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, 2012

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

OglethorpePowerCorporation

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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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FOR THE QUARTER ENDED JUNE 30, 2012

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation
Condensed Balance Sheets
June 30, 2012 and December 31, 2011

	(dollars in thousands)	
	2012 (Unaudited)	2011
Assets		
Electric plant:		
In service	**$ 7,413,780**	$ 7,335,866
Less: Accumulated provision for depreciation	**(3,400,211)**	(3,328,585)
	4,013,569	4,007,281
Nuclear fuel, at amortized cost	**295,764**	284,205
Construction work in progress	**1,990,396**	1,784,264
	6,299,729	6,075,750
Investments and funds:		
Nuclear decommissioning trust fund	**283,676**	268,597
Deposit on Rocky Mountain transactions	**136,501**	132,048
Investment in associated companies	**57,640**	57,626
Long-term investments	**75,357**	80,055
Restricted cash	**20,692**	43,070
Other, at cost	**1,040**	3,564
	574,906	584,960
Current assets:		
Cash and cash equivalents	**409,321**	443,671
Restricted cash	**613**	613
Restricted short-term investments	**63,075**	106,676
Receivables	**157,373**	124,650
Inventories, at average cost	**239,204**	246,795
Prepayments and other current assets	**18,388**	15,562
	887,974	937,967
Deferred charges:		
Deferred debt expense, being amortized	**64,992**	67,470
Regulatory assets	**363,502**	351,547
Other	**35,892**	61,135
	464,386	480,152
	$ 8,226,995	$ 8,078,829

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

Oglethorpe Power Corporation
Condensed Balance Sheets
June 30, 2012 and December 31, 2011

	(dollars in thousands)	
	2012 (Unaudited)	2011
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 658,087**	$ 633,689
Accumulated other comprehensive margin	**1,446**	618
	659,533	634,307
Long-term debt	**5,589,065**	5,562,925
Obligation under capital leases	**142,682**	146,781
Obligation under Rocky Mountain transactions	**136,501**	132,048
	6,527,781	6,476,061
Current liabilities:		
Long-term debt and capital leases due within one year	**165,909**	172,818
Short-term borrowings	**648,122**	461,093
Accounts payable	**72,318**	134,095
Accrued interest	**83,507**	91,106
Accrued taxes	**16,729**	21,118
Member power bill prepayments, current	**56,763**	66,819
Other current liabilities	**19,024**	25,080
	1,062,372	972,129
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**24,876**	26,113
Asset retirement obligations	**309,640**	298,758
Member power bill prepayments, non-current	**37,225**	35,500
Power sale agreement, being amortized	**47,585**	54,816
Regulatory liabilities	**162,478**	164,000
Other	**55,038**	51,452
	636,842	630,639
	$8,226,995	$8,078,829

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 Six Months Ended June 30, 2012 and 2011

	(dollars in thousands)			
	Three Months		Six Months	
	2012	2011	**2012**	2011
Operating revenues:				
Sales to Members	**$310,483**	$327,776	**$605,713**	$597,224
Sales to non-Members	**37,220**	52,027	**61,214**	52,353
Total operating revenues	**347,703**	379,803	**666,927**	649,577
Operating expenses:				
Fuel	**136,349**	161,355	**243,169**	233,804
Production	**89,844**	89,866	**188,343**	179,055
Depreciation and amortization	**40,556**	50,927	**85,100**	85,332
Purchased power	**14,660**	13,600	**29,183**	25,155
Accretion	**4,859**	4,565	**9,716**	9,125
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(2,484)**	(2,753)	**(14,559)**	(11,072)
Total operating expenses	**283,784**	317,560	**540,952**	521,399
Operating margin	**63,919**	62,243	**125,975**	128,178
Other income:				
Investment income	**7,760**	6,926	**16,015**	14,320
Other	**3,156**	3,416	**6,899**	6,782
Total other income	**10,916**	10,342	**22,914**	21,102
Interest charges:				
Interest expense	**78,839**	72,279	**154,846**	142,945
Allowance for debt funds used during construction	**(20,017)**	(17,753)	**(40,437)**	(32,981)
Amortization of debt discount and expense	**5,135**	5,341	**10,082**	10,488
Net interest charges	**63,957**	59,867	**124,491**	120,452
Net margin	**$ 10,878**	$ 12,718	**$ 24,398**	$ 28,828

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 Six Months Ended June 30, 2012 and 2011

	(dollars in thousands)			
	Three Months		Six Months	
	2012	2011	**2012**	2011
Net margin	**$10,878**	$12,718	**$24,398**	$28,828
Other comprehensive margin:				
Unrealized gain on available-for-sale securities	**120**	613	**828**	592
Total comprehensive margin	**$10,998**	$13,331	**$25,226**	$29,420

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 Six Months Ended June 30, 2012 and 2011

(dollars in thousands)

	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Margin (Deficit)	Total
Balance at December 31, 2010	$595,952	$ (469)	$595,483
Components of comprehensive margin:			
Net margin	28,828	—	28,828
Unrealized gain on available-for-sale securities	—	592	592
Balance at June 30, 2011	$624,780	$ 123	$624,903
Balance at December 31, 2011	$633,689	$ 618	$634,307
Components of comprehensive margin:			
Net margin	24,398	—	24,398
Unrealized gain on available-for-sale securities	—	828	828
Balance at June 30, 2012	**$658,087**	**$1,446**	**$659,533**

