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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015

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. 000-53908

OglethorpePower

(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 or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one): **Large Accelerated Filer** ☐ **Accelerated Filer** ☐ **Non-Accelerated Filer** ☒ Do not check if a smaller reporting company) **Smaller Reporting Company** ☐

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 JUNE 30, 2015

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 the timing of various regulatory and other actions, future capital expenditures, business strategy 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, 2014. 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;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- the regulation of carbon dioxide emissions, such as the proposed Clean Power Plan or other potential legislative and regulatory responses to climate change initiatives or efforts to reduce other greenhouse gas emissions;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- increasing debt caused by significant capital expenditures which is weakening certain of our financial metrics;
- commercial banking and financial market conditions;
- 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;
- uncertainty as to the continued availability of funding from the Rural Utilities Service and our continued eligibility to receive advances from the U.S. Department of Energy for construction of two additional nuclear units at Plant Vogtle;
- actions by credit rating agencies;
- risks and regulatory requirements related to the ownership and construction of nuclear facilities;

- adequate funding of our nuclear decommissioning trust fund 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;
- litigation or legal and administrative proceedings and settlements;
- the credit quality and/or inability of various counterparties to meet their financial obligations to us, including failure to perform under agreements;
- our members' ability to perform their obligations to us;
- changes to protections granted by the Georgia Territorial Act that subject our members to increased competition;
- changes in technology available to and utilized by us, our competitors, or residential or commercial consumers in our members' service territories;
- general economic conditions;
- weather conditions and other natural phenomena;
- unanticipated variation in demand for electricity or load forecasts resulting from changes in population and business growth (and declines), consumer consumption, energy conservation efforts and the general economy;
- unanticipated changes in interest rates or rates of inflation;
- significant changes in our relationship with our employees, including the availability of qualified personnel;
- unanticipated changes in capital expenditures, operating expenses and liquidity needs;
- 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)
June 30, 2015 and December 31, 2014

	(dollars in thousands)	
	2015	2014
Assets		
Electric plant:		
In service	**$ 8,430,496**	$ 8,345,241
Less: Accumulated provision for depreciation	**(3,837,389)**	(3,762,690)
	4,593,107	4,582,551
Nuclear fuel, at amortized cost	**360,297**	369,529
Construction work in progress	**2,507,335**	2,374,392
	7,460,739	7,326,472
Investments and funds:		
Nuclear decommissioning trust fund	**373,236**	366,004
Investment in associated companies	**68,230**	67,368
Long-term investments	**84,833**	85,728
Restricted cash and investments	**76,535**	118,390
Other	**18,316**	17,397
	621,150	654,887
Current assets:		
Cash and cash equivalents	**286,777**	237,391
Restricted short-term investments	**252,652**	247,057
Receivables	**141,537**	130,366
Inventories, at average cost	**267,992**	270,849
Prepayments and other current assets	**23,260**	12,667
	972,218	898,330
Deferred charges:		
Deferred debt expense, being amortized	**97,553**	97,902
Regulatory assets	**513,026**	484,049
Prepayments to Georgia Power Company	**80,580**	73,726
Other	**11,750**	10,877
	702,909	666,554
	$ 9,757,016	$ 9,546,243

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

Oglethorpe Power Corporation
Consolidated Balance Sheets (Unaudited)
June 30, 2015 and December 31, 2014

	(dollars in thousands)	
	2015	2014
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 787,345**	$ 761,124
Accumulated other comprehensive margin	**107**	468
	787,452	761,592
Long-term debt	**7,326,478**	7,113,000
Obligation under capital leases	**98,532**	100,456
Other	**16,988**	16,434
	8,229,450	7,991,482
Current liabilities:		
Long-term debt and capital leases due within one year	**161,294**	160,754
Short-term borrowings	**261,744**	234,369
Accounts payable	**42,924**	98,337
Accrued interest	**58,792**	58,841
Member power bill prepayments, current	**143,681**	166,013
Other current liabilities	**54,619**	70,748
	723,054	789,062
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**19,936**	20,676
Asset retirement obligations	**465,573**	432,260
Member power bill prepayments, non-current	**43,240**	31,941
Power sale agreement, being amortized	**6,334**	12,669
Regulatory liabilities	**192,970**	194,073
Other	**76,459**	74,080
	804,512	765,699
	$9,757,016	$9,546,243

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

Oglethorpe Power Corporation
Consolidated Statements of Revenues and Expenses (Unaudited)
For the Three and Six Months Ended June 30, 2015 and 2014

	(dollars in thousands)			
	Three Months		Six Months	
	2015	2014	**2015**	2014
Operating revenues:				
Sales to Members	**$311,148**	$338,116	**$619,924**	$672,875
Sales to non-Members	**32,593**	17,867	**63,595**	50,408
Total operating revenues	**343,741**	355,983	**683,519**	723,283
Operating expenses:				
Fuel	**115,211**	133,976	**223,620**	266,252
Production	**128,369**	99,004	**243,128**	207,088
Depreciation and amortization	**42,952**	41,404	**85,604**	82,118
Purchased power	**14,612**	16,312	**28,243**	36,378
Accretion	**6,477**	6,108	**12,859**	12,126
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(27,374)**	(10,421)	**(41,689)**	(20,136)
Total operating expenses	**280,247**	286,383	**551,765**	583,826
Operating margin	**63,494**	69,600	**131,754**	139,457
Other income:				
Investment income	**10,185**	9,145	**20,034**	18,427
Amortization of deferred gains	**370**	447	**740**	894
Allowance for equity used during construction	**168**	342	**342**	731
Other	**1,903**	1,443	**4,218**	2,984
Total other income	**12,626**	11,377	**25,334**	23,036
Interest charges:				
Interest expense	**88,132**	85,965	**175,839**	167,882
Allowance for debt funds used during construction	**(26,699)**	(26,385)	**(52,952)**	(50,114)
Amortization of debt discount and expense	**3,835**	4,201	**7,980**	8,306
Net interest charges	**65,268**	63,781	**130,867**	126,074
Net margin	**$ 10,852**	$ 17,196	**$ 26,221**	$ 36,419

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 Six Months Ended June 30, 2015 and 2014

	(dollars in thousands)			
	Three Months		Six Months	
	2015	2014	**2015**	2014
Net margin	**$10,852**	$17,196	**$26,221**	$36,419
Other comprehensive margin:				
Unrealized (loss) gain on available-for-sale securities	**(314)**	431	**(361)**	827
Total comprehensive margin	**$10,538**	$17,627	**$25,860**	$37,246

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 Six Months Ended June 30, 2015 and 2014

(dollars in thousands)

	Patronage Capital and Membership Fees	**Accumulated Other Comprehensive Margin (Deficit)**	**Total**
Balance at December 31, 2013	$714,489	$(549)	$713,940
Components of comprehensive margin:			
Net margin	36,419	—	36,419
Unrealized gain on available-for-sale securities	—	827	827
Balance at June 30, 2014	$750,908	$ 278	$751,186
Balance at December 31, 2014	$761,124	$ 468	$761,592
Components of comprehensive margin:			
Net margin	26,221	—	26,221
Unrealized loss on available-for-sale securities	—	(361)	(361)
Balance at June 30, 2015	**$787,345**	**$ 107**	**$787,452**

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

Oglethorpe Power Corporation
Consolidated Statements of Cash Flows (Unaudited)
For the Six Months Ended June 30, 2015 and 2014

