UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

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

Oglethorpe Power Corporation

(An Electric Membership Corporation)
(Exact name of registrant as specified in its charter)

Georgia (State or other jurisdiction of incorporation or organization)	**58-1211925** (I.R.S. employer identification no.)
2100 East Exchange Place **Tucker, Georgia** (Address of principal executive offices)	**30084-5336** (Zip Code)

Registrant's telephone number, including area code **(770) 270-7600**

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

Indicate by check mark whether the registrant has submitted electronically 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
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FOR THE QUARTER ENDED SEPTEMBER 30, 2013

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CAUTIONARY STATEMENTS REGARDING

FORWARD-LOOKING STATEMENTS AND ASSOCIATED RISKS

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 the heading "RISK FACTORS" and in other sections of our Annual Report on Form 10-K for the fiscal year ended December 31, 2012. 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 construction projects, including the construction of two additional nuclear units at Plant Vogtle;
- legislative and regulatory compliance standards and our ability to comply with any applicable standards, including mandatory reliability standards, and potential penalties for non-compliance;
- costs associated with achieving and maintaining compliance with applicable environmental laws and regulations, including those related to air emissions, water and coal combustion byproducts;
- potential legislative and regulatory responses to climate change initiatives, including the regulation of carbon dioxide and other greenhouse gas emissions;
- 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 the availability of funding from the U.S. Department of Energy and other government sources;
- 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;
- weather conditions and other natural phenomena;
- 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;
- 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 or our competitors;
- general economic conditions;
- 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;
- litigation or legal and administrative proceedings and settlements;
- 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
Condensed Balance Sheets (Unaudited)
September 30, 2013 and December 31, 2012

	(dollars in thousands)	
	2013	2012
Assets		
Electric plant:		
In service	**$ 7,860,834**	$ 7,506,707
Less: Accumulated provision for depreciation	**(3,581,212)**	(3,472,087)
	4,279,622	4,034,620
Nuclear fuel, at amortized cost	**311,355**	321,196
Construction work in progress	**2,261,374**	2,240,920
	6,852,351	6,596,736
Investments and funds:		
Nuclear decommissioning trust fund	**325,924**	300,785
Deposit on Rocky Mountain transactions	**15,128**	14,392
Investment in associated companies	**62,720**	60,770
Long-term investments	**78,353**	77,022
Restricted cash	**31,064**	8,953
Other	**472**	1,084
	513,661	463,006
Current assets:		
Cash and cash equivalents	**436,639**	298,565
Restricted short-term investments	**254,854**	64,671
Receivables	**136,973**	134,896
Inventories, at average cost	**277,633**	263,949
Prepayments and other current assets	**16,310**	16,073
	1,122,409	778,154
Deferred charges:		
Deferred debt expense, being amortized	**63,808**	63,210
Regulatory assets	**339,274**	352,902
Other	**43,818**	60,558
	446,900	476,670
	$ 8,935,321	$ 8,314,566

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

Oglethorpe Power Corporation
Condensed Balance Sheets (Unaudited)
September 30, 2013 and December 31, 2012

	(dollars in thousands)	
	2013	2012
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 739,639**	$ 673,009
Accumulated other comprehensive (deficit) margin	**(194)**	903
	739,445	673,912
Long-term debt	**6,076,645**	5,784,130
Obligation under capital leases	**126,187**	135,943
Obligation under Rocky Mountain transactions	**15,128**	14,392
	6,957,405	6,608,377
Current liabilities:		
Long-term debt and capital leases due within one year	**447,388**	168,393
Short-term borrowings	**603,812**	569,480
Accounts payable	**82,790**	145,451
Accrued interest	**49,357**	58,649
Accrued and withheld taxes	**24,482**	4,881
Member power bill prepayments, current	**75,410**	65,079
Other current liabilities	**14,960**	19,539
	1,298,199	1,031,472
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**22,528**	23,638
Asset retirement obligations	**394,724**	381,362
Member power bill prepayments, non-current	**32,613**	40,853
Power sale agreement, being amortized	**29,669**	40,355
Regulatory liabilities	**139,187**	129,985
Other	**60,996**	58,524
	679,717	674,717
	$8,935,321	$8,314,566

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

Oglethorpe Power Corporation
Condensed Statements of Revenues and Expenses (Unaudited)
For the Three and Nine Months Ended September 30, 2013 and 2012

	(dollars in thousands)			
	Three Months		Nine Months	
	2013	2012	**2013**	2012
Operating revenues:				
Sales to Members	**$315,646**	$338,768	**$908,490**	$ 944,481
Sales to non-Members	**34,079**	38,628	**71,498**	99,842
Total operating revenues	**349,725**	377,396	**979,988**	1,044,323
Operating expenses:				
Fuel	**138,252**	171,178	**351,467**	419,594
Production	**88,689**	91,753	**272,703**	280,096
Depreciation and amortization	**40,779**	37,789	**116,440**	122,889
Purchased power	**12,989**	11,396	**40,373**	35,332
Accretion	**5,755**	4,884	**17,062**	14,599
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(7,005)**	(655)	**(25,672)**	(15,214)
Total operating expenses	**279,459**	316,345	**772,373**	857,296
Operating margin	**70,266**	61,051	**207,615**	187,027
Other income:				
Investment income	**8,353**	6,435	**23,778**	22,450
Gain on termination of Rocky Mountain transactions	**—**	14,719	**—**	14,719
Other	**2,317**	2,591	**6,834**	9,490
Total other income	**10,670**	23,745	**30,612**	46,659
Interest charges:				
Interest expense	**80,569**	76,443	**232,597**	231,290
Allowance for debt funds used during construction	**(23,597)**	(21,151)	**(73,013)**	(61,588)
Amortization of debt discount and expense	**3,860**	5,761	**12,013**	15,843
Net interest charges	**60,832**	61,053	**171,597**	185,545
Net margin	**$ 20,104**	$ 23,743	**$ 66,630**	$ 48,141

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

Oglethorpe Power Corporation
Condensed Statements of Comprehensive Margin (Unaudited)
For the Three and Nine Months Ended September 30, 2013 and 2012

	(dollars in thousands)			
	Three Months		Nine Months	
	2013	2012	**2013**	2012
Net margin	**$20,104**	$23,743	**$66,630**	$48,141
Other comprehensive margin:				
Unrealized (loss) gain on available-for-sale securities	**205**	42	**(1,097)**	870
Total comprehensive margin	**$20,309**	$23,785	**$65,533**	$49,011