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

Oglethorpe Power Corporation
Condensed Statements of Cash Flows (Unaudited)
For the Six Months Ended June 30, 2012 and 2011

	(dollars in thousands)	
	2012	2011
Cash flows from operating activities:		
Net margin	**$ 24,398**	$ 28,828
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**156,664**	145,590
Accretion cost	**9,716**	9,125
Amortization of deferred gains	**(2,830)**	(2,830)
Allowance for equity funds used during construction	**(1,432)**	(1,404)
Deferred outage costs	**(13,379)**	(36,672)
Deferral of Hawk Road and Smith Energy Facilities effect on net margin	**(14,559)**	(11,072)
Gain on sale of investments	**(5,625)**	(10,324)
Regulatory deferral of costs associated with nuclear decommissioning	**165**	5,553
Other	**(3,908)**	(3,622)
Change in operating assets and liabilities:		
Receivables	**(34,699)**	(54,078)
Inventories	**7,591**	1,171
Prepayments and other current assets	**(2,826)**	(1,674)
Accounts payable	**(43,758)**	19,553
Accrued interest	**(7,599)**	(22,796)
Accrued taxes	**(4,389)**	(7,920)
Other current liabilities	**(3,644)**	1,376
Member power bill prepayments	**(8,331)**	(41,957)
Total adjustments	**27,157**	(11,981)
Net cash provided by operating activities	**51,555**	16,847
Cash flows from investing activities:		
Property additions	**(346,654)**	(397,229)
Plant acquisition	**—**	(529,310)
Activity in decommissioning fund—Purchases	**(418,240)**	(557,748)
—Proceeds	**415,247**	554,710
Decrease in restricted cash and cash equivalents	**22,378**	2,530
Decrease in restricted short-term investments	**43,601**	81,660
Increase in investment in associated organizations	**(33)**	(603)
Activity in other long-term investments—Purchases	**(2,993)**	(824)
—Proceeds	**10,846**	700
Activity on interest rate options—Purchases/Collateral returned	**(43,070)**	—
—Collateral received	**20,690**	—
Other	**11,740**	(3,955)
Net cash used in investing activities	**(286,488)**	(850,069)
Cash flows from financing activities:		
Long-term debt proceeds	**79,194**	793,999
Long-term debt payments	**(68,678)**	(260,981)
Increase in short-term borrowings, net	**187,029**	47,694
Other	**3,038**	(1,756)
Net cash provided by financing activities	**200,583**	578,956
Net decrease in cash and cash equivalents	**(34,350)**	(254,266)
Cash and cash equivalents at beginning of period	**443,671**	672,212
Cash and cash equivalents at end of period	**$ 409,321**	$ 417,946
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 115,719**	$ 126,758
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	**$ (14,733)**	$ 30,335

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 Six Months ended June 30, 2012 and 2011

(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 six-month periods ended June 30, 2012 and 2011. 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, 2011, as filed with the SEC. The results of operations for the three- and six-month periods ended June 30, 2012 are not necessarily indicative of results to be expected for the full year. As noted in our 2011 Form 10-K, our revenues consist primarily of sales to our 39 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 2011 Form 10-K.)

(B) *Fair Value Measurement.* 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 as of June 30, 2012 and December 31, 2011.

		Fair Value Measurements at Reporting Date Using		
	June 30, 2012	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
		(dollars in thousands)		
Decommissioning funds:				
Domestic equity	**$111,031**	$111,031	$ —	$ —
International equity	**41,948**	41,948	—	—
Corporate bonds	**48,046**	—	48,046	—
US Treasury and government agency securities	**55,231**	55,231	—	—
Agency mortgage and asset backed securities	**15,497**	—	15,497	—
Other	**11,923**	11,923	—	—
Bond, reserve and construction funds	**197**	197	—	—
Long-term investments:				
Corporate bonds	**5,995**	—	5,995	—
US Treasury and government agency securities	**6,889**	6,889	—	—
Agency mortgage and asset backed securities	**2,670**	—	2,670	—
Mutual funds	**59,803**	59,803	—	—
Interest rate options	**39,215**	—	—	39,215[(1)]
Natural gas swaps	**(4,265)**	—	(4,265)	—

	December 31, 2011	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)			
Decommissioning funds:				
Domestic equity	$102,285	$102,285	$ —	$ —
International equity	39,618	39,618	—	—
Corporate bonds	41,338	—	41,338	—
US Treasury and government agency securities	41,697	41,697	—	—
Agency mortgage and asset backed securities	28,519	—	28,519	—
Derivative instruments	(982)	—	—	(982)
Other	16,122	16,122	—	—
Bond, reserve and construction funds	2,720	2,720	—	—
Long-term investments	80,055	72,342	—	7,713[2]
Interest rate options	69,446	—	—	69,446[1]
Natural gas swaps	(7,220)	—	(7,220)	—

(1) Interest rate options as reflected on the unaudited condensed Balance Sheet includes the fair value of the interest rate options offset by $20,690,000 and $43,070,000 of collateral received by the counterparties at June 30, 2012 and December 31, 2011, respectively.

(2) Represents auction rate securities investments we held.

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 six months ended June 30, 2012 and 2011.