	(dollars in thousands)	
	2015	2014
Cash flows from operating activities:		
Net margin	**$ 26,221**	$ 36,419
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**156,416**	153,759
Accretion cost	**12,859**	12,126
Amortization of deferred gains	**(894)**	(894)
Allowance for equity funds used during construction	**(342)**	(731)
Deferred outage costs	**(18,274)**	(31,411)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(41,689)**	(20,136)
Gain on sale of investments	**(32,470)**	(8,961)
Regulatory deferral of costs associated with nuclear decommissioning	**25,781**	1,571
Other	**13,216**	6,816
Change in operating assets and liabilities:		
Receivables	**(11,171)**	(21,180)
Inventories	**2,857**	32,455
Prepayments and other current assets	**(10,664)**	1,209
Accounts payable	**(45,059)**	(45,456)
Accrued interest	**(49)**	183
Accrued taxes	**820**	(3,978)
Other current liabilities	**(8,681)**	(2,479)
Member power bill prepayments	**(11,033)**	14,475
Total adjustments	**31,623**	87,368
Net cash provided by operating activities	**57,844**	123,787
Cash flows from investing activities:		
Property additions	**(256,038)**	(249,317)
Activity in nuclear decommissioning trust fund—Purchases	**(281,938)**	(188,815)
—Proceeds	**279,751**	186,165
Decrease in restricted cash and investments	**41,855**	32,209
Increase in restricted short-term investments	**(5,524)**	(21,173)
Activity in other long-term investments—Purchases	**(23,746)**	(28,690)
—Proceeds	**24,973**	30,385
Activity on interest rate options—Collateral returned	**—**	(73,850)
—Collateral received	**—**	41,640
Other	**(8,450)**	473
Net cash used in investing activities	**(229,117)**	(270,973)
Cash flows from financing activities:		
Long-term debt proceeds	**271,892**	993,707
Long-term debt payments	**(76,418)**	(333,127)
Increase (decrease) in short-term borrowings, net	**27,375**	(548,494)
Other	**(2,190)**	(43,227)
Net cash provided by financing activities	**220,659**	68,859
Net increase (decrease) in cash and cash equivalents	**49,386**	(78,327)
Cash and cash equivalents at beginning of period	**237,391**	408,193
Cash and cash equivalents at end of period	**$ 286,777**	$ 329,866
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 127,026**	$ 115,231
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	**$ (8,454)**	$ 22,904

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

Oglethorpe Power Corporation
Notes to Unaudited Consolidated Financial Statements
For the Three and Six Months ended June 30, 2015 and 2014

(A) *General.* The consolidated financial statements included in this report have been prepared by us pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the information furnished in this report reflects all adjustments (which include only normal recurring adjustments) and estimates necessary to fairly state, in all material respects, the results for the three- month and six-month periods ended June 30, 2015 and 2014. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to SEC rules and regulations, although we believe that the disclosures are adequate to make the information presented not misleading. These 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, 2014, as filed with the SEC. The results of operations for the three-month and six-month periods ended June 30, 2015 are not necessarily indicative of results to be expected for the full year. As noted in our 2014 Form 10-K, our revenues consist primarily of sales to our 38 electric distribution cooperative members and, thus, the receivables on the consolidated balance sheets are principally from our members. (See "Notes to Financial Statements" in our 2014 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 June 30, 2015 and December 31, 2014.

		Fair Value Measurements at Reporting Date Using		
	June 30, 2015	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	**$155,440**	$155,440	$ —	$ —
International equity trust	**74,017**	—	74,017	—
Corporate bonds	**38,834**	—	38,834	—
US Treasury and government agency securities	**75,625**	75,625	—	—
Agency mortgage and asset backed securities	**16,108**	—	16,108	—
Municipal bonds	**916**	—	916	—
Other	**12,296**	12,296	—	—
Long-term investments:				
International equity trust	**12,566**	—	12,566	—
Corporate bonds	**6,179**	—	6,179	—
US Treasury and government agency securities	**16,781**	16,781	—	—
Agency mortgage and asset backed securities	**926**	—	926	—
Mutual funds	**48,172**	48,172	—	—
Other	**209**	209	—	—
Interest rate options	**4,715**	—	—	4,715
Natural gas swaps	**15,942**	—	15,942	—

	Fair Value Measurements at Reporting Date Using			
	December 31, 2014	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	$159,536	$159,536	$ —	$ —
International equity trust	72,474	—	72,474	—
Corporate bonds	34,446	—	34,446	—
US Treasury and government agency securities	68,854	68,854	—	—
Agency mortgage and asset backed securities	16,148	—	16,148	—
Municipal Bonds	743	—	743	—
Other	13,803	13,803	—	—
Long-term investments:				
Corporate bonds	5,445	—	5,445	—
US Treasury and government agency securities	16,619	16,619	—	—
Agency mortgage and asset backed securities	643	—	643	—
International equity trust	11,162	—	11,162	—
Mutual funds	51,741	51,741	—	—
Other	118	118	—	—
Interest rate options	4,371	—	—	4,371
Natural gas swaps	18,914	—	18,914	—

The Level 2 investments above in corporate bonds and agency mortgage and asset 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 following tables present the changes in Level 3 assets measured at fair value on a recurring basis during the three and six months ended June 30, 2015 and 2014.

	Three Months Ended June 30, 2015
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at March 31, 2015	$ 2,702
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	2,013
Balance at June 30, 2015	**$ 4,715**

	Three Months Ended June 30, 2014
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at March 31, 2014	$ 31,463
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(12,928)
Balance at June 30, 2014	$ 18,535

	Six Months Ended June 30, 2015
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at December 31, 2014	$ 4,371
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	344
Balance at June 30, 2015	**$ 4,715**

	Six Months Ended June 30, 2014
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at December 31, 2013	$ 63,471
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(44,936)
Balance at June 30, 2014	$ 18,535

We estimate the value of the interest rate options as the sum of time value and any intrinsic value minus a counterparty credit adjustment. Intrinsic value is the value of the underlying swap, which we are able to calculate based on the forward LIBOR swap rates, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, all of which we are able to effectively observe. Time value is the additional value of the swaption due to the fact that it is an option. We estimate the time value using an option pricing model which, in addition to the factors used to calculate intrinsic value, also takes into account option volatility, which we estimate based on option valuations we obtain from various sources. We estimate the counterparty credit adjustment by observing credit attributes, including the credit default swap spread of entities similar to the counterparty and the amount of credit support that is available for each swaption. Since the primary component of the LIBOR swaptions' value is time value, which is based on estimated option volatility derived from valuations of comparable instruments that are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We believe the estimated fair values for the LIBOR swaptions we hold are based on the most accurate information available for these types of derivative contracts. For additional information regarding our interest rate options, see Note C.

The estimated fair values of our long-term debt, including current maturities at June 30, 2015 and December 31, 2014 were as follows (in thousands):

	2015		2014	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$7,476,491**	**$8,281,385**	$7,256,995	$8,460,685

The estimated fair value of long-term debt is classified as Level 2 and is estimated based on observed or quoted market prices for the same or similar issues or on current rates offered to us for debt of similar maturities. The primary sources of our long-term debt consist of first mortgage bonds, pollution control revenue bonds and long-term debt issued by the Federal Financing Bank that is guaranteed by the Rural Utilities Service or the U.S. Department of Energy. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC) and by CoBank, ACB. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from third party investment banking firms and a third party data provider, and are based on secondary market trading of our debt. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of June 30, 2015 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. We use an interest rate quote sheet provided by CoBank for valuation of the CoBank debt, which reflects current rates for a similar loan.

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

(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. To hedge the risk of rising interest rates on long-term debt in connection with capital expenditures, we have entered into interest rate options. We do not apply hedge accounting for any of these derivatives, but apply regulatory accounting. Consistent with our rate-making, unrealized gains or losses on our natural gas swaps and interest rate options 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 and/or interest rates could cause us to have credit risk exposures with one or more counterparties. We currently have credit risk exposure to our interest rate options counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of June 30, 2015, 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 and interest rate option 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 our natural gas swap arrangements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment.

At June 30, 2015 and December 31, 2014, the fair value of our natural gas contracts was a net liability of approximately $15,942,000 and $18,914,000, respectively.

As of June 30, 2015 and December 31, 2014, neither we nor any counterparties were required to post credit support or collateral under these natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on June 30, 2015 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit in the amount of $16,158,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of June 30, 2015 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2015	12.9
2016	13.8
2017	3.2
Total	**29.9**

Interest rate options. We are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we expect to incur in connection with anticipated capital expenditures, particularly the construction of Vogtle Units No. 3 and No. 4. In fourth quarter of 2011, we purchased LIBOR swaptions at a cost of $100,000,000 with a total notional amount of approximately $2,200,000,000 to hedge the interest rates on a portion of the debt that we are incurring to finance the two additional nuclear units at Plant Vogtle. Since inception, swaptions having a notional amount of approximately $1,549,683,000 have expired and as of June 30, 2015 the remaining notional amount of our outstanding swaptions was approximately $629,520,000.