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

Oglethorpe Power Corporation
Condensed Statements of Patronage Capital and Membership Fees
and Accumulated Other Comprehensive Margin (Deficit) (Unaudited)
For the Nine Months Ended September 30, 2013 and 2012

(dollars in thousands)

	Patronage Capital and Membership Fees	**Accumulated Other Comprehensive Margin (Deficit)**	**Total**
Balance at December 31, 2011	$633,689	$ 618	$634,307
Components of comprehensive margin:			
Net margin	48,141	—	48,141
Unrealized gain on available-for-sale securities	—	870	870
Balance at September 30, 2012	$681,830	$ 1,488	$683,318
Balance at December 31, 2012	$673,009	$ 903	$673,912
Components of comprehensive margin:			
Net margin	66,630	—	66,630
Unrealized loss on available-for-sale securities	—	(1,097)	(1,097)
Balance at September 30, 2013	**$739,639**	**$ (194)**	**$739,445**

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

Oglethorpe Power Corporation
Condensed Statements of Cash Flows (Unaudited)
For the Nine Months Ended September 30, 2013 and 2012

	(dollars in thousands)	
	2013	2012
Cash flows from operating activities:		
Net margin	**$ 66,630**	$ 48,141
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**218,425**	229,787
Accretion cost	**17,062**	14,599
Amortization of deferred gains	**(1,341)**	(35,579)
Allowance for equity funds used during construction	**(1,938)**	(2,123)
Deferred outage costs	**(33,347)**	(22,583)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(25,672)**	(15,214)
Gain on sale of investments	**(21,694)**	(8,001)
Regulatory deferral of costs associated with nuclear decommissioning	**10,652**	(528)
Other	**(5,416)**	(6,321)
Change in operating assets and liabilities:		
Receivables	**(2,995)**	(8,742)
Inventories	**(13,684)**	11,609
Prepayments and other current assets	**(234)**	206
Accounts payable	**(76,892)**	(54,392)
Accrued interest	**(9,292)**	(20,080)
Accrued taxes	**19,601**	3,930
Other current liabilities	**(4,264)**	(3,888)
Member power bill prepayments	**2,091**	12,227
Total adjustments	**71,062**	94,907
Net cash provided by operating activities	**137,692**	143,048
Cash flows from investing activities:		
Property additions	**(414,493)**	(495,925)
Activity in decommissioning fund—Purchases	**(479,622)**	(536,224)
—Proceeds	**475,446**	532,041
(Increase) decrease in restricted cash	**(22,111)**	35,714
(Increase) decrease in restricted short-term investments	**(190,184)**	42,808
Activity in other long-term investments—Purchases	**(34,510)**	(4,404)
—Proceeds	**36,753**	13,689
Activity on interest rate options—Collateral returned	**(146,730)**	(43,070)
—Collateral received	**168,840**	7,810
Other	**11,563**	(17,198)
Net cash used in investing activities	**(595,048)**	(464,759)
Cash flows from financing activities:		
Long-term debt proceeds	**875,640**	108,792
Long-term debt payments	**(313,983)**	(94,706)
Increase in short-term borrowings, net	**34,332**	296,222
Other	**(559)**	5,542
Net cash provided by financing activities	**595,430**	315,850
Net increase (decrease) in cash and cash equivalents	**138,074**	(5,861)
Cash and cash equivalents at beginning of period	**298,565**	443,671
Cash and cash equivalents at end of period	**$ 436,639**	$ 437,810
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 165,388**	$ 181,675
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	**$ 19,488**	$ (13,069)

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

Oglethorpe Power Corporation
Notes to Unaudited Condensed Financial Statements
For the Three and Nine Months ended September 30, 2013 and 2012

(A) *General.* The condensed 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- and nine-month periods ended September 30, 2013 and 2012. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to SEC rules and regulations, although we believe that the disclosures are adequate to make the information presented not misleading. Certain prior year amounts have been reclassified to conform with the current year presentation. These condensed 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, 2012, as filed with the SEC. The results of operations for the three- and nine-month periods ended September 30, 2013 are not necessarily indicative of results to be expected for the full year. As noted in our 2012 Form 10-K, our revenues consist primarily of sales to our 38 electric distribution cooperative members and, thus, the receivables on the condensed balance sheets are principally from our members. (See "Notes to Financial Statements" in our 2012 Form 10-K.)

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

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

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

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

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

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

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

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

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

The tables below detail assets and liabilities measured at fair value on a recurring basis at September 30, 2013 and December 31, 2012.

		Fair Value Measurements at Reporting Date Using		
	September 30, 2013	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	**$131,348**	$131,348	$ —	$ —
International equity	**67,142**	67,142	—	—
Corporate bonds	**37,334**	—	37,334	—
US Treasury and government agency securities	**48,013**	48,013	—	—
Agency mortgage and asset backed securities	**28,594**	—	28,594	—
Municipal Bonds	**634**	—	634	—
Other	**12,859**	12,859	—	—
Long-term investments:				
Corporate bonds	**6,383**	—	6,383	—
US Treasury and government agency securities	**8,518**	8,518	—	—
Agency mortgage and asset backed securities	**3,947**	—	3,947	—
International equity	**10,327**	10,327	—	—
Mutual funds	**49,028**	49,028	—	—
Other	**150**	150	—	—
Interest rate options	**43,531**	—	—	43,531(1)
Natural gas swaps	**(197)**	—	(197)	—

	December 31, 2012	Fair Value Measurements at Reporting Date Using		
		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	$118,329	$118,329	$ —	$ —
International equity	48,105	48,105	—	—
Corporate bonds	53,172	—	53,172	—
US Treasury and government agency securities	46,626	46,626	—	—
Agency mortgage and asset backed securities	21,273	—	21,273	—
Other	13,280	13,280	—	—
Long-term investments:				
Corporate bonds	5,762	—	5,762	—
US Treasury and government agency securities	7,387	7,387	—	—
Agency mortgage and asset backed securities	2,526	—	2,526	—
Mutual funds	60,972	60,972	—	—
Other	375	375	—	—
Bond, reserve and construction funds	1	1	—	—
Interest rate options	25,783	—	—	25,783[1]
Natural gas swaps	(1,085)	—	(1,085)	—

(1) Interest rate options as reflected on the unaudited condensed Balance Sheet include the fair value of the interest rate options offset by $31,060,000 and $8,950,000 of collateral received from the counterparties at September 30, 2013 and December 31, 2012, respectively.