	Three Months Ended June 30, 2012
	Interest rate options
	(dollars in thousands)
Assets (Liabilities):	
Balance at March 31, 2012	$ 66,860
Total gains or losses (realized/unrealized):	
Included in earnings (or changes in net assets)	(27,645)
Balance at June 30, 2012	**$ 39,215**

	Three Months Ended June 30, 2011	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at March 31, 2011	$(548)	$8,408
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	43	40
Liquidations	—	(400)
Balance at June 30, 2011	$(505)	$8,048

	Six Months Ended June 30, 2012		
	Decommissioning funds	Long-term investments	Interest rate options
	(dollars in thousands)		
Assets (Liabilities):			
Balance at December 31, 2011	$(982)	$ 7,713	$69,446
Total gains or losses (realized/unrealized):			
Included in earnings (or changes in net assets)	982	—	(30,231)
Impairment included in other comprehensive margin (deficit)	—	887	—
Liquidations	—	(8,600)	—
Balance at June 30, 2012	**$ —**	**$ —**	**$39,215**

	Six Months Ended June 30, 2011	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at December 31, 2010	$(452)	$8,671
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(53)	77
Liquidations	—	(700)
Balance at June 30, 2011	$(505)	$8,048

On February 15, 2012, we sold our remaining $8,600,000 of auction rate securities, which resulted in a loss of $1,075,000. The loss was recorded as a regulatory asset and is being charged to income over a period of four years.

(C) *Disclosures about Derivative Instruments and Hedging Activities.* Our risk management and compliance committees provide general oversight over all risk management activities, including but not limited to, commodity trading, investment portfolio management and interest rate risk management. We use commodity trading derivatives, which are generally designated as hedging instruments under authoritative guidance for accounting for derivatives and hedging, to manage our exposure to fluctuations in the market price of natural gas. Consistent with our rate-making, unrealized gains or losses on natural gas swaps designated as hedging instruments are reflected as an unbilled receivable or as a regulatory asset. 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 gains or losses from the interest rate options are recorded to the related 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. We do not hold or enter into derivative transactions for trading or speculative purposes. Consistent with our rate-making, unrealized gains or losses from the decommissioning trust fund are recorded as an increase or decrease to the regulatory asset or liability.

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 natural gas counterparties, and 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, 2012, 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 June 30, 2012 and December 31, 2011 the estimated fair value of our natural gas contracts was an unrealized loss of approximately $4,265,000 and $7,220,000, respectively.

As of June 30, 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 were triggered on June 30, 2012 due to our credit rating being downgraded below investment grade, we would have been required to post letters of credit totaling up to $5,288,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of June 30, 2012 that is expected to settle or mature each year:

Year	**Natural Gas Swaps (MMBTUs)** (in millions)
2012	9.5
2013	1.7
2014	0.7
Total	**11.9**

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. We have entered into a conditional term sheet with the Department of Energy to finance up to $3.057 billion of the cost to construct Vogtle Units No. 3 and No. 4. The term sheet provides for quarterly draws from 2012 through 2017 and interest rates that will be based on U.S. Treasury rates at the time of each draw, plus a fixed spread. In fourth quarter of 2011, we purchased interest rate options at a cost of $100,000,000 to hedge the interest rates on approximately $2.2 billion of the expected Department of Energy-guaranteed loan, representing a substantial portion of the projected borrowings from 2013 through 2017.

The interest rate options, commonly known as LIBOR swaptions, give us the right, but not the obligation, to enter into a swap in which we would pay a fixed rate and receive a floating LIBOR rate. However, the swaptions are required to be cash settled based on their value on the expiration date, thereby effectively capping our interest rates by offsetting the present value cost of an increase in interest rates above the fixed rate. The cash settlement value depends on the extent to which prevailing LIBOR swap rates exceed the fixed rate on the underlying swap, and the value would be zero if swap rates are at or below the fixed rate upon expiration. The fixed rates on the LIBOR swaptions we purchased are in the range of 150 to 250 basis points above current LIBOR swap rates and the weighted average fixed rate is 4.17%. The swaptions' expiration dates, which range from 2013 through 2017, are timed to match the expected quarterly draw dates of the Department of Energy-guaranteed loan advances to be hedged. As the interest rate options' value is independent from the Department of Energy-guaranteed loan, the interest rate options could also serve as a hedge of interest rates on an alternative source of financing.

We paid the entire premiums at the time we entered into these interest rate option transactions and have no additional payment obligations. However, upon expiration of the interest rate options, each counterparty will be obligated to pay us the cash value of the interest rate options, if any. These derivatives are recorded at fair value and hedge accounting is not applied. At June 30, 2012 and December 31, 2011, the fair value of these interest rate options was approximately $39,215,000 and $69,446,000, respectively. To manage our credit exposure to these 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 interest rate options outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from $0 to $10,000,000 depending on each counterparty's credit rating. As of June 30, 2012 and December 31, 2011, we held $20,690,000 and $43,070,000 of funds posted as collateral by the counterparties, respectively. The collateral received is recorded as long-term restricted cash on our balance sheet. The liability associated with the collateral is recorded as an offset to the fair values of the interest rate options, which are recorded within other deferred charges on the condensed balance sheet, resulting in a net carrying amount of the interest rate options of $18,525,000 and $26,376,000 at June 30, 2012 and December 31, 2011, respectively.

We are deferring gains or losses from the change in fair value of each interest rate option 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 expected Department of Energy-guaranteed loan or alternative financing.

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 notional amount of forecasted debt issuances we have hedged in each year with LIBOR swaptions as of June 30, 2012.