The LIBOR swaptions are each designed to cap our effective interest rate at a specified fixed interest rate on a specified option expiration date. This is accomplished by means of a payment of the cash settlement value our counterparties are obligated to make to us if prevailing fixed LIBOR swap rates exceed the specified fixed rate on the option expiration date. This payment would partially offset our interest costs, thereby reducing our effective interest rate. The cash settlement value would be zero if swap rates are at or below the specified fixed rate on the expiration date. The cash settlement value is calculated based on the value of an underlying swap which we have the right, but not the obligation, to enter into, which would begin on the option expiration date and extend until 2042 and under which we would pay the specified fixed rate and receive a floating LIBOR rate. The fixed rates on the unexpired swaptions we hold average 127 basis points above the corresponding LIBOR swap rates that were in effect as of June 30, 2015, and the weighted average fixed rate is 3.98%. Swaptions having notional amounts totaling $231,806,000 expired without value during the six months ended June 30, 2015. The remaining swaptions expire quarterly through 2017.

We paid all the premiums to purchase these LIBOR swaptions at the time we entered into these transactions. At June 30, 2015 and December 31, 2014, the fair value of these swaptions was approximately $4,715,000 and $4,371,000, respectively. To manage our credit exposure to our counterparties, we negotiated credit support provisions that require each counterparty to provide us collateral in the form of cash or securities to the extent that the value of the swaptions outstanding for that counterparty exceeds a certain threshold. The collateral thresholds can range from $0 to $10,000,000 depending on each counterparty's credit rating. As of June 30, 2015 and December 31, 2014, there were no collateral postings made by the counterparties, respectively.

We are deferring unrealized gains or losses from the change in fair value of each LIBOR swaption and related carrying and other incidental costs in accordance with our rate-making treatment. The realized deferred costs and deferred gains, if any, from the settlement of the interest rate options will be amortized and collected in rates over the life of the $2,200,000,000 of debt that we hedged with the swaptions.

The following table reflects the remaining notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of June 30, 2015.

Year	**LIBOR Swaption Notional Dollar Amount** (in thousands)
2015	$238,818
2016	310,533
2017	80,169
Total	**$629,520**

The table below reflects the fair value of derivative instruments and their effect on our consolidated balance sheets at June 30, 2015 and December 31, 2014.

	Balance Sheet Location	**Fair Value**	
		2015	2014
		(dollars in thousands)	
Not designated as hedges:			
Assets:			
Interest rate options	Other deferred charges	**$ 4,715**	$ 4,371
Liabilities:			
Natural gas swaps	Other current liabilities	**$10,198**	$13,418
Natural gas swaps	Other deferred credits	**5,744**	5,496

The following table presents the gross realized gains and (losses) on derivative instruments recognized in margin for the three and six months ended June 30, 2015 and 2014.

	Statement of Revenues and Expenses Location	**Three months ended June 30,**		**Six months ended June 30,**	
		2015	2014	**2015**	2014
		(dollars in thousands)			
Not Designated as hedges:					
Natural Gas Swaps	Fuel	**$ 181**	$956	**$ 181**	$1,236
Natural Gas Swaps	Fuel	**(3,248)**	—	**(8,775)**	—
		$(3,067)	$956	**$(8,594)**	$1,236

The following table presents the unrealized gains and (losses) on derivative instruments deferred on the balance sheet at June 30, 2015 and December 31, 2014.

	Balance Sheet Location	**2015**	2014
		(dollars in thousands)	
Not designated as hedges:			
Natural gas swaps	Regulatory asset	**$(15,942)**	$(18,914)
Interest rate options	Regulatory asset	**(36,323)**	(49,232)
Total not designated as hedges		**$(52,265)**	$(68,146)

The following table presents the gross amounts of derivatives and their related offset amounts as permitted by their respective master netting agreements and obligations to return cash collateral.

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts offset on the Balance Sheet	Cash Collateral	Net Amounts of Assets Presented on the Balance Sheet
	(dollars in thousands)			
June 30, 2015				
Assets:				
Natural gas swaps	$(15,942)	$ —	$ —	$(15,942)
Interest rate options	$ 41,038	$(36,323)	$ —	$ 4,715
December 31, 2014				
Assets:				
Natural gas swaps	$(18,914)	$ —	$ —	$(18,914)
Interest rate options	$ 53,603	$(49,232)	$ —	$ 4,371

(D) *Investments in Debt and Equity Securities.* Investment securities we hold are classified as available-for-sale. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from other comprehensive margin, except that, in accordance with our rate-making treatment, unrealized gains and losses from investment securities held in the nuclear decommissioning funds are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning funds are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. As of June 30, 2015, approximately 61% of these gross unrealized losses had been unrealized for a duration of less than one year.

The following tables summarize the activities for available-for-sale securities as of June 30, 2015 and December 31, 2014.

June 30, 2015	**Cost**	**Gross Unrealized (dollars in thousands) Gains**	**Losses**	**Fair Value**
Equity	**$225,613**	**$45,528**	**$(3,455)**	**$267,686**
Debt	**178,312**	**1,895**	**(2,328)**	**177,879**
Other	**12,506**	**—**	**(2)**	**12,504**
Total	**$416,431**	**$47,423**	**$(5,785)**	**$458,069**

December 31, 2014	Cost	Gross Unrealized (dollars in thousands) Gains	Losses	Fair Value
Equity	$200,892	$69,536	$ (2,163)	$268,265
Debt	168,182	9,981	(8,619)	169,544
Other	13,927	—	(4)	13,923
Total	$383,001	$79,517	$(10,786)	$451,732

(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. The standard is effective for the annual reporting period beginning after December 15, 2016 using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a modified retrospective approach with the cumulative effect of initially adopting the standard recognized at the date of adoption (which includes additional footnote disclosures). Early adoption is not permitted.

On July 9, 2015, the FASB voted to defer the effective date by one year. Under the amendment, the standard would be effective for annual reporting periods beginning after December 15, 2017 and interim periods therein. The amendment also permits early adoption of the standard, but not before the original effective date of December 15, 2016.

We are currently evaluating the future impact of this standard to our consolidated financial position or results of operations.

In July 2015, the FASB issued "Inventory (Topic 330): Simplifying the Measurement of Inventory." Under the new inventory standard, inventories are required to be measured at the lower of cost and net realizable value, the latter representing the estimated selling price in the ordinary course of business, reduced by costs of completion, disposal, and transportation. Under current guidance, inventories are required to be measured at the lower of cost or market, but depending upon specific circumstances, market could be replacement cost, net realizable value, or net realizable value reduced by a normal profit margin. The amendments do not apply to inventory measured using the last-in, first-out (LIFO) or the retail inventory method. The amendments apply to all other inventory, which includes inventory that is measured using first-in, first out (FIFO) or average cost, the method used to measure all of our inventories. The new standard is effective for us prospectively for annual reporting periods beginning after December 15, 2016, and interim periods therein. Early adoption is permitted as of the beginning of an interim or annual reporting period. We are currently evaluating the future impact of this standard to our consolidated financial position or results of operations.

In April 2015, the FASB issued "Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs". The amendments in this standard require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The amendments in the standard are effective for the financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. We are currently evaluating the impact of adoption on our consolidated financial position or results of operations.

(F) *Accumulated Comprehensive Margin (Deficit).* The table below provides detail of the beginning and ending balance for each classification of other comprehensive margin (deficit) along with the amount of any reclassification adjustments included in margin for each of the periods presented in the unaudited Consolidated Statements of Patronage Capital and Membership Fees and Accumulated Other Comprehensive Margin (Deficit). There were no material changes in the nature, timing or amounts of expected (gain) loss reclassified to net margin from the amounts disclosed in our 2014 Form 10-K. Amounts reclassified to net margin in the table below are reflected in "Other income" on our unaudited Consolidated Statements of Revenues and Expenses.