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 following tables present the changes in our Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2013 and 2012.

	Three Months Ended September 30, 2013
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at June 30, 2013	$43,680
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(149)
Balance at September 30, 2013	**$43,531**

	Three Months Ended September 30, 2012
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at June 30, 2012	$39,215
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(9,294)
Balance at September 30, 2012	$29,921

	Nine Months Ended September 30, 2013
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at December 31, 2012	$25,783
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	17,748
Balance at September 30, 2013	**$43,531**

	Nine Months Ended September 30, 2012		
	Decommissioning funds	Long-term investments	Interest Rate Options
	(dollars in thousands)		
Assets (Liabilities):			
Balance at December 31, 2011	$(982)	$ 7,713	$ 69,446
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets)	982	—	(39,525)
Impairment included in other comprehensive margin (deficit)	—	887	—
Liquidations	—	(8,600)	—
Balance at September 30, 2012	$ —	$ —	$ 29,921

The estimated fair values of our long-term debt, including current maturities at September 30, 2013 and December 31, 2012 were as follows (in thousands):

	2013		2012	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$6,509,240**	**$7,065,111**	$5,930,449	$7,213,365

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 the 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. We also have small amounts of long-term debt provided by National Rural Utilities Cooperative Finance Corporation (CFC) and by CoBank, ACB in addition to a multi-year term loan with Bank of Tokyo. The valuations for the first mortgage bonds and the pollution control revenue bonds were obtained from a third party subscription service and are based on secondary market trading of our debt. Valuations for debt issued by the Federal Financing Bank are based on U.S. Treasury rates as of September 30, 2013 plus 1/8 percent, which reflects our borrowing rate for new loans of this type from the Federal Financing Bank. We use an interest rate quote sheet provided by CoBank for valuation of the CoBank debt, which reflects current rates for a similar loan. The rates on the CFC debt are fixed and the valuation is based on rate quotes provided by CFC. The rate in effect at September 30, 2013 for our term loan, which resets each month and is based on a spread to LIBOR, was used for valuation of the term loan.

We use the methods and assumptions described above to estimate the fair value of each class of financial instruments. 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. Prior to December 2012, our commodity trading derivatives were designated as hedging instruments under authoritative guidance for accounting for derivatives and hedging. In December 2012, we discontinued hedge accounting for these derivatives and began applying regulatory accounting. Consistent with our rate-making, unrealized gains or losses on natural gas swaps are reflected as a regulatory asset or liability. To hedge 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, we have entered into interest rate options. Hedge accounting is not applied to our interest rate options. Consistent with our rate-making, unrealized losses from the interest rate options are recorded as a regulatory asset. Within our nuclear decommissioning trust fund, derivatives including options, swaps and credit default swaps, which are non-speculative, could be utilized to mitigate volatility associated with duration, default, yield curve and the interest rate risks of the portfolio. Consistent with our rate-making, unrealized gains or losses related to the decommissioning trust funds are recorded as an increase or decrease in the associated regulatory asset or liability. We do not hold or enter into derivative transactions for trading or speculative purposes.

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 September 30, 2013, 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 the natural gas swap arrangements, we pay the counterparty a fixed price for specified natural gas quantities and receive a payment for such quantities based on a market price index. These payment obligations are netted, such that if the market price index is lower than the fixed price, we will make a net payment, and if the market price index is higher than the fixed price, we will receive a net payment.

At September 30, 2013 and December 31, 2012, the estimated fair values of our natural gas contracts were net liabilities of approximately $197,000 and $1,085,000, respectively.

As of September 30, 2013 and December 31, 2012, neither we nor any counterparties were required to post credit support or collateral under the natural gas swap agreements. If the credit-risk-related contingent features underlying these agreements had been triggered on September 30, 2013 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit totaling up to $278,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of September 30, 2013 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2013	0.3
2014	3.7
2015	0.3
Total	**4.3**

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 to hedge the interest rates on approximately $2.2 billion of the expected debt that will be used to finance two additional nuclear units at Plant Vogtle. As of September 30, 2013, our outstanding swaptions hedged approximately $1.6 billion of the expected debt for the new Vogtle units.

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 are in the range of 50 to 100 basis points above LIBOR swap rates that were in effect as of September 30, 2013 and the weighted average fixed rate is 4.16%. Swaptions having notional amounts totaling $562,894,000 expired without value during the nine months ended September 30, 2013. 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 and have no additional payment obligations. These derivatives are recorded at fair value, and hedge accounting is not applied. At September 30, 2013 and December 31, 2012, the fair value of these swaptions was approximately $43,531,000 and $25,783,000, 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 September 30, 2013 and December 31, 2012, we held $31,060,000 and $8,950,000 of funds posted as collateral by the counterparties, respectively. The collateral received is recorded as restricted cash on our balance sheet. The liability associated with the collateral is recorded as an offset to the fair values of the swaptions, which are recorded within other deferred charges on the balance sheet, resulting in a net carrying amount of the interest rate options of $12,471,000 and $16,833,000 at September 30, 2013 and December 31, 2012, respectively.

We are deferring 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 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 $2.2 billion of debt that we hedged with the swaptions.

We estimate the value of the LIBOR swaptions utilizing an option pricing model based on several inputs including the notional amount, the forward LIBOR swap rates, the option volatility, the fixed rate on the underlying swap, the time to expiration, the term of the underlying swap and discount rates, as well as credit attributes, including the credit spread of the counterparty and the amount of credit support that is available for each swaption. The fair value of the swaptions is sensitive to certain of these inputs, especially option volatility. We are able to effectively observe all of these factors using a variety of market sources except for the credit spreads of certain counterparties and the option volatility. We are able to estimate option volatility implied by valuations we obtain from various sources, but the valuations, and therefore the implied option volatilities, vary considerably from one source to another. Since valuations of comparable instruments are generally not publicly available, we have categorized these LIBOR swaptions as Level 3. We considered both any intrinsic value and the remaining time value associated with the derivatives and considered counterparty credit risk in our determination of all estimated fair values. 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. The following table reflects the remaining notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of September 30, 2013.