Year	**LIBOR Swaption Notional Dollar Amount** (in thousands)
2013	$ 754,452
2014	563,425
2015	470,625
2016	310,533
2017	80,169
Total	**$2,179,204**

The table below reflects the fair value of derivative instruments and their effect on our unaudited condensed balance sheet as of June 30, 2012.

	Balance Sheet Location	**Fair Value**
		(dollars in thousands)
Total designated as hedges under authoritative guidance related to derivatives and hedging activities		
Liabilities:		
Natural Gas Swaps	Other current liabilities	**$ 4,265**
Total not designated as hedges under authoritative guidance related to derivatives and hedging activities		
Assets:		
Interest rate options	Other deferred charges	**$39,215**

The following table presents the gains and (losses) on derivative instruments recognized in margin or deferred on the balance sheet for the three and six months ended June 30, 2012.

Effect of Derivative Instruments on the Condensed Statement of Revenues and Expenses or Balance Sheet

	Statement of Revenues and Expenses or Balance Sheet Location	Three months ended	Six months ended
		(dollars in thousands)	
Designated as hedges under authoritative guidance related to derivatives and hedging activities			
Natural Gas Swaps	Purchased power	**$ 149**	**$ 149**
Natural Gas Swaps	Purchased power	**(3,095)**	**(5,502)**
Natural Gas Swaps	Regulatory assets	**990**	**990**
Natural Gas Swaps	Regulatory assets	**(11)**	**(11)**
Natural Gas Swaps	Receivables	**4,336**	**(5,244)**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities			
Interest rate options	Regulatory assets	**(27,645)**	**(60,785)**
Total losses on derivatives		**$(25,276)**	**$(70,403)**

(D) *Investments in Debt and Equity Securities.* Under the accounting guidance for Investments—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 97% of these gross unrealized losses were in effect for less than one year.

The following table summarizes the activities for available-for-sale securities as of June 30, 2012 and December 31, 2011.

		Gross Unrealized (dollars in thousands)		
June 30, 2012	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$149,018**	**$37,560**	**$ (6,900)**	**$179,678**
Debt	**162,427**	**9,025**	**(3,823)**	**167,629**
Other	**11,923**	**—**	**—**	**11,923**
Total	**$323,368**	**$46,585**	**$(10,723)**	**$359,230**

		Gross Unrealized (dollars in thousands)		
December 31, 2011	Cost	Gains	Losses	Fair Value
Equity	$149,263	$29,789	$ (9,996)	$169,056
Debt	160,218	18,021	(11,063)	167,176
Other	15,646	1,035	(1,541)	15,140
Total	$325,127	$48,845	$(22,600)	$351,372

(E) *Recently Issued or Adopted Accounting Pronouncements.* In May 2011, the Financial Accounting Standards Board issued "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards." The amendments change the wording used to describe many of the requirements in U.S. GAAP for measuring fair value and for disclosing information about fair value measurements, but do not result in a change in the application of ASC 820 "Fair Value Measurements." These changes were effective for us on January 1, 2012. Our adoption of this standard did not have a material effect on our condensed financial statements.

In June 2011, the FASB issued "Comprehensive Income (Topic 220) Presentation of Financial Statements" which amended certain provisions of ASC 220 "Comprehensive Income." These provisions change the presentation requirements for other comprehensive income and total comprehensive income and require one continuous statement or two separate but consecutive statements. Presentation of other comprehensive income in the statement of stockholders' equity is no longer permitted. These provisions are effective for fiscal and interim periods beginning after December 15, 2011. The adoption of these provisions did not have a material effect on our condensed financial statements.

In December 2011, the 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. This guidance is effective for our fiscal year ending December 31, 2013. We do not expect the adoption of this standard to have a material impact on our financial statements.

(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 Condensed 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 2011 Form 10-K.

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

	Accumulated Other Comprehensive Margin (Deficit) Three Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at March 31, 2011	$ (490)
Unrealized gain	613
Balance at June 30, 2011	$ 123
Balance at March 31, 2012	$1,327
Unrealized gain	119
Balance at June 30, 2012	**$1,446**

	Accumulated Other Comprehensive Margin (Deficit) Six Months Ended
	(dollars in thousands)
	Available-for-sale Securities
Balance at December 31, 2010	$ (469)
Unrealized gain	592
Balance at June 30, 2011	$ 123
Balance at December 31, 2011	$ 618
Unrealized gain	828
Balance at June 30, 2012	**$1,446**

(G) *Contingencies and Regulatory Matters.*

Nuclear Construction

We, along with Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton, the "Co-owners," 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.

The Co-owners, Westinghouse Electric Company LLC and Stone & Webster, Inc., the "Contractor," have established both informal and formal dispute resolution procedures in accordance with the Engineering, Procurement and Construction Contract to design, engineer, procure, construct, and test Vogtle Units No. 3 and No. 4 in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, and the Contractor have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and Georgia Power, on behalf of the Co-owners, are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

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 air and water quality requirements which, among other things, regulate emissions of pollutants, such as particulate matter, sulfur dioxide, nitrogen oxides and mercury into the air and discharges of other pollutants, including heat, into waters of the United States, which represent significant future risks and uncertainties. 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. Finally, we are subject to federal, state and local waste disposal requirements that regulate the manner of transportation, storage and disposal of various types of waste.