Our effective tax rate is zero; therefore, all amounts below are presented net of tax.

	Accumulated Other Comprehensive Margin (Deficit) Three Months Ended June 30, 2014
	(dollars in thousands)
	Available-for-sale Securities
Balance at March 31, 2014	$(153)
Unrealized gain	492
(Gain) reclassified to net margin	(61)
Balance at June 30, 2014	$ 278

	Three Months Ended June 30, 2015
	(dollars in thousands)
	Available-for-sale Securities
Balance at March 31, 2015	$ 421
Unrealized loss	(161)
(Gain) reclassified to net margin	(153)
Balance at June 30, 2015	**$ 107**

	Six Months Ended June 30, 2014
	(dollars in thousands)
	Available-for-sale Securities
Balance at December 31, 2013	$(549)
Unrealized gain	881
(Gain) reclassified to net margin	(54)
Balance at June 30, 2014	$ 278

	Six Months Ended June 30, 2015
	(dollars in thousands)
	Available-for-sale Securities
Balance at December 31, 2014	$ 468
Unrealized loss	(54)
(Gain) reclassified to net margin	(307)
Balance at June 30, 2015	**$ 107**

(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.

a. Nuclear Construction

In April 2008, Georgia Power Company, acting for itself and as agent for us, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia (collectively, the Co-owners), and Westinghouse Electric Company LLC and CB&I Stone & Webster, Inc. (formerly known as Stone & Webster, Inc.) (collectively, the Contractor) entered into an engineering, procurement, and construction agreement (the EPC Agreement) to design, engineer, procure, construct and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle Units No. 3 and No. 4).

Under the EPC Agreement for Vogtle Units No. 3 and No. 4, the Co-owners and the Contractor have established both informal and formal dispute resolution procedures in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, has successfully initiated both formal and informal claims through these procedures, including ongoing claims. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and the Co-owners are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

In July 2012, the Co-owners and Contractor began negotiations regarding costs associated with design changes to the Westinghouse AP1000 Design Control Document (DCD) and delays in the project schedule related to the timing of approval of the DCD and issuance of the combined construction permits and operating licenses by the Nuclear Regulatory Commission, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the EPC Agreement. On November 1, 2012, the Co-owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia, seeking a declaratory judgment that the Co-owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Co-owners in the U.S. District Court for the District of Columbia alleging the Co-owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that proper venue is the U.S. District Court for the Southern District of Georgia. In March 2015, the U.S. Court of Appeals for the District of Columbia affirmed the dismissal, which means the case will be tried in the U.S. District Court for the Southern District of Georgia. The portion of the additional costs claimed by the Contractor that would be attributable to us, based on our ownership interest, is approximately $280,000,000 in 2008 dollars, or $390,000,000 in 2015 dollars, with respect to these issues. The Contractor has also asserted that it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Vogtle Units No. 3 and No. 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the lawsuit pending in the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the Nuclear Regulatory Commission have delayed module production and the impacts to the Contractor are recoverable by the Contractor under the EPC Agreement and (ii) the changes to the basemat rebar design required by the Nuclear Regulatory Commission caused additional costs and delays recoverable by the Contractor under the EPC Agreement. The Contractor did not specify amounts relating to these new allegations in its amended counterclaim; however, the Contractor subsequently asserted estimated minimum damages related to the counterclaim, based on our ownership interest, of approximately $75,000,000 in 2014 dollars, or $78,000,000 in 2015 dollars. In June 2015, the Contractor updated its estimated damages under the initial complaint and the amended counterclaim, to an aggregate, based on our ownership interest, of approximately $470,000,000 in 2015 dollars. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. Georgia Power, on behalf of the Co-owners, has not agreed with either the proposed cost or schedule adjustments or that the Co-owners have any responsibility for costs related to these issues. Litigation is ongoing and Georgia Power and the Co-owners intend to vigorously defend their positions. Georgia Power and the Co-owners also expect negotiations with the Contractor to continue with respect to cost and schedule during which time the parties will attempt to reach a mutually acceptable compromise of their positions.

If any or all of these costs are ultimately imposed on the Co-owners, we will capitalize the costs attributable to us. As of June 30, 2015, no material amounts have been recorded related to this claim. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction.

b. Patronage Capital Litigation

On March 13, 2014, a lawsuit was filed in the Superior Court of DeKalb County, Georgia, against us, Georgia Transmission and three of our member distribution cooperatives. Plaintiffs filed an amended complaint on July 28, 2014. The amended complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives and seeks to certify a defendant class of all but one of our 38 members. It was filed by four former consumer-members of four of our members on behalf of themselves and a proposed class of all former consumer-members of our members. Plaintiffs claim that approximately 30% of all the defendants' total allocated patronage capital belongs to former consumer-members. Plaintiffs also allege that patronage capital owed to former consumer-members includes patronage capital allocated by us to our members but not yet distributed to our members. Plaintiffs claim that the patronage capital of former consumer-members held by defendants and the proposed defendant class should be retired immediately when the consumer-members end their membership by terminating service, or alternatively, according to a revolving schedule of no longer than 13 years from the date of its allocation and seek relief to effect such retirements. Plaintiffs further seek to require the defendants to adjust rates in order to establish and maintain reasonable reserves to fund patronage capital retirements on this basis. Plaintiffs also claim that defendants and the proposed defendant class should be required to adopt policies to periodically retire the patronage capital of all consumer-members on a revolving schedule of no longer than 13 years from the date of its allocation. Our first mortgage indenture restricts our ability to distribute patronage capital. Although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level sufficient so that we could comply with the current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiffs' demands would be significant for a period of years.

On August 20, 2014, a second patronage capital lawsuit was filed in the Superior Court of DeKalb County against us, Georgia Transmission, and two of our member distribution cooperatives. The case was filed by two current consumer-members of the two member distribution cooperatives named in the lawsuit. Similar to the above described litigation, this complaint challenges the patronage capital distribution practices of Georgia's electric cooperatives; however, one notable difference is that the first case, described above, seeks to bring claims on behalf of former members while this second case seeks to bring claims on behalf of current members. The plaintiffs allege that the defendants have (i) retained patronage capital for an unreasonably long period of time; (ii) conspired with each other to deprive consumer-members of their patronage capital; and (iii) breached bylaw provisions allegedly requiring that patronage capital be retired when the financial condition of the cooperative will not be impaired. The plaintiffs seek unspecified damages and equitable relief, including an order declaring that the defendants be required to retire patronage capital "according to a regular, reasonable revolving plan." Similarly to the litigation described above, although not expected, if we were ordered by the Court to make distributions of our patronage capital, our first mortgage indenture would require us to raise our rates to a level where we could comply with current patronage capital distribution restrictions, and the rate increases required to meet the Plaintiff's demands could be significant for a period of years. The plaintiffs seek to certify three plaintiffs' classes but do not seek to certify a defendants' class.

We intend to defend vigorously against all claims in the above-described litigation.

c. Environmental Matters

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

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

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

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

(H) *Restricted Cash and Investments.* Restricted cash and investments primarily consist of funds on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted investments will be utilized for future Rural Utilities Service Federal Financing Bank debt service payments. The funds on deposit earn interest at a rate of 5% per annum. At June 30, 2015 and December 31, 2014, we had restricted cash and investments totaling $329,253,000 and $365,585,000, respectively, of which $76,535,000 and $118,390,000, respectively, were classified as long-term.

(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 with our members extending through December 31, 2050. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from our members.

The following regulatory assets and liabilities are reflected on the unaudited consolidated balance sheet as of June 30, 2015 and December 31, 2014.