Year	**LIBOR Swaption Notional Dollar Amount** (in thousands)
2013	$ 191,559
2014	563,425
2015	470,625
2016	310,533
2017	80,169
Total	**$1,616,311**

The table below reflects the fair value of derivative instruments and their effect on our condensed balance sheets at September 30, 2013 and December 31, 2012.

	Balance Sheet Location	**Fair Value**	
		2013	2012
		(dollars in thousands)	
Not designated as hedges:			
Assets:			
Interest rate options[(1)]	Other deferred charges	**$43,531**	$25,783
Liabilities:			
Natural gas swaps	Other current liabilities	**$ 197**	$ 1,085

(1) Excludes liability associated with cash collateral of $31,060,000 and $8,950,000 as of September 30, 2013 and December 31, 2012, respectively, which is recorded as an offset to the fair value of the swaptions on the unaudited condensed balance sheets.

The following table presents the gross realized gains and (losses) on derivative instruments recognized in margin for the three and nine months ended September 30, 2013 and 2012.

	Statement of Revenues and Expenses Location	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
		(dollars in thousands)			
Designated as hedges:					
Natural Gas Swaps	Fuel	**$ —**	$ 173	**$ —**	$ 197
Natural Gas Swaps	Fuel	**—**	(3,934)	**—**	(9,204)
Not Designated as hedges:					
Natural Gas Swaps	Fuel	**122**	—	**688**	—
Natural Gas Swaps	Fuel	**(3,089)**	—	**(4,002)**	—
		$(2,967)	$(3,761)	**$(3,314)**	$(9,007)

The following table presents the gross unrealized gains and (losses) on derivative instruments deferred on the balance sheet at September 30, 2013 and December 31, 2012.

	Balance Sheet Location	2013	2012
		(dollars in thousands)	
Not designated as hedges:			
Interest rate options	Regulatory asset	**$(41,544)**	$(74,217)
Natural gas swaps	Regulatory asset	**(197)**	(1,085)
		$(41,741)	$(75,302)

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 at September 30, 2013.

	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)			
Assets:				
Natural gas swaps	$ (409)	$212	$ —	$ (197)
Interest rate options	$43,531	$ —	$(31,060)	$12,471

(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 trust fund are directly added to or deducted from the regulatory asset for asset retirement obligations. Realized gains and losses on the nuclear decommissioning trust fund are also recorded to the regulatory asset. All realized and unrealized gains and losses are determined using the specific identification method. Approximately 76% of these gross unrealized losses were in effect for less than one year.

The following tables summarize the activities for available-for-sale securities as of September 30, 2013 and December 31, 2012.

		Gross Unrealized (dollars in thousands)		
September 30, 2013	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$178,794**	**$51,750**	**$ (1,230)**	**$229,314**
Debt	**162,452**	**7,593**	**(8,090)**	**161,955**
Other	**13,008**	**—**	**—**	**13,008**
Total	**$354,254**	**$59,343**	**$ (9,320)**	**$404,277**

		Gross Unrealized (dollars in thousands)		
December 31, 2012	Cost	Gains	Losses	Fair Value
Equity	$153,846	$45,071	$(3,675)	$195,242
Debt	163,127	10,286	(4,501)	168,912
Other	13,654	—	—	13,654
Total	$330,627	$55,357	$(8,176)	$377,808

(E) *Recently Issued or Adopted Accounting Pronouncements.* In July 2013, the Financial Accounting Standards Board (FASB) issued "Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exist." The update provides guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The adoption of this standard is effective for us January 1, 2014 and is not expected to have a material effect on our consolidated financial statements.

In December 2011, FASB issued "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities," which modifies the disclosure requirements for offsetting financial instruments and derivative instruments. The update requires an entity to disclose information about offsetting and related arrangements and the effect of those arrangements on its financial position. The adoption of this standard was effective for us January 1, 2013 and did not have a material impact on our consolidated financial statements.

In February 2013, the FASB issued "Comprehensive Income (Topic 220): Reporting Amounts Reclassified out of Accumulated Other Comprehensive Income," which amended certain provisions of ASC 220 "Comprehensive Income." The update requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective items on the income statement for reclassified amounts that are required by U.S. GAAP to be reclassified entirely to net income. The update also requires additional footnote disclosures for reclassified amounts that are not required by U.S. GAAP to be reclassified entirely to net income. The adoption of this standard did not have a material impact on our consolidated financial statements.

(F) *Accumulated Comprehensive Margin.* 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 Condensed Statements of Patronage Capital and Membership Fees and Accumulated Other Comprehensive Margin. 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 2012 Form 10-K. Amounts reclassified to net margin in the table below are reflected in "Other income" on our unaudited Condensed Statement of Revenues and Expenses.

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

	Accumulated Other Comprehensive Margin Three Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at June 30, 2012	$1,446
Unrealized gain	165
(Gain) reclassified to net margin	(123)
Balance at September 30, 2012	$1,488
Balance at June 30, 2013	$ (399)
Unrealized gain	181
Loss reclassified to net margin	24
Balance at September 30, 2013	**$ (194)**

	Nine Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at December 31, 2011	$ 618
Unrealized gain	1,076
(Gain) reclassified to net margin	(206)
Balance at September 30, 2012	$ 1,488
Balance at December 31, 2012	$ 903
Unrealized (loss)	(1,041)
(Gain) reclassified to net margin	(56)
Balance at September 30, 2013	**$ (194)**

(G) *Contingencies and Regulatory Matters.*

General

We are subject to certain claims and legal actions arising in the ordinary course of our business. The ultimate outcome of any pending or current proceedings against us cannot be predicted at this time; however, except as discussed in "—*Nuclear Construction*" below, management does not anticipate that the liabilities, if any, for any current proceedings against us, if adversely determined, will have a material effect on our financial condition or results of operations.

Nuclear Construction

In April 2008, Georgia Power Company, acting for itself and as agent for Oglethorpe, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia (collectively, the Co-owners), and Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, the Contractor) entered into an engineering, procurement, and construction agreement (Vogtle No. 3 and No. 4 Agreement) to design, engineer, procure, and construct 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 Vogtle No. 3 and No. 4 Agreement, 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.

