope;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- adverse weather conditions; and
- work stoppages.

However, pursuant to the Term Sheet, Georgia Power agreed to mitigate certain financial exposure for the Co-owners. In the event that construction costs exceed the EAC in the nineteenth VCM report by more than $800 million up to $2.1 billion, Georgia Power will be responsible for an increasing percentage of construction costs, subject to exceptions, up to a maximum of an additional $180 million, and each Co-owner would maintain its existing ownership interest. In the event that the EAC 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 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. 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. We are working with the other Co-owners to clarify any interpretive issues related to the operation of certain provisions of the Term Sheet.

Pursuant to the Joint Ownership Agreements, as amended by the Term Sheet, the holders of at least 90% of the ownership interests in Vogtle Units No. 3 and No. 4 must vote to continue construction, or can vote to suspend construction, if certain adverse events occur, including: (i) the bankruptcy of Toshiba Corporation; (ii) termination or rejection in bankruptcy of certain agreements, including the Services Agreement, the Bechtel Agreement or the agency agreement with Southern Nuclear;

(iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Vogtle Units No. 3 and No. 4 (or associated financing costs) or the Georgia Public Service Commission determines that any of Georgia Power's costs relating to the construction of Vogtle Units No. 3 and No. 4 will not be recovered in retail rates, excluding any additional amounts paid by Georgia Power on behalf of the other Co-owners pursuant to the Term Sheet provisions described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Public Service Commission for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates or (iv) an incremental extension of one year or more over the most recently approved schedule.

As of September 30, 2018, our total investment in the additional Vogtle units was approximately $3.6 billion. The Term Sheet provides that Georgia Power may cancel the project at any time in its sole discretion. In the event that Georgia Power determines to cancel the project or fewer than 90% of the Co-owners vote to continue construction upon the occurrence of a subsequent project adverse event, we and the other Co-owners would assess our options for the Vogtle project. If the investment were to be written off, we would seek regulatory accounting treatment to amortize the investment over a long-term period, which requires the approval of our board of directors, and we would submit the regulatory accounting treatment details to the Rural Utilities Service for its approval. Further, if Georgia Power or the Co-owners decided to cancel the project, the Department of Energy would have the discretion to require that we repay all amount outstanding under the loan guarantee agreement over a five-year period.

In a filing with the Public Service Commission supporting the nineteenth VCM report, Georgia Power reported that, as of August 2018, overall construction on the Vogtle project was more than 55% complete and that the total project (which includes engineering, procurement, construction and other project phases) was over 70% complete. As construction continues, risks remain that construction-related challenges, including management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly and/or installation, including any required engineering changes, of plant systems, structures and components, or other issues could further impact the projected schedule and cost. Monthly construction production targets required to maintain the current project schedule continue to increase significantly through the remainder of 2018 and into 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed. Aspects of the Westinghouse AP1000 design are based on new technologies that only recently began commercial operation in the global nuclear industry at this scale.

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 assure 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. As a result of such compliance processes, 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 resolution of inspections, tests, analyses, and acceptance criteria and the related approvals by the Nuclear Regulatory Commission, may arise, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be further delays in the project schedule that could result in increased costs to the Co-owners.

The long-term project cost will also be impacted by our ability to finance the capital costs at competitive interest rates. We have a $3.1 billion federal loan guarantee from the Department of Energy, under which we have borrowed $1.8 billion as of September 30, 2018. Pursuant to the terms of the loan guarantee agreement, no further advances are permitted pending satisfaction of certain conditions. On September 28, 2017, the Department of Energy issued a conditional commitment to us for up to $1.6 billion of additional guaranteed funding under the loan guarantee agreement. The Department of Energy has extended the expiration date for this conditional commitment to March 31, 2019. Final approval and issuance of the additional loan guarantee by the Department of Energy cannot be assured and is subject to an amendment and restatement of the loan guarantee agreement and satisfaction of other conditions.

We anticipate financing any project costs not financed with Department of Energy in the capital markets. The timing and availability of funds under the Department of Energy loan guarantee will influence our decisions as to the timing of any capital markets offerings. Prolonged inability to access funding pursuant to the Department of Energy loan guarantee agreement may constrain our liquidity and lead us to finance certain expenditures through alternative resources, likely at a higher interest rate.

MEAG is currently involved in litigation and FERC proceedings with JEA regarding a power purchase agreement for approximately 9% of the total output of Vogtle Units No. 3 and No. 4 for the first 20 years of operation. This litigation could impact MEAG's ability to finance the MEAG Power SPVJ portion of its interest in Vogtle Units No. 3 and No. 4; however, there are provisions in the Joint Ownership Agreements that permit the other Co-owners to fund construction in the event that one Co-owner fails to fund its proportionate costs. MEAG and Georgia Power have executed a term sheet for Georgia Power to provide MEAG up to an additional $300 million of financing. JEA has publicly stated that it intends to honor its obligations under the power purchase agreement unless relieved of its obligations by a court or FERC. MEAG has stated that it believes JEA's claims are without merit and that it will prevail in these proceedings.

The ultimate outcome of these matters cannot be determined at this time; however, these risks could continue to impact the in-service dates and cost of the additional units at Plant Vogtle which would increase the cost of electric service we provide to our members and, as a result, could affect their ability to perform their contractual obligations to us.

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

Not Applicable.

Item 3. Defaults upon Senior Securities

Not Applicable.

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

Not Applicable.

Item 6. Exhibits

Number	Description
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.

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 9, 2018	By: /s/ Michael L. Smith
	Michael L. Smith President and Chief Executive Officer
Date: November 9, 2018	/s/ Elizabeth B. Higgins
	Elizabeth B. Higgins Executive Vice President and Chief Financial Officer (Principal Financial Officer)