In general, environmental requirements are becoming increasingly stringent. Any new requirements in the future but not in existence now may substantially increase the cost of electric service by requiring changes in the design or operation of existing facilities or changes or delays in the location, design, construction or operation of new facilities. Failure to comply with any new requirements could result in the imposition of civil and criminal penalties as well as the complete shutdown of individual generating units not in compliance. Certain of our debt instruments and credit agreements 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 and regulations. We believe that we are in compliance with those environmental regulations currently applicable to our business and operations. Should we fail to be in compliance with these requirements, or any new requirements, it would constitute a default under such debt instruments and credit agreements. Although it is our intent to comply with applicable current and future regulations, we cannot provide assurance that we will always be in compliance with such requirements.

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.

We are currently not subject to any environmental loss contingencies for which we believe it is probable or reasonably possible that a loss has been incurred that would be material to our financial position, results of operations or cash flows.

(H) *Restricted Cash.* At June 30, 2012 and December 31, 2011, we had restricted cash totaling $21,305,000 and $43,683,000, respectively, of which $20,692,000 and $43,070,000 was classified as long-term. The long-term restricted cash balance at June 30, 2012 and December 31, 2011 consisted primarily of funds posted as collateral by counterparties to our interest rate options. The current portion of restricted cash at June 30, 2012 and December 31, 2011 consists of clean renewable energy bond proceeds on deposit with CoBank, ACB to fund a qualifying project at the Rocky Mountain Pumped Storage Hydroelectric Facility.

(I) *Restricted Short-term Investments.* At June 30, 2012 and December 31, 2011, we had $63,075,000 and $106,676,000, 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 June 30, 2012 and December 31, 2011.

	2012	2011
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt[(a)]	**$ 92,428**	$ 98,538
Amortization on capital leases[(b)]	**37,615**	46,627
Outage costs[(c)]	**36,730**	42,866
Interest rate swap termination fees[(d)]	**19,321**	21,316
Asset retirement obligations[(e)]	**21,069**	29,341
Depreciation expense[(f)]	**50,497**	51,209
Deferred charges related to Vogtle Units No. 3 and No. 4 training costs[(g)]	**21,391**	17,602
Interest rate options cost[(h)]	**61,774**	30,735
Deferral of effects on net margin—Smith Energy Facility[(k)]	**13,886**	3,536
Other regulatory assets[(i)]	**8,791**	9,777
Total Regulatory Assets	**$363,502**	$351,547
Regulatory Liabilities:		
Accumulated retirement costs for other obligations[(e)]	**$ 31,829**	$ 32,687
Net benefit of Rocky Mountain transactions[(j)]	**46,187**	47,783
Deferral of effects on net margin—Hawk Road Energy Facility[(k)]	**11,554**	15,811
Major maintenance sinking fund[(l)]	**28,921**	28,524
Deferred debt service adder[(m)]	**42,537**	37,586
Other regulatory liabilities[(i)]	**1,450**	1,609
Total Regulatory Liabilities	**$162,478**	$164,000
Net Regulatory Assets	**$201,024**	$187,547

(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 31 years.

(b) Recovery over the remaining life of the leases through 2031. See Note N for lease extensions.

(c) Consists of both coal-fired and nuclear refueling outage costs. These outage costs are amortized on a straight-line basis to expense over an 18 to 24-month period.

(d) Represents amount paid on settled interest rate swaps arrangements that are being amortized over the remaining life of the refunded variable rate bonds or 2016 and 2019, respectively.

(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) 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 over the life of the units.

(h) Deferral of net loss (gains) 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 DOE-guaranteed loan.

(i) The amortization period for other regulatory assets range up to 37 years and the amortization period of other regulatory liabilities range up to 7 years.

(j) Net benefit associated with Rocky Mountain lease transactions is amortized to income over the 30-year lease-back period. See Note P regarding events subsequent to the balance sheet date.

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

(l) Represents collections for future major maintenance costs that will offset major maintenance expenses when incurred.

(m) Collections to fund debt payments in excess of depreciation expense through the end of 2025.

(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 June 30, 2012, member power bill prepayments as reflected on the unaudited condensed balance sheet, including unpaid discounts, were $93,988,000, of which, $56,763,000 is classified as a current liability and $37,225,000 as deferred credits and other liabilities. The prepayments are being applied against members' power bills through November 2017, with the majority of the remaining balance scheduled to be applied by the end of 2013.

(L) *Debt.* For the six month period ended June 30, 2012, we received advances on Rural Utilities Service-guaranteed/Federal Financing Bank loans totaling $69,139,000 for general and environmental improvements at existing plants.

(M) *Sales to Non-Members.* For the three-month and six-month periods ended June 30, 2012, we had $37,220,000 and $61,214,000, respectively, of sales to non-members. These sales 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, formerly known as the Murray Energy Facility, to Georgia Power through May 31, 2012, as well as energy sales to other non-members from Smith Units No. 1 and No. 2.

(N) *Capital leases.* In 1985, we sold and subsequently leased back from four purchasers their 60% undivided ownership interest in Scherer Unit No. 2. On June 14, 2012, under the renewal provisions of the leases, we executed irrevocable notice of renewal to extend the leases beyond their base terms, for a period of 14.5 years, through December 31, 2027, for three of the leases and for a period of 18 years, through December 31, 2031, for one of the leases.

At June 30, 2012, we recorded the impact of the lease extensions which resulted in an increase in the capital asset and lease obligation for the Scherer 2 lease. The lease extensions did not have a material effect on our unaudited condensed financial statements. Leasehold improvements will be amortized over the extended lease terms.