The most significant litigation relates to costs associated with design changes to the Westinghouse AP1000 Design Control Document (DCD) and costs associated with 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. In July 2012, the Co-owners and Contractor began negotiations regarding these costs, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the contract. The Contractor has claimed that its estimated adjustment attributable to us, based on our ownership interest, is approximately $280,000,000 in 2008 dollars with respect to these issues. The Contractor has also asserted that it is entitled to schedule extensions. 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. 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. On August 30, 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. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit on September 27, 2013. While litigation has commenced 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 September 30, 2013, 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.

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

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, the purchase of emission allowances, or changes or delays in the location, design, construction or operation of new facilities. 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 or 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. For example, during 2013, approximately 150 plaintiffs have filed complaints against us and the other co-owners of Plant Scherer claiming personal injury and property damage arising from the alleged release of hazardous substances from the plant, primarily related to the coal-ash pond, into the surrounding groundwater and air.

(H) *Restricted Cash.* At September 30, 2013 and December 31, 2012, we had restricted cash totaling $31,221,000 and $9,109,000, respectively, of which $31,064,000 and $8,953,000, respectively, was classified as long-term. The long-term restricted cash balance at September 30, 2013 and December 31, 2012 consisted primarily of funds posted as collateral by counterparties to our interest rate options.

(I) *Restricted Short-term Investments.* At September 30, 2013 and December 31, 2012, we had $254,854,000 and $64,671,000, respectively, on deposit with the Rural Utilities Service in the Cushion of Credit Account. The restricted funds will be utilized for future Rural Utilities Service Federal Financing Bank debt service payments. The deposit earns interest at a Rural Utilities Service guaranteed rate of 5% per annum.

(J) *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 accompanying condensed balance sheet as of September 30, 2013 and December 31, 2012.

	2013	2012
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt[a]	**$ 77,911**	$ 86,319
Amortization on capital leases[b]	**19,154**	28,670
Outage costs[c]	**35,329**	30,901
Interest rate swap termination fees[d]	**14,333**	17,326
Asset retirement obligations[e]	**—**	11,382
Depreciation expense[f]	**48,718**	49,785
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs[g]	**26,627**	23,030
Interest rate options cost[h]	**58,691**	75,716
Deferral of effects on net margin—Smith Energy Facility[i]	**52,384**	21,394
Other regulatory assets[j]	**6,127**	8,379
Total Regulatory Assets	**$339,274**	$352,902
Regulatory Liabilities:		
Accumulated retirement costs for other obligations[e]	**$ 25,106**	$ 28,846
Deferral of effects on net margin—Hawk Road Energy Facility[i]	**22,302**	17,113
Major maintenance reserve[k]	**28,012**	30,948
Deferred debt service adder[l]	**54,785**	47,486
Other regulatory liabilities[j]	**8,982**	5,592
Total Regulatory Liabilities	**$139,187**	$129,985
Net Regulatory Assets	**$200,087**	$222,917

(a) Represents premiums paid, together with unamortized transaction costs related to reacquired debt amortized over the period 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. Recovered over the remaining terms of the leases through 2031.

(c) Consists of both coal-fired and nuclear refueling outage costs. Coal-fired outages are amortized on a straight-line basis to expense over an 18 to 36-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) Represents difference in timing of recognition of the costs of decommissioning for financial statement purposes and for ratemaking purposes.

(f) 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.

(g) 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.

(h) Deferral of net loss associated with the change in fair value of the interest rate options to hedge interest rates on a portion of expected borrowings related to Vogtle Units No. 3 and No. 4 construction. Amortization will commence effective with the expected principal repayment of the Department of Energy (DOE)-guaranteed loan and amortized over the expected remaining life of the DOE-guaranteed loan which will finance a portion of the construction project.

(i) 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.

(j) The amortization period for other regulatory assets range up to 36 years and the amortization period of other regulatory liabilities range up to 13 years.

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

(l) Collections to fund debt payments in excess of depreciation expense through the end of 2025; deferred revenues will be amortized over the remaining useful life of the plants.

(K) *Member Power Bill Prepayments.* We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. At September 30, 2013, member power bill prepayments as reflected on the unaudited condensed balance sheets are $108,023,000, of which $75,410,000 is classified as current liabilities and $32,613,000 as deferred credits and other liabilities. The prepayments are being credited against members' power bills through January 2018, with the majority of the balance scheduled to be credited by the end of 2013.

(L) *Debt.* On March 1, 2013, instead of remarketing the $212,760,000 of pollution control revenue bonds that were originally issued on our behalf by the Development Authorities of Appling, Burke and Monroe Counties, and were subject to mandatory tender, we elected to redeem the bonds with commercial paper. On April 23, 2013, the Development Authority of Appling County (Georgia), the Development Authority of Burke County (Georgia) and the Development Authority of Monroe County (Georgia) issued, on our behalf, $212,760,000 in aggregate principal amount of tax-exempt pollution control revenue bonds for the purpose of refinancing costs associated with certain of our air or water pollution control and sewage or solid waste disposal facilities. The proceeds were used to repay the outstanding commercial paper utilized to redeem the pollution control revenue bonds that were redeemed on March 1, 2013. Each series of bonds bear interest at 2.40% per annum until April 1, 2020, the initial mandatory tender date. The pollution control revenue bonds are scheduled to mature starting in 2038 through 2040. Our payment obligations related to these bonds are secured under our first mortgage indenture.

For the nine month period ended September 30, 2013, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $662,880,000 for long-term financing of the Smith Energy Facility and general and environmental improvements at existing plants.

On October 31, 2013, we received $13,217,000 in advances from RUS for general and environmental improvements at existing plants.

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 through a combination of our generation assets and, to a lesser extent, power purchased from power marketers and other suppliers. As with cooperatives generally, we operate on a not-for-profit basis.

Results of Operations

For the Three and Nine Months Ended September 30, 2013 and 2012

Net Margin

Throughout the year, we monitor our operating results and, with board approval, make budget adjustments when and as necessary to ensure our targeted margins for interest ratio is achieved. Under our first mortgage indenture, we are required to establish and collect rates that are reasonably expected, together with our other revenues, to yield at least a 1.10 margins for interest ratio in each fiscal year. However, to enhance margin coverage during a period of increased capital requirements, our board of directors approved budgets for 2012, 2013 and 2014 to achieve a 1.14 margins for interest ratio. As our capital requirements continue to evolve, our board of directors will continue to evaluate the level of margin coverage and may choose to change the targeted margins for interest ratio in the future, although not below 1.10.