	2015	2014
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt[(a)]	**$ 66,823**	$ 71,731
Amortization on capital leases[(b)]	**29,041**	27,829
Outage costs[(c)]	**41,616**	45,795
Interest rate swap termination fees[(d)]	**7,350**	9,345
Depreciation expense[(e)]	**46,226**	46,938
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs[(f)]	**35,083**	32,501
Interest rate options cost[(g)]	**98,577**	98,671
Deferral of effects on net margin—Smith Energy Facility[(h)]	**169,188**	128,666
Other regulatory assets[(m)]	**19,122**	22,573
Total Regulatory Assets	**$513,026**	$484,049
Regulatory Liabilities:		
Accumulated retirement costs for other obligations[(i)]	**$ 14,332**	$ 18,559
Deferral of effects on net margin—Hawk Road Energy Facility[(h)]	**28,622**	29,867
Major maintenance reserve[(j)]	**19,133**	23,427
Amortization on capital leases[(b)]	**26,198**	21,693
Deferred debt service adder[(k)]	**71,527**	66,754
Asset retirement obligations[(l)]	**28,277**	28,870
Other regulatory liabilities[(m)]	**4,881**	4,903
Total Regulatory Liabilities	**$192,970**	$194,073
Net Regulatory Assets	**$320,056**	$289,976

(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 30 years.

(b) Represents the difference between lease payments and the aggregate of the amortization on the capital lease assets and the interest on the capital lease obligations for rate-making purposes.

(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 a 24-month period. Nuclear refueling outage costs are amortized on a straight-line basis to expense over the 18 to 24-month operating cycles of each unit.

(d) Represents losses on settled interest rate swap arrangements that are being amortized through 2016 and 2019.

(e) 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.

(f) 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.

(g) Deferral of net loss associated with the change in fair value and expired cost of interest rate options purchased to hedge interest rates on certain borrowings related to Vogtle Units No. 3 and No. 4 construction. 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.

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

(i) Represents difference in timing of recognition of retirement costs associated with long-lived assets in which there are no legal obligations to retire for financial statement purposes and for ratemaking purposes.

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

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

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

(m) The amortization period for other regulatory assets range up to 35 years and the amortization period of other regulatory liabilities range up to 18 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 July 2020, with the majority of the balance scheduled to be credited by the end of 2015.

(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 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 "Federal Financing Bank 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 term loan borrowings through the Federal Financing Bank.

Proceeds of advances made under the Facility will be used to reimburse us for a portion of certain costs of construction relating to Vogtle Units No. 3 and No. 4 that are eligible for financing under the Title XVII Loan Guarantee Program ("Eligible Project Costs"). Aggregate borrowings under the Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) $3,057,069,461, $335,471,604 of which is designated for capitalized interest.

Advances may be requested under the Facility on a quarterly basis through December 31, 2020. On June 12, 2015 we received advances under the Facility totaling $145,000,000. At June 30, 2015, aggregate borrowings totaled $1,036,135,000, including capitalized interest advanced under the loan.

b) *Rural Utilities Service Guaranteed Loans:*

For the six-month period ended June 30, 2015 we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $126,892,000 for general and environmental improvements at existing plants.

In July 2015, we received an additional $18,018,000 in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans for general and environmental improvements at existing plants.

c) *Credit Facilities:*

On March 23, 2015, we entered into a 5-year $1,210,000,000 credit agreement with a syndicate of thirteen lenders, led by the National Rural Utilities Cooperative Finance Corporation as administrative agent.

(L) *Nuclear Fuel Disposal Cost Litigation.* Contracts with the U.S. Department of Energy have been executed to provide for the permanent disposal of spent nuclear fuel produced at Plants Hatch and Vogtle. The Department of Energy failed to begin disposing of spent fuel in January 1998 as required by the contracts, and Georgia Power, as agent for the co-owners of the plants, is pursuing legal remedies against the Department of Energy for breach of contract.

On December 14, 2014, the U.S. Court of Federal Claims issued a judgment in favor of Georgia Power, as agent for the co-owners, to recover spent nuclear fuel storage costs at Hatch and Vogtle Units No. 1 and No. 2 covering the period of January 1, 2005 through December 31, 2010. Our ownership share of the $36,474,000 total award was $10,949,000, which was received in April 2015. The effects of the award were recorded during the first quarter of 2015 and resulted in a $7,320,000 reduction in total operating expenses, including reductions to fuel expense and production costs, as well as a $3,629,000 reduction to plant in service.

(M) *Asset Retirement Obligations.* Asset retirement obligations are legal obligations associated with the retirement of long-lived assets. These obligations represent the present value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The liabilities we have recognized primarily relate to the decommissioning of our nuclear facilities. In addition, we have retirement obligations related to ash ponds, gypsum, landfill sites and asbestos removal. Under the accounting provision for regulated operations, we record a regulatory asset or liability to reflect the difference in timing of recognition of the costs related to nuclear and coal ash related decommissioning for financial statement purposes and for ratemaking purposes.

On April 17, 2015 EPA published its final coal combustion residuals (CCR) rule which regulates CCRs as non-hazardous materials under Subtitle D of the Resource Conservation and Recovery Act. The rule takes effect on October 19, 2015. Based on a preliminary assessment of the impact of the final CCR rule, we revised the forecasted cash flows related to the existing asset retirement obligations and increased the obligations and corresponding assets in electric plant in service by approximately $20,711,000 in the second quarter of 2015. The liabilities are estimates based on various assumptions including, but not limited to, closure and post-closure cost estimates, timing of expenditures, escalation factors, discount rates and methods for complying with the CCR rule. Additional adjustments to the asset retirement obligations are expected periodically as we continue to assess the impact of the rule on our estimates and assumptions.

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 Three and Six Months Ended June 30, 2015 and 2014

Net Margin

Our net margins for the three-month and six-month periods ended June 30, 2015 were $10.8 and $26.2 million compared to $17.2 million and $36.4 million for the same periods of 2014. Through June 30, 2015, we collected approximately 54% of our targeted net margin of $48.5 million for the year ending December 31, 2015. This is typical as our capacity revenues are recorded evenly throughout the year and our management generally budgets conservatively. We anticipate our board of directors will approve a budget adjustment by the end of the year so that net margins will achieve, but not exceed, the targeted margins for interest ratio. 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*" of our 2014 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, and 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 earned by selling electricity to our members, which involves generating or purchasing electricity for our members. Energy revenues recover the variable costs of our business, including fuel, purchased energy and variable operations and maintenance expense.

The components of member revenues for the three-month and six-month periods ended June 30, 2015 and 2014 were as follows:

	Three Months Ended June 30, (dollars in thousands)		2015 vs. 2014 % Change	Six Months Ended June 30, (dollars in thousands)		2015 vs. 2014 % Change
	2015	2014		**2015**	2014	
Capacity revenues	**$ 194,824**	$ 190,077	2.5%	**$ 390,152**	$ 381,752	2.2%
Energy revenues	**116,324**	148,039	(21.4%)	**229,772**	291,123	(21.1%)
Total	**$ 311,148**	$ 338,116	(8.0%)	**$ 619,924**	$ 672,875	(7.9%)
MWh Sales to members	**4,752,295**	5,174,273	(8.2%)	**9,319,984**	10,079,497	(7.5%)
Cents/kWh	**6.55**	6.53	0.2%	**6.65**	6.68	(0.4%)

The decrease in energy revenues from members for the three-month and six-month periods ended June 30, 2015 compared to the same periods in 2014 was primarily due to a decrease in generation for member sales, a decrease in fuel costs and, to a lesser extent, a decrease in purchased power energy. Generation for member sales was somewhat lower during the respective periods as members procured a larger portion of their load requirements from other sources, primarily as a result of lower natural gas prices. Lower member demand for the comparative six-month periods was also partially a result of milder weather experienced during the first quarter of 2015. As a result of the decrease in fuel costs, average energy revenue per kilowatt-hour from sales to members decreased 14.4% and 14.6% for the three-month and six-month periods ended June 30, 2015 as compared to the same periods of 2014. For a discussion of fuel costs and purchased power costs, see "—Operating Expenses."

Sales to Non-members. Our sales to non-members primarily consist of capacity and energy sales at the Smith Energy Facility. Non-members sales increased 82.4% and 26.2% for the three-month and six-month periods ended June 30, 2015 compared to the same periods of 2014 as a result of the relatively lower average cost of power generated at Smith due to lower natural gas prices.