(O) *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.

In 2007, the U.S. Court of Federal Claims found in favor of Southern Company and awarded damages in the amount of $59,900,000 representing substantially all of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Hatch and Plant Vogtle. Our share of the award was $17,980,000. In 2008, the government filed an appeal and, on March 11, 2011, the U.S. Court of Appeals for the Federal Circuit remanded the Georgia Power portion of the proceeding back to the U.S. Court of Federal Claims for reconsideration of the damages amount in light of the spent nuclear fuel acceptance rates adopted in a separate proceeding by the U.S. Court of Appeals for the Federal Circuit.

On April 5, 2012, the U.S. Court of Federal Claims issued a final order for judgment in favor of Georgia Power and awarded $54,017,000 in damages, of which our ownership share was approximately $16,205,000. The effects of the judgment are reflected in the unaudited financial statements for the quarter ended June 30, 2012 and resulted in a $9,679,000 reduction of operating expenses and a $6,526,000 reduction to plant in service.

In 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim). The complaint does not contain any specific dollar amounts for recovery of damages. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of June 30, 2012.

For a more information regarding the nuclear fuel costs and litigation, see Note 1 of "Item 8—Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements" in our 2011 Form 10-K.

(P) *Subsequent Events.* In December 1996 and January 1997, we entered into six long-term lease transactions relating to our 74.61% undivided interest in Rocky Mountain. In each transaction, we leased a portion of our undivided interest in Rocky Mountain to six separate owner trusts for the benefit of three investors for a term equal to 120% of the estimated useful life of Rocky Mountain.

On July 12, 2012, we terminated three of the six lease transactions prior to the end of their lease terms. These three leases were each owned by a separate owner trust for the benefit of one of the three investors, representing approximately 69% of the original six lease transactions. In connection with the termination, we incurred termination costs of approximately $17,200,000 and recognized $31,900,000 of the deferred net benefit associated with the terminated leases, resulting in a net gain on termination of $14,700,000 which we recognized in income in July 2012. The termination of these leases also results in a $94,500,000 decrease in the Deposit on Rocky Mountain transactions and Obligation under Rocky Mountain transactions from the amounts reflected in our unaudited condensed balance sheet at June 30, 2012.

For a more detailed discussion of the Rocky Mountain lease transactions, see Note 2 to "Item 8—Financial Statements and Supplementary Data—Notes to Consolidated Financial Statements" in our 2011 on Form 10-K.

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 39 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.

Forward-Looking Statements and Associated Risks

This Quarterly Report on Form 10-Q contains forward-looking statements, including statements regarding, among other items, (i) anticipated financing transactions by us, (ii) our future capital expenditure requirements and funding sources and (iii) achievement of a margins for interest ratio at the minimum requirement contained in our first mortgage indenture and, in the case that our board of directors approves a budget for a particular fiscal year that seeks to achieve a higher margins for interest ratio, such higher board-approved margins for interest ratio. These forward-looking statements are based largely on our current expectations and are subject to a number of risks and uncertainties, some of which are beyond our control. For a discussion of some factors that could cause actual results to differ materially from those anticipated by these forward-looking statements, see "Item 1A—RISK FACTORS" in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011. In light of these risks and uncertainties, there can be no assurance that events anticipated by the forward-looking statements contained in this Quarterly Report on Form 10-Q will in fact transpire.

Results of Operations

For the Three and Six Months Ended June 30, 2012 and 2011

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 this period of generation facility construction and acquisition, our board of directors approved budgets for 2011 and 2012 to achieve a 1.14 margins for interest ratio. As our construction and acquisition program evolves, 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 the 1.10 margins for interest ratio required under our first mortgage indenture.

Our net margin for the three-month and six-month periods ended June 30, 2012 was $10.9 million and $24.4 million compared to $12.7 million and $28.8 million for the same periods of 2011. We expect a net margin of $39.5 million for the year ending December 31, 2012 which will achieve, but not exceed, the targeted margins for interest ratio of 1.14.

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 or purchased resources or member-owned resources over which we have dispatch rights, and 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 5.3% and increased 1.4% in the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. Megawatt-hour sales to members increased 4.2% and 10.1% for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. The average total revenue per megawatt-hour from sales to members decreased 9.1% and 7.9% for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011.

The components of member revenues for the three-month and six month periods ended June 30, 2012 and 2011 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	**2012**	2011
Capacity revenues	**$ 173,446**	$ 171,478	**$ 347,633**	$ 343,479
Energy revenues	**137,037**	156,298	**258,080**	253,745
Total	**$ 310,483**	$ 327,776	**$ 605,713**	$ 597,224
Kilowatt-hours sold to members	**5,563,074**	5,341,362	**10,265,873**	9,324,218
Cents per kilowatt-hour	**5.58¢**	6.14¢	**5.90¢**	6.41¢

Energy revenues were 12.3% lower and 1.7% higher for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. Our average energy revenue per megawatt-hour from sales to members decreased 15.8% and 7.6% for the three-month and six-month periods ended June 30, 2012 as compared to the same periods of 2011. The decrease in energy revenues for the second quarter of 2012 as compared to the second quarter of 2011 resulted primarily from lower natural gas prices. Lower generation at Plant Wansley as well as the recognition of a $4.8 million reduction to nuclear fuel expense for the nuclear fuel disposal settlement with the Department of Energy also contributed to the reduction in total fuel costs. The decrease in total fuel costs was offset somewhat by higher generation from our gas-fired and nuclear facilities. For a discussion of total fuel costs and total generation, see "—*Operating Expenses.*" For a discussion of the Department of Energy nuclear fuel disposal settlement see Note O of Notes to Unaudited Condensed Financial Statements.