Our net margin for the three-month and nine-month periods ended September 30, 2013 was $20.1 million and $66.6 million compared to $23.7 million and $48.1 million for the same periods of 2012. Through September 30, 2013, we collected approximately 160% of our targeted net margin of $41.5 million for the year ending December 31, 2013. Actual net margins exceeding targeted margins during the fiscal year is typical as our capacity revenues are recorded evenly throughout the year and our management generally budgets conservatively. We anticipate our board 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.

Operating Revenues

Our operating revenues fluctuate from period to period based on several factors, including 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. Total revenues from sales to members decreased 6.8% and 3.8% in the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012. Megawatt-hour sales to members decreased 15.4% and 14.2% for the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012. The average total revenue per megawatt-hour from sales to members increased 10.1% and 12.1% for the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012.

The components of member revenues for the three-month and nine-month periods ended September 30, 2013 and 2012 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	**2013**	2012
Capacity revenues	**$ 182,107**	$ 171,267	**$ 547,482**	$ 518,900
Energy revenues	**133,539**	167,501	**361,008**	425,581
Total	**$ 315,646**	$ 338,768	**$ 908,490**	$ 944,481
Kilowatt-hours sold to members	**5,210,893**	6,156,398	**14,097,380**	16,422,271
Cents per kilowatt-hour	**6.06¢**	5.50¢	**6.44¢**	5.75¢

Capacity revenues from members increased 6.3% and 5.5% for the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012. Capacity revenues relate primarily to the assignment to each of our members the fixed costs associated with our business, including fixed production expenses, depreciation and amortization expenses and interest charges. Each member is required to pay us for capacity furnished under its wholesale power contract in accordance with rates we establish. Our capacity revenues are based on the costs we expect to incur on an annual basis and are subject to adjustment by our board such that our net margins will achieve, but not exceed, the targeted margins for interest ratio. See "—*Net Margin*" for discussion regarding margins for interest ratio.

Energy revenues were 20.3% and 15.2% lower for the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012. Our average energy revenue per megawatt-hour from sales to members decreased 5.8% and 1.2% for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012. The decrease in energy revenues for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012 resulted primarily from lower coal-fired and natural gas generation. For a discussion of total fuel costs and total generation, see "—*Operating Expenses.*"

Sales to Non-Members. Sales to non-members for the three-month and nine-month periods ended September 30, 2013 were 11.8% and 28.4% lower as compared to the same periods of 2012. Sales to non-members in 2012 consisted of capacity and energy sales made under an agreement to sell the entire output of Unit No. 1 of the Thomas A. Smith Energy Facility to Georgia Power Company through May 31, 2012, as well as energy sales to other non-members from Smith Units No. 1 and No. 2. The decrease for the nine-month period ended September 30, 2013 as compared to the same period of 2012 was primarily due to the expiration of this agreement with Georgia Power. This decrease was partially offset by increased energy sales to other non-members.

Operating Expenses

Operating expenses for the three-month and nine-month periods ended September 30, 2013 decreased 11.7% and 9.9% as compared to the same periods of 2012. The decrease for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012 was primarily due to lower fuel costs. For the nine-month period ended September 30, 2013 as compared to the same period of 2012, lower depreciation and amortization expenses, which were partially offset by higher purchased power costs and accretion expense, also contributed to the decrease in operating expenses.

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

Fuel Source	Three Months Ended September 30, 2013 Cost (thousands)	2013 Generation (MWh)	2013 Cost per MWh	2012 Cost (thousands)	2012 Generation (MWh)	2012 Cost per MWh
Coal	**$ 53,934**	**1,818,076**	**$29.67**	$ 69,000	2,292,572	$30.10
Nuclear	**23,238**	**2,636,084**	**8.82**	22,092	2,556,238	8.64
Gas:						
Combined Cycle	**55,665**	**1,700,112**	**32.74**	59,537	2,298,222	25.91
Combustion Turbine	**5,415**	**72,358**	**74.84**	20,549	456,603	45.00
	$138,252	**6,226,630**	**$22.20**	$171,178	7,603,635	$22.51

Fuel Source	Nine Months Ended September 30, 2013 Cost (thousands)	2013 Generation (Mwh)	2013 Cost per MWh	2012 Cost (thousands)	2012 Generation (Mwh)	2012 Cost per MWh
Coal	**$139,746**	**4,792,309**	**$29.16**	$187,905	6,041,167	$31.10
Nuclear	**64,168**	**7,295,446**	**8.80**	60,125	7,602,777	7.91
Gas:						
Combined Cycle	**137,335**	**4,119,313**	**33.34**	139,707	5,679,273	24.60
Combustion Turbine	**10,218**	**136,690**	**74.75**	31,857	739,092	43.10
	$351,467	**16,343,758**	**$21.50**	$419,594	20,062,309	$20.91

For the three-month and nine-month periods ended September 30, 2013, total fuel costs decreased 19.2% and 16.2% and megawatt-hour generation decreased 18.1% and 18.5%, respectively, compared to the same periods of 2012. Milder temperatures in 2013 as compared to 2012 contributed to the decrease in megawatt-hour generation. Average fuel costs per megawatt-hour decreased 1.4% and increased 2.8% in the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012. The decrease in total fuel costs was primarily due to lower generation at Plant Wansley and our natural gas-fired facilities. Plant Wansley, which is fueled by higher cost eastern coal, was in reserve shutdown for most of the nine-month period ended September 30, 2013 primarily due to more economical generation from natural gas-fired facilities. Generation from our gas-fired facilities also decreased in the three-month and nine-month periods ended September 30, 2013 versus the same periods of 2012 primarily due to lower utilization of the Smith Energy Facility, although all of our gas-fired facilities experienced decreased generation in the three-month and nine-month periods of 2013 compared to the same periods of 2012. The decrease in total fuel costs was partially offset by increased natural gas prices in 2013. As was the case in 2012, generation from Smith continues to be sold to non-members.