Operating Expenses. Operating expenses decreased 2.1% and 5.5% for the three-month and six-month periods ended June 30, 2015 compared to the same periods of 2014 which was driven primarily by lower fuel costs.

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

	Cost (dollars in thousands)			Generation (MWh)			Cents per kWh		
	Three Months Ended June 30,			Three Months Ended June 30,			Three Months Ended June 30,		
Fuel Source	**2015**	2014	2015 vs. 2014 % Change	**2015**	2014	2015 vs. 2014 % Change	**2015**	2014	2015 vs. 2014 % Change
Coal	**$ 39,317**	$ 63,661	(38.2%)	**1,403,234**	2,017,328	(30.4%)	**2.80**	3.16	(11.2%)
Nuclear	**22,469**	22,000	2.1%	**2,667,554**	2,577,243	3.5%	**0.84**	0.85	(1.3%)
Gas:									
Combined Cycle	**42,300**	41,382	2.2%	**1,583,860**	1,026,369	54.3%	**2.67**	4.03	(33.8%)
Combustion Turbine	**11,125**	6,933	60.5%	**244,634**	96,138	154.5%	**4.55**	7.21	(36.9%)
	$115,211	$133,976	(14.0%)	**5,899,282**	5,717,078	3.2%	**1.95**	2.34	(16.7%)

	Cost (dollars in thousands)			Generation (MWh)			Cents per kWh		
	Six Months Ended June 30,			Six Months Ended June 30,			Six Months Ended June 30,		
Fuel Source	**2015**	2014	2015 vs. 2014 % Change	**2015**	2014	2015 vs. 2014 % Change	**2015**	2014	2015 vs. 2014 % Change
Coal	**$ 81,802**	$120,148	(31.9%)	**2,808,885**	3,913,554	(28.2%)	**2.91**	3.07	(5.1%)
Nuclear(1)	**35,476**	42,766	(17.0%)	**5,045,318**	4,803,209	5.0%	**0.70**	0.89	(21.0%)
Gas:									
Combined Cycle	**89,617**	92,582	(3.2%)	**3,166,827**	2,164,453	46.3%	**2.83**	4.28	(33.8%)
Combustion Turbine	**16,725**	10,756	55.5%	**290,791**	118,766	144.8%	**5.75**	9.06	(36.5%)
	$223,620	$266,252	(16.0%)	**11,311,821**	10,999,982	2.8%	**1.98**	2.42	(18.3%)

(1) The 2015 nuclear fuel cost amount includes a $7.1 million credit for nuclear fuel storage costs recovered as a result of litigation related to responsibility for nuclear disposal costs in the first quarter of 2015. The exclusion of the credit would have resulted in total nuclear fuel costs of $42.5 million, a 0.5% decline and nuclear cost per kWh of 0.84 cents per kWh, a 5.3% decline from the same period of 2014. For information regarding this litigation, see Note L.

The decrease in total fuel costs for the three-month period ended June 30, 2015 compared to the same period of 2014 was primarily due to lower natural gas prices and a shift in the generation mix from the coal-fired units to the relatively more economical natural gas-fired combined cycle units. The decrease in generation at our coal-fired units was attributable in part to extensive testing of environmental controls at Plant Wansley during the first half of 2014, particularly in the second quarter of 2014. In addition, the decrease in total fuel costs for the six-month period ended June 30, 2015 compared to the same period of 2014 was due in part to a decrease in member demand as a result of more moderate weather compared to the extreme cold weather experienced during the first quarter of 2014. During the first quarter of 2015 we also recognized a $7.1 million reduction in fuel expense associated with the recovery of spent nuclear fuel storage costs from the U.S. Department of Energy. For additional information regarding this litigation, see Note L.

Production costs increased 29.7% and 17.4% for the three-month and six-month periods ended June 30, 2015 as compared to the same periods of 2014. The increase resulted primarily from planned major maintenance work at Smith in 2015.

Purchased power costs decreased 22.4% for the six-month period ended June 30, 2015 as compared to the same period of 2014 primarily due to a decrease in energy purchases. This decrease was largely due to decreased demand as a result of more moderate weather during the first quarter of 2015.

Interest charges

Interest expense increased 2.5% and 4.7% for the three-month and six-month periods ended June 30, 2015 as compared to the same periods of 2014 primarily due to increased debt to finance the construction of Vogtle Units No. 3 and No. 4.

Financial Condition

Balance Sheet Analysis as of June 30, 2015

Assets

Cash used for property additions for the six-month period ended June 30, 2015 totaled $256.0 million. Of this amount, approximately $149.5 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, $30.5 million for nuclear fuel purchases and the remaining expenditures were for environmental control systems and normal additions and replacements to existing generation facilities.

Restricted cash and investments consist primarily 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 Rural Utilities Service and Rural Utilities Service-guaranteed Federal Financing Bank notes. Decisions regarding when to apply the funds are guided by the interest rate environment and our anticipated liquidity needs. During the six-month period ended June 30, 2015, deposits and interest earned on these investments totaled $73.3 million. Rural Utilities Service principal and interest payments made utilizing these funds were $109.6 million during the period.

Equity and Liabilities

Accounts payable decreased $55.4 million for the six-month period ended June 30, 2015 primarily as a result of a $45.3 million decrease in the payable to Georgia Power for operation and maintenance costs for our co-owned plants and capital costs associated with Vogtle Units No. 3 and No. 4. Also contributing to the decrease was $17.7 million in credits applied to our members' bills in the first quarter of 2015, for a board approved reduction in 2014 revenue requirements as a result of margin collections in excess of our 2014 target. Offsetting the decrease was a $13.0 million increase in natural gas purchases.

Asset retirement obligations increased $33.3 million primarily due to a $20.7 million change in cash flow estimates associated with the timing of expenditures for future coal ash pond decommissioning costs. The remaining increase relates to the current years' accreted value of all of our asset retirement obligations. For information regarding asset retirements obligations, see Note M.

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4.

We are participating in the construction of two additional nuclear units, Vogtle Units No. 3 and No. 4, and our ownership interest and proportionate share of the cost to construct these units is 30%. As of June 30, 2015, our total investment in the additional Vogtle units was $2.6 billion.

In 2008, Georgia Power, acting for itself and as agent for us, the Municipal Electric Authority of Georgia and the City of Dalton (collectively, the Co-owners) and Westinghouse Electric Company, LLC and Stone & Webster, Inc. (collectively, the Contractor) entered into an Engineering, Procurement and Construction Agreement (the EPC Agreement). Pursuant to the EPC Agreement, the Contractor will design, engineer, procure, construct and test two 1,100 megawatt nuclear units using the Westinghouse AP1000 technology and related facilities at Plant Vogtle, Units No. 3 and No. 4. Under the EPC Agreement, the Co-owners will pay a purchase price that is subject to certain price escalation and adjustments, including fixed escalation amounts and certain index-based adjustments, as well as adjustments for change orders and performance bonuses. The EPC Agreement also provides for liquidated damages upon the Contractor's failure to comply with schedule and performance guarantees. The Contractor's liability for those liquidated damages and for warranty claims is subject to a cap. In addition, the EPC Agreement provides for limited cost sharing by the Co-owners for increases to Contractor costs under certain conditions which have not occurred, with maximum exposure to us of $75 million. Each Co-owner is severally, not jointly, liable to the Contractor for its proportionate share, based on ownership interest, of all amounts owed under the EPC Agreement.

The obligations of Westinghouse and Stone & Webster are guaranteed by their parent companies Toshiba Corporation and The Shaw Group, Inc., a subsidiary of Chicago Bridge & Iron Co. N.V., respectively. In the event that the credit rating of Toshiba is downgraded below investment grade, Westinghouse would be required to provide a letter of credit or other credit enhancement to the Co-owners. In the event that any Co-owner's credit rating is downgraded below investment grade, that Co-owner would be required to provide a letter of credit or other credit enhancement to the Contractor. In addition, the Co-owners may terminate the EPC Agreement at any time for their convenience, provided that the Co-owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Contractor. The Contractor may also terminate the EPC Agreement under certain circumstances, including certain suspension or delays of work by the Co-owners, action by a governmental authority to stop work permanently, certain breaches of the EPC Agreement by the Co-owners, Co-owner insolvency and certain other events. As agent for the Co-owners, Georgia Power has designated Southern Nuclear Operating Company as its agent for contract management.