Sales to Non-Members. Sales to non-members for the three-month and six-month periods ended June 30, 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, formerly known as the Murray Energy Facility, to Georgia Power through May 31, 2012, as well as energy sales to other non-members from Smith Units No. 1 and No. 2. The decrease during the second quarter of 2012 versus the same period of 2011 was primarily due to lower capacity payments from Georgia Power after the agreement described above expired. We acquired Smith in April 2011.

Operating Expenses

Operating expenses for the three-month and six-month periods ended June 30, 2012 decreased 10.6% and increased 3.8%, respectively, compared to the same periods of 2011. The decrease in operating expenses during the second quarter of 2012 as compared to the same quarter of 2011 was primarily due to lower fuel and depreciation and amortization costs. The increase for the six-month period ended June 30, 2012 as compared to the same period of 2011 was primarily due to higher fuel, producuion and purchased power costs.

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

	Three Months Ended June 30,			
	2012		2011	
Fuel Source	**Cost**	**Generation**	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal	**$ 64,883**	**2,069,400**	$ 72,342	2,315,372
Nuclear	**17,702**	**2,612,822**	18,373	2,308,955
Gas	**53,197**	**2,267,328**	70,037	1,732,957
Pumped Storage	**567**	**312,473**	603	246,712
	$136,349	**7,262,023**	$161,355	6,603,996
	Cost	**Purchased**	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power	**$ 14,660**	**61,400**	$ 13,600	39,471

	Six Months Ended June 30,			
	2012		2011	
Fuel Source	**Cost**	**Generation**	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal	**$117,878**	**3,748,595**	$122,906	3,997,491
Nuclear	**38,033**	**5,046,539**	34,515	4,705,954
Gas	**86,075**	**3,663,540**	75,128	1,755,868
Pumped Storage	**1,183**	**512,973**	1,255	429,864
	$243,169	**12,971,647**	$233,804	10,889,177
	Cost	**Purchased**	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power	**$ 29,183**	**106,504**	$ 25,155	60,678

For the three-month and six-month periods ended June 30, 2012, total fuel costs decreased 15.5% and increased 4.0% and total megawatt-hour generation increased 10.0% and 19.1%, respectively, compared to the same periods of 2011. Average fuel costs per megawatt-hour decreased 23.2% and 12.7% in the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. The decrease in total fuel costs during the three-month period ended June 30, 2012 compared to the same period of 2011 was primarily due to lower natural gas prices and lower generation at Plant Wansley. The lower generation at Plant Wansley was primarily driven by the availability of more economical generation from our natural gas-fired facilities. The recognition of a $4.8 million expense reduction related to the nuclear fuel disposal settlement also contributed to lower fuel costs for the period though this reduction was substantially offset by higher nuclear generation. The increase in total fuel costs for the six-month period ended June 30, 2012 compared to the same period of 2011 was primarily due to an increase in natural gas-fired generation of 1,907,0000 megawatt-hours. The increase in generation for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011 resulted from increased natural gas-fired generation from Smith which was sold to non-members and generation from Chattahoochee Energy Facility which was sold to our members. As discussed previously, Smith was acquired in April 2011 and Chattahoochee was unavailable during the first quarter of 2011. An increase in nuclear generation also contributed to the year-to-date higher total fuel costs. The decrease in average fuel costs per megawatt-hour of generation for 2012 compared to 2011 has been driven primarily by a significant decline in natural gas prices, which has made natural gas-fired generation resources a more economical and cost-effective source of energy generation than in prior years. The increase in nuclear generation, which is our most economical energy generation, contributed to the decline as well.

Total production costs decreased 0.02% and increased 5.2% for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. While production costs varied only slightly for the second quarter of 2012 compared to the same period 2011, higher general operation maintenance costs at Plants Vogtle and Hatch were offset by recognition of a $3.0 million expense reduction from the nuclear fuel disposal settlement. The increase for the six-month period ended June 30, 2012 compared to the same period of 2011 was primarily due to operation and maintenance expenses incurred at Smith, increased general operations and maintenance expenses at Plants Vogtle and Hatch and higher operations and maintenance expenses at Chattahoochee. These increases were offset somewhat by lower production costs for the Hawk Road Energy Facility as production costs for Hawk Road in the first quarter of 2011 included expenses for planned outage work and for repair of a damaged transformer.

Depreciation and amortization costs decreased 20.4% and 0.3% for the three-month and six-month periods ended June 30, 2012, respectively, compared to the same periods of 2011. The decrease for the second quarter of 2012 as compared to the same period of 2011 resulted primarily from lower amortization costs in 2012 for the intangible asset associated with the purchase and sale agreement with Georgia Power acquired as part of the Smith acquisition. For the six-month period ended June 30, 2012 compared to the same period of 2011, the decrease in amortization costs due to expiration of the Georgia Power agreement was mostly offset by six months of Smith depreciation expense in 2012 versus three months of depreciation expense in 2011.