Depreciation and amortization costs increased 7.9% and decreased 5.2% for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012. The increase in depreciation expense in the third quarter of 2013 as compared to the same quarter of 2012 was primarily due to $249.7 million of environmental capital improvements at Plant Scherer that were placed into service in May and August of 2013. The decrease for the nine-month period ended September 30, 2013 as compared to the same period of 2012 was primarily due to the May 2012 completion of amortization of the intangible asset associated with a purchase and sale agreement with Georgia Power which was acquired as part of the Smith acquisition. In addition, amortization expense of leasehold improvements for Scherer Unit No. 2 capital leases decreased because we extended the lease terms in June 2012.

Purchased power costs increased 14.0% and 14.3% for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012. The increase in purchased power costs resulted primarily from an increase in kilowatt-hours acquired under our energy replacement program, which replaces power from our owned generation facilities with power purchased on the spot market at a lower price. In addition, increased transmission expenses contributed to the higher purchased power costs.

Accretion expense increased 17.8% and 16.9% for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012. The increase in accretion expense resulted primarily from an increase in the asset retirement obligation for the decommissioning of our ash ponds based on December 2012 studies.

The effect on net margin of the Smith and Hawk Road Energy Facilities is being deferred until 2016, at which time the amounts will be amortized over the remaining life of the plants. In implementing the deferral plans, we assumed that our members would generally not require energy from the plants until 2016. The change in the deferral resulted partly from the expiration of the power purchase and sale agreement with Georgia Power that ended in May 2012, partly from an increase in interest expense for the long-term financing of Smith, which was obtained in July 2013, and partly from reduced margins associated with non-member energy sales from Smith.

Other Income

Investment income increased 29.8% and 5.9% for the three-month and nine-month periods ended September 30, 2013 as compared to the same periods of 2012. An increase in funds deposited in the Rural Utilities Service Cushion of Credit Account as well as increased investment income from nuclear decommissioning trust funds contributed to higher investment income in the three-month and nine-month periods of 2013 as compared to same periods of 2012. Partially offsetting the increase during the nine-month period ended September 30, 2013, was a reduction in investment income associated with the Rocky Mountain lease transactions. During the second half of 2012, five of the six lease transactions were terminated.

The gain on termination of Rocky Mountain transactions for the three-month and nine-month periods ended September 30, 2012 represented the net gain resulting from the July 2012 termination of three of the six leases.

Interest charges

Allowance for debt funds used during construction increased 11.6% and 18.5% in the three-month and nine-month periods ended September 30, 2013 compared to the same periods of 2012 primarily due to construction expenditures for Vogtle Units No. 3 and No. 4.

Financial Condition

Balance Sheet Analysis as of September 30, 2013

Assets

Cash used for property additions for the nine-month period ended September 30, 2013 totaled $414 million. Of this amount, approximately $251 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4, approximately $67 million for environmental control systems being installed primarily at Plant Scherer and approximately $39 million for nuclear fuel purchases. The remaining expenditures were for normal additions and replacements to existing generation facilities.

The $254.9 million of restricted short-term investments at September 30, 2013 represent funds deposited into a Rural Utilities Service Cushion of Credit Account with the U.S. Treasury and earns interest at a guaranteed rate of 5% per annum. 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.

Equity and Liabilities

Long-term debt and capital leases due within one year increased $279.0 million during the nine-month period ended September 30, 2013 primarily due to the reclassification of a $260.0 million term loan due in April 2014.

Accounts payable decreased $62.7 million for the nine-month period ended September 30, 2013. The December 31, 2012 payable balance included $25.2 million in credits due to the members for a board approved reduction to 2012 revenue requirements as a result of margins collected in excess of our 2012 target. These credits were applied to the members' bills in the first quarter of 2013. The decrease was also the result of a $24.6 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 construction. In addition, there was a $15.6 million decrease in accounts payable primarily related to property tax payments.

Member power bill prepayments represent funds received from the members for the prepayment of their monthly power bills. At September 30, 2013, $75.4 million of member power bill prepayments was classified as a current liability and $32.6 million was classified as a long-term liability. During the nine-month period ended September 30, 2013, $102.1 million of prepayments were received from the members and $100.0 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note K of Notes to Unaudited Condensed Financial Statements and "—Capital Requirements and Liquidity and Sources of Capital—*Liquidity.*"

Capital Requirements and Liquidity and Sources of Capital

Vogtle Units No. 3 and No. 4.

We, along with Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton are participating in the construction of two Westinghouse AP1000 nuclear generating units at Plant Vogtle, each with a nominally rated generating capacity of approximately 1,100 megawatts. Our ownership interest is 30%, representing 660 megawatts of total capacity. As of September 30, 2013, our total capitalized costs to date for Vogtle Units No. 3 and No. 4 were $1.9 billion.

As previously disclosed, separate groups of petitioners had filed petitions in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the Nuclear Regulatory Commission's certification of the design control document and the issuance of the combined construction permits and operating licenses. On May 14, 2013, the Court ruled in favor of the Nuclear Regulatory Commission and upheld the certification of the design control document and the issuance of the combined construction permits and operating licenses. On July 23, 2013, the Court rejected the petitioner's request for rehearing. The deadline for any further appeals expired without the petitioners seeking review.

For additional information about the Vogtle construction project, see "Item 1—BUSINESS—OUR POWER SUPPLY RESOURCES—Future Power Resources—*Plant Vogtle Units No. 3 and No. 4*" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2012 Form 10-K. Also see "Note G—*Contingencies and Regulatory Matters—Nuclear Construction*" of Notes to Unaudited Condensed Financial Statements herein.

Environmental Regulations

The Environmental Protection Agency, or EPA, continues to develop a number of rules that significantly expand the scope of regulation of air emissions, water intake and waste management at power plants.

On September 20, 2013, EPA signed rules reproposing (and rescinding) the April 2012 New Source Performance Standards (NSPS) for certain new fossil fuel-fired electric generating units. In this new action, EPA proposed standards of performance for fossil fuel-fired electric utility steam generating units that burn coal and other fossil fuels based on partial implementation of carbon capture and storage (CCS). It also proposed separate standards for natural gas-fired stationary combustion turbines that do not involve CCS. Simple cycle "peaking" turbines, certain biomass and oil-fired units and modified, reconstructed and existing sources were exempted or not addressed by the proposal. Once EPA promulgates a NSPS for a category of new, modified or reconstructed emissions sources, it is required to establish guidelines requiring states to develop emission standards for the same category of existing sources. Thus, greenhouse gas NSPS for existing sources may be issued at some point in the future. These proposed rules will likely be challenged when finalized. We cannot predict at this time how further developments may affect the regulation of greenhouse gas emissions from our power plants, including capital requirements.