The Nuclear Regulatory Commission certified the Westinghouse AP1000 Design Control Document (DCD) effective December 30, 2011. On February 10, 2012, the Nuclear Regulatory Commission issued combined licenses for Vogtle Units No. 3 and No. 4 which allowed full construction to begin. 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 levels, and additional challenges may arise as construction proceeds.

The Co-owners and the Contractor have established both informal and formal dispute resolution procedures in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, has successfully initiated both formal and informal claims through these procedures, including ongoing claims. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and the Co-owners are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

In July 2012, the Co-owners and Contractor began negotiations regarding costs associated with design changes to the DCD and delays in the project schedule related to the timing of approval of the DCD and issuance of the combined construction permits and operating licenses by the Nuclear Regulatory Commission, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the EPC Agreement. On November 1, 2012, the Co-owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia, seeking a declaratory judgment that the Co-owners are not responsible for these costs. Also on November 1, 2012, the Contractor filed suit against the Co-owners in the U.S. District Court for the District of Columbia alleging the Co-owners are responsible for these costs. In August 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that proper venue is the U.S. District Court for the Southern District of Georgia. In March 2015, the U.S. Court of Appeals for the District of Columbia affirmed the dismissal, which means the case will be tried in the U.S. District Court for the Southern District of Georgia. The portion of the additional costs claimed by the Contractor that would be attributable to us, based on our ownership interest, is approximately $280 million in 2008 dollars, or $390 million in 2015 dollars, with respect to these issues. The Contractor has also asserted that it is entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Vogtle Units No. 3 and No. 4, respectively. On May 22, 2014, the Contractor filed an amended counterclaim to the lawsuit pending in the Southern District of Georgia alleging that (i) the design changes to the DCD imposed by the Nuclear Regulatory Commission have delayed module production and the impacts to the Contractor are recoverable by the Contractor under the EPC Agreement and (ii) the changes to the basemat rebar design required by the Nuclear Regulatory Commission caused additional costs and delays recoverable by the Contractor under the EPC Agreement. The Contractor did not specify amounts relating to these new allegations in its amended counterclaim; however, the Contractor subsequently asserted estimated minimum damages related to the counterclaim, based on our ownership interest, of approximately $75 million in 2014 dollars, or $78 million in 2015 dollars. In June 2015, the Contractor updated its estimated damages under the initial complaint and the amended counterclaim to an aggregate, based on our ownership interest, of approximately $470 million in 2015 dollars. The Contractor may from time to time continue to assert that it is entitled to additional payments with respect to these allegations, any of which could be substantial. Georgia Power, on behalf of the Co-owners, has not agreed with either the proposed cost or schedule adjustments or that the Co-owners have any responsibility for costs related to these issues. Litigation is ongoing and Georgia Power and the Co-owners intend to vigorously defend their positions. Georgia Power and the Co-owners also expect negotiations with the Contractor to continue with respect to cost and schedule during which time the parties will attempt to reach a mutually acceptable compromise of their positions.

In January 2015, the Contractor notified the Co-owners, through Georgia Power, of the Contractor's proposed revised integrated project schedule for completion of Vogtle Units No. 3 and No. 4 which would delay the estimated in-service dates to the second quarter of 2019 and the second quarter of 2020, respectively, as a result of the Contractor's inability to overcome certain identified schedule challenges. This represents an 18-month delay for each unit from the previously disclosed schedule which projected in-service dates for Vogtle Units No. 3 and No. 4 in the fourth quarter of 2017 and the fourth quarter of 2018, respectively. Georgia Power, on behalf of the Co-owners, has not agreed to any changes to the guaranteed substantial completion dates of April 2016 and April 2017 for Vogtle Units No. 3 and No. 4, respectively.

In addition, we and Georgia Power believe that, pursuant to the EPC Agreement, the Contractor is responsible for the Contractor's costs related to the Contractor's delay (including any related construction and mitigation costs, which could be significant) and that the Co-owners are entitled to recover liquidated damages for the Contractor's delay beyond the guaranteed substantial completion dates of April 2016 and April 2017. Consistent with the Contractor's position in the pending litigation described above, we and Georgia Power expect the Contractor to contest any claims for liquidated damages and to assert that the Co-owners are responsible for additional costs related to the Contractor's delay.

During the extended construction period, we will continue to incur our share of owner-related costs, including property taxes, oversight costs, compliance costs, and other operational readiness costs and will also continue to incur financing costs. Although Georgia Power, on behalf of the Co-owners, has not accepted the revised schedule, we expect that each additional month delay beyond the previously disclosed in-service dates for Vogtle Units No. 3 and No. 4 of the fourth quarter of 2017 and the fourth quarter of 2018, respectively, will increase our previously disclosed project budget, which includes capital costs, allowance for funds used during construction and a contingency amount, of $4.5 billion by approximately $28 million per month, which would increase our project budget to $5.0 billion should the entire eighteen-month delay be realized. We anticipate that our members will be able to utilize the generating capacity that currently exists in the region and secure sufficient amounts of economically priced energy to replace what they otherwise would have obtained from Vogtle Units No. 3 and No. 4 through the announced delay period.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the combined 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 issues are expected to arise as construction proceeds, 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 Contractor, or both.

In addition, as construction continues, risk remains that ongoing challenges with the Contractor's performance including additional challenges in its fabrication, assembly, delivery, and installation of the shield building and structural modules could further delay the revised forecasted completion dates and the Contractor must improve its schedule performance in order to mitigate this risk. Also, delays in the receipt of the remaining permits necessary for the operation of Vogtle Units No. 3 and No. 4 or other issues could arise and may further impact the project schedule and cost. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are also likely to arise throughout construction. Any of these claims or disputes may be resolved through formal and informal dispute resolution procedures under the EPC Agreement but also may be resolved through litigation.

The ultimate outcome of these matters cannot be determined at this time. See "RISK FACTORS" in our 2014 Form 10-K for a discussion of certain risks associated with the licensing, construction, financing and operation of nuclear generating units. For additional information see "*—Financing Activities—Department of Energy-Guaranteed Loan*" and Note K.

Environmental Regulations

Litigation and federal rulemakings continue to affect operations at our facilities. Following are some of the more recent substantial developments that have occurred during 2015.

On August 3, 2015, the U.S. Environmental Protection Agency (EPA) released final rules regarding emissions of carbon dioxide (CO_2) from certain fossil fuel-fired electric generating units. One of the rules limits emissions from new, modified and reconstructed units while another establishes guidelines for states to develop plans to limit emissions of CO_2 from existing units. This latter rule's goal is a 32% reduction in CO_2 emissions from 2005 levels nationwide in 2030 and thereafter with specified interim emission rates phasing in between 2022 and 2029. For Georgia, this rule requires a 34% reduction in emission rates from 2012 levels by 2030, with over 50% of that reduction slated to occur between 2022 and 2024. EPA also proposed a federal plan that would be implemented should states fail to submit acceptable plans as well as a model rule that states could use in developing their plans. These guidelines and standards could result in future operational restrictions on our coal-fired units and substantial compliance costs, but, unlike the proposed rule, the final rule provides that nuclear generating units that are currently under construction, such as Vogtle Units No. 3 and No. 4, will be credited towards the required reduction targets. We are in the early stages of reviewing these rules and cannot determine their ultimate impacts or the results of anticipated legal challenges at this time.

On June 29, 2015, the U.S. Supreme Court ruled that the EPA acted unreasonably by failing to consider costs when promulgating the Mercury and Air Toxics Standards (MATS) rule, which establishes maximum achievable control technology limits for certain hazardous air pollutants at coal and oil-fired electric generating units. As a result, the Court reversed an earlier decision from the U.S. Court of Appeals for the District of Columbia Circuit that had upheld the MATS rule, remanding the case back to the D.C. Circuit for further action. Significantly, the MATS rule remains effective, pending subsequent action by the D.C. Circuit. Our affected generating units—which include our co-owned units at Plants Scherer and Wansley—will have until April 16, 2016 to comply, having been granted compliance extensions of up to one year by the Georgia Environmental Protection Division. The necessary controls are already in place at both plants and are being prepared to meet that compliance deadline.

On June 12, 2015, EPA published a final rule that requires certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down or malfunction (SSM). In the rule, EPA has determined that 34 states, including Georgia, have SSM provisions in their SIPs that do not meet the requirements of the Clean Air Act and must be revised and submitted to EPA for approval by November 22, 2016. This new rule may result in significant additional compliance and operational costs at our power plants, and may result in future litigation alleging failure to meet emission limitations that previously did not apply to our facilities during times of SSM, provided that certain work practice standards were being met. We cannot predict the extent of such possible litigation, nor can we predict the ultimate outcome of this rulemaking, including any resulting state rulemakings, revisions to the Georgia SIP and any ensuing challenges that may be brought against the EPA final rule or any resulting state rules.

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a rule that revises the regulatory definition of waters of the U.S. for all Clean Water Act programs, significantly expanding the scope of federal jurisdiction. Although the rule is not expected to have a substantial impact on our existing operations, it will likely increase permitting and regulatory requirements and costs associated with the siting and permitting of new facilities. The ultimate impact of the rule will depend on the outcome of legal challenges and cannot be determined at this time.

On April 17, 2015 EPA published its final coal combustion residuals (CCR) rule, in which it decided to regulate CCRs as non-hazardous material under Subtitle D of the Resource Conservation and Recovery Act. The final rule contains requirements for structural integrity assessments, groundwater monitoring, location siting, composite lining, inactive units, closure and post closure, beneficial use recycling, design and operating criteria, recordkeeping, notification, and internet posting for new and existing CCR landfills, CCR surface impoundments and lateral expansions of CCR facilities. The rule takes effect on October 19, 2015. We are still reviewing the effects of the CCR, but they could include actions to address some or all of the requirements listed above. Significant operational changes for existing CCR storage units, extended plant outages, construction of lined landfills and groundwater monitoring facilities and additional material management and financial assurance requirements may be needed. Preliminary estimates suggest that our capital costs for compliance with the CCR (in combination with EPA's proposed effluent limitations guidelines rule which is to be finalized by September 2015) could be approximately $200 million. More definitive cost estimates will be developed as the process of rule evaluation, compliance approach design and construction implementation proceeds, and the ultimate impacts associated with the CCR rule cannot be determined with certainty at this time.

In connection with the CCR rule, we recorded increases to existing asset retirement obligations in the second quarter of 2015 based on a preliminary assessment of the impact of the final CCR rule.

Additional adjustments to the asset retirement obligations are expected periodically as we continue to assess the impact of the rule on the estimated costs, timing of expenditures and other assumptions. See Note M for additional information regarding asset retirement obligations.

For further 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 2014 Form 10-K.

Liquidity

At June 30, 2015, we had $1.4 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $287 million in cash and cash equivalents and $1.1 billion of unused and available committed credit arrangements.

At June 30, 2015, we had in excess of $1.6 billion of committed credit arrangements in place and $1.1 billion available under these facilities. These four separate facilities are reflected in the table below:

Committed Credit Facilities

	Authorized Amount	Available June 30, 2015	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit led by CFC	$1,210[1]	$812[2]	March 2020
CFC Line of Credit[3]	110	110	December 2018
JPMorgan Chase Line of Credit	150	34[4]	November 2016
Secured Facilities:			
CFC Term Loan[3]	250	250	December 2018

(1) The amount of this facility that can be used to support outstanding commercial paper is limited to $1.0 billion.

(2) Of the portion of this facility that was unavailable at June 30, 2015, $262 million was dedicated to support outstanding commercial paper and $136 million was related to letters of credit issued to support variable rate demand bonds.

(3) Any amounts drawn under the $110 million unsecured line of credit with CFC can be converted to a long-term borrowing under the $250 million term loan with CFC that is secured under the first mortgage indenture, with a maturity no later than December 31, 2043. The maximum amount that can be drawn under the two CFC facilities combined is $250 million; therefore, any amounts drawn under the $110 million unsecured line of credit will reduce the amount that can be drawn under the $250 million secured term loan.

(4) Of the portion of this facility that was unavailable at June 30, 2015, $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.

As of June 30, 2015, we were using our commercial paper program to provide interim funding for 1) payments related to the construction of Vogtle Units No. 3 and No. 4 prior to receiving advances of permanent funding under the Department of Energy-guaranteed Federal Financing Bank loan, which can be requested no more frequently than quarterly and 2) the premium payments made in connection with our interest rate hedging program. Between our credit arrangements and projected cash on hand, we believe we have sufficient liquidity to cover our normal operations and to provide for the interim financings described above.

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.

Under our unsecured committed lines of credit, we have the ability to issue letters of credit totaling $760 million in the aggregate, of which $508 million remained available at June 30, 2015. 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 minimum levels of patronage capital. At June 30, 2015, the required minimum level was $675 million and our actual patronage capital was $787 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 June 30, 2015, we had $7.6 billion of secured indebtedness and $262 million of unsecured indebtedness outstanding.

At June 30, 2015, we had $329 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 June 30, 2015—*Assets*" for more information regarding this account.

Financing Activities

First Mortgage Indenture. At June 30, 2015, we had $7.5 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 2014 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. At June 30, 2015 we had three approved Rural Utilities Service-guaranteed loans being funded through the Federal Financing Bank that are in various stages of being drawn down. These three loans totaled $561 million with $194 million remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture. As of June 30, 2015, we had $2.6 billion of debt outstanding under various Rural Utilities Service-guaranteed loans.

Department of Energy-Guaranteed Loan. In February 2014, we closed on a loan with the Department of Energy that will fund up to the lesser of $3.057 billion or 70% of eligible project costs related to the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. This loan is being funded by the Federal Financing Bank and is backed by a federal loan guarantee provided by the Department of Energy.

As of June 30, 2015, our total investment in Vogtle Units No. 3 and No. 4 was $2.6 billion and we have incurred $2.4 billion of debt to provide long-term financing for this investment. This long-term debt includes $1.4 billion of taxable first mortgage bonds we previously issued and $1.0 billion, including capitalized interest, under the Department of Energy loan facility. The facility may be used until no later than December 2020 to provide long-term funding for up to 70% of eligible project costs after they are incurred. As of June 30, 2015, we have the capacity to fund an additional $642 million under the facility based on the amount of eligible project costs we have incurred to date. We anticipate making draws on at least a semi-annual basis to meet our funding requirements as construction progresses. When advanced, the debt will be secured under our first mortgage indenture. For additional information regarding this loan, see Note K.

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 2014 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 2014 Form 10-K.

Item 4. Controls and Procedures

As of June 30, 2015, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

There have been no changes in internal control over financial reporting or other factors that occurred during the quarter ended June 30, 2015 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 not been any material changes to legal proceedings from those reported in "Item 3—LEGAL PROCEEDINGS" of our 2014 Form 10-K.

Item 1A. Risk Factors

There have been no material changes from the risks disclosed in "Item 1A—RISK FACTORS" of our 2014 Form 10-K.

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

Not Applicable.

Item 3. Defaults upon Senior Securities

Not Applicable.

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

Not Applicable.

Item 6. Exhibits

Number	Description
4.1	Seventieth Supplemental Indenture, dated as of May 27, 2015, made by Oglethorpe to U.S. Bank National Association, as trustee, relating to Amendment of the Series 2011 (FFB W-8) Note.
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: August 12, 2015

By: /s/ Michael L. Smith

Michael L. Smith
President and Chief Executive Officer

Date: August 12, 2015

/s/ Elizabeth B. Higgins

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