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 2012 Form 10-K.

Liquidity

At September 30, 2013, we had $1.5 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $437 million in cash and cash equivalents and $1.1 billion of unused and available committed credit arrangements.

At September 30, 2013, we had in excess of $1.9 billion of committed credit arrangements in place, comprised of the five separate facilities reflected in the table below.

Committed Credit Facilities

	Authorized Amount	Available 9/30/2013	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit led by Bank of America	$1,265	$ 526[1]	June 2015
Syndicated Line of Credit led by CoBank	150	150	September 2014
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	34[2]	December 2013
Secured facilities:			
CFC Line of Credit[3]	250	250	December 2013
Total	**$1,925**	**$1,070**	

(1) Of the portion of this facility that is unavailable, $603.8 million is dedicated to support commercial paper we have issued and $135.5 million relates to letters of credit issued under this facility to support variable rate demand bonds.

(2) Of the portion of this facility that is unavailable, $113.7 million relates to letters of credit issued under this facility to support variable rate demand bonds and $2.2 million relates to letters of credit issued to post collateral to third parties.

(3) This facility has a term loan option that can extend the maturity to December 31, 2043.

As of September 30, 2013, we were using our commercial paper program to provide interim funding for (i) payments related to the construction of Vogtle Units No. 3 and No. 4, and (ii) the upfront payments made in connection with our interest rate hedging program.

Under our commercial paper program, we are authorized to issue commercial paper in amounts that do not exceed the amount of any committed backup lines of credit, thereby providing 100% dedicated support for any commercial paper outstanding.

Under our unsecured committed lines of credit, we have the ability to issue letters of credit totaling $835 million in the aggregate, of which $584 million remained available at September 30, 2013. 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.

We are currently negotiating a new 3-year, $150 million unsecured credit facility with JPMorgan Chase Bank, N.A. to replace an existing credit facility we have with them and expect to close on the new facility in November 2013. We are also negotiating a restructuring of our existing $250 million secured credit facility with CFC into a new 5-year, $250 million unsecured credit facility and expect to close on this new facility in December 2013.

Between our credit arrangements and projected cash on hand, we believe we have sufficient liquidity to cover our normal operations and to provide interim financing for construction of Vogtle Units No. 3 and No. 4.

Several of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At September 30, 2013, the required minimum level was $575 million and our actual patronage capital was $740 million. Additional covenants contained in several of our credit facilities limit the amount of secured indebtedness and unsecured indebtedness we can have outstanding. At September 30, 2013, the most restrictive of these covenants limits our secured indebtedness to $9.5 billion and our unsecured indebtedness to $4.0 billion. At September 30, 2013, we had $6.4 billion of secured indebtedness and $972 million of unsecured indebtedness outstanding, which was well within the covenant thresholds.

At September 30, 2013, current assets included $255 million of restricted short-term investments pursuant to deposits made into a Rural Utilities Service Cushion of Credit Account. See "—Balance Sheet Analysis as of September 30, 2013—*Assets*" for more information regarding this account.

Financing Activities

First Mortgage Indenture. At September 30, 2013, we had $6.2 billion of long-term debt outstanding under our first mortgage indenture secured equally and ratably by a lien on substantially all of our tangible and some of our intangible assets, including those we acquire in the future. See "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities—First Mortgage Indenture*" in our 2012 Form 10-K for further discussion of our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. In July 2013, we received a $492.6 million advance for the full amount of the loan covering the majority of the acquisition cost of Smith, a portion of which was utilized to repay $232.6 million of outstanding commercial paper prior to the end of the third quarter. We currently have four other approved Rural Utilities Service-guaranteed loans, totaling $871 million, which are being funded through the Federal Financing Bank with $469 million remaining to be advanced. When advanced, the debt will be secured under our first mortgage indenture.

Department of Energy-Guaranteed Loan. In May 2010, we signed a conditional term sheet with the Department of Energy that sets forth the general terms of a loan and related loan guarantee that would fund up to $3.057 billion of the cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4. We continue to work with the Department of Energy on this proposed financing; however, final approval and issuance of a loan guarantee is subject to negotiation of definitive agreements, completion of due diligence and satisfaction of other conditions. Therefore, there can be no assurance that the Department of Energy will ultimately issue the loan guarantee to us. We expect that we will fund any remaining Vogtle costs not funded under the Department of Energy loan guarantee program through capital market financings. The conditional commitment has been extended by the Department of Energy to December 31, 2013.

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 2012 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 Condensed Financial Statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Not Applicable.

Item 4. Controls and Procedures

As of September 30, 2013, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

There have been no changes in internal control over financial reporting or other factors that occurred during the quarter ended September 30, 2013 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 2012 Form 10-K.

Item 1A. Risk Factors

There have not been any material changes in our risk factors from those reported in "Item 1A—RISK FACTORS" of our 2012 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

On November 6, 2013, Michael L. Smith began serving as our new President and Chief Executive Officer. Prior to joining Oglethorpe, Mr. Smith served as the President and Chief Executive Officer of Georgia Transmission Corporation since 2005 and has over thirty years of experience in the energy industry in the areas of finance, planning, risk control and operations. For additional information regarding Mr. Smith, see our Current Report on Form 8-K, dated as of October 15, 2013.

Item 6. Exhibits

Number	Description
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Michael L. Smith (Principal Executive Officer).
31.2	Rule 13a-14(a)/15d-14(a) Certification, by Elizabeth B. Higgins (Principal Financial Officer).
32.1	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Michael L. Smith (Principal Executive Officer).
32.2	Certification Pursuant to 18 U.S.C. 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Elizabeth B. Higgins (Principal Financial Officer).
101	XBRL Interactive Data File.

SIGNATURES

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

		Oglethorpe Power Corporation (An Electric Membership Corporation)
Date: November 13, 2013	By:	/s/ Michael L. Smith
		Michael L. Smith President and Chief Executive Officer
Date: November 13, 2013		/s/ Elizabeth B. Higgins
		Elizabeth B. Higgins Executive Vice President and Chief Financial Officer (Principal Financial Officer)