Total purchased power costs increased 7.8% and 16.0%, respectively, for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. The increase in purchased power costs was primarily due to higher realized losses incurred for natural gas financial contracts utilized for managing exposure to fluctuations in the market prices of natural gas.

The effect on net margin for Hawk Road and Smith 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. If any of our members subscribed to Smith elect to take energy from Smith prior to 2016, the deferral of the effect on net margin would terminate for that member and the amortization of that member's deferral would commence immediately. The changes in cost deferrals in 2012 compared to 2011 resulted from the Hawk Road and Smith production costs discussed above.

Other Income

Investment income increased 12.0% and 11.8% for the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011 primarily due to increased investment income resulting from higher funds deposited in the Rural Utilities Service Cushion of Credit Account.

Interest charges

Interest expense increased by 9.1% and 8.3% in the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011. This increase is primarily due to the increased debt issued to finance the construction of Vogtle Units No. 3 and No. 4.

Allowance for debt funds used during construction increased by 12.8% and 22.6% in the three-month and six-month periods ended June 30, 2012 compared to the same periods of 2011 primarily due to construction expenditures for Vogtle Units No. 3 and No. 4.

Financial Condition

Balance Sheet Analysis as of June 30, 2012

Assets

Cash used for property additions for the six-month period ended June 30, 2012 totaled $346.7 million. Of this amount, approximately $164 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4. The remaining expenditures were for purchases of nuclear fuel, environmental control systems being installed primarily at Plant Scherer and for normal additions and replacements to existing generation facilities.

The $63.1 million of restricted short-term investments at June 30, 2012 represented 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.

Receivables increased by $32.7 million as of June 30, 2012 compared to December 31, 2011. The December 31, 2011 receivables balance included $17.7 million of credits available to the members for a board approved reduction to 2011 revenue requirements as a result of margins collected in excess of our 2011 target. A portion of the increase in receivables was due to these credits being utilized by the members during the first quarter of 2012. The receivable for amounts billed or billable to the members for their monthly power bills also increased by $18.5 million in June 2012 compared to December 2011 due to higher energy costs in June 2012, which was a result of increased generation. In addition, power sales to non-members contributed to $7.4 million of the increase in receivables. Offsetting the increase was a decrease in the receivable balance for certain project costs written off in December 2011, for which a receivable from the members was recorded at December 31, 2011.

Other deferred charges decreased $25.2 million as of June 30, 2012 compared to December 31, 2011 due to an $8.8 million decrease in Georgia Power related deferred equipment prepayments that were expensed or capitalized in connection with a planned outage at Hatch Unit No. 1 that occurred in the first quarter of 2012 and an $8.4 million decrease in the amortized value of the intangible asset associated with the purchase and sale agreement with Georgia Power acquired as part of the 2011 Smith acquisition. Also contributing to the decrease was a $7.8 million decrease in the carrying amount of our interest rate hedges, which was impacted by a $30.2 million increase in the unrealized loss associated with the hedges and an offsetting $22.4 million decrease in counterparty collateral postings as of June 30, 2012 versus December 31, 2011.

Equity and Liabilities

Short-term borrowings for the six-month period ended June 30, 2012 increased $187.0 million. The increase was primarily due to the issuance of commercial paper to fund capital expenditures related to Vogtle Units No. 3 and No. 4.

Accounts payable decreased $61.8 million as of June 30, 2012 compared to December 31, 2011 primarily due to a $75.8 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. Offsetting the decrease was a $12.4 million increase in the energy related costs in June 2012 as a result of increased generation.

Member power bill prepayments represent funds received from the members for prepayment of their monthly power bills. At June 30, 2012, $56.8 million of member power bill prepayments was classified as a current liability and $37.2 million was classified as a long-term liability. During the six-month period ended June 30, 2012, approximately $17.6 million of prepayments were received from the members and approximately $26.0 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, the "Co-owners," 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. 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 2011 Form 10-K.

Westinghouse Electric Company LLC and Stone & Webster, Inc., together, the "Contractor," and the Co-owners have established both informal and formal dispute resolution procedures in accordance with the Engineering, Procurement and Construction Contract to design, engineer, procure, construct, and test Vogtle Units No. 3 and No. 4 in order to resolve issues arising during the course of constructing a project of this magnitude. Georgia Power, on behalf of the Co-owners, and the Contractor have successfully initiated both formal and informal claims through these procedures, including ongoing claims, to resolve disputes and expect to resolve any existing and future disputes. When matters are not resolved through these procedures, the parties may proceed to litigation. The Contractor and Georgia Power, on behalf of the Co-owners, are involved in litigation with respect to certain claims that have not been resolved through the formal dispute resolution process.

During the course of construction activities, issues have arisen that may impact the project budget and schedule. The most significant issues relate to costs associated with design changes to the Westinghouse AP1000 Design Certification 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. Georgia Power, on behalf of the Co-owners, and the Contractor have begun negotiations regarding these issues, including the assertion by the Contractor that the Co-owners are responsible for these costs under the terms of the contract. Through correspondence sent to the Co-owners, the Contractor provided its initial estimate of its proposed adjustment to the contract price and has initiated the formal dispute resolution process. Based on our ownership interest, the Contractor's estimated adjustment attributable to us regarding these issues is approximately $280 million in 2008 dollars with respect to these issues. Georgia Power, on behalf of the Co-owners, has not agreed with the amount of these proposed adjustments or that the Co-owners have responsibility for any costs related to these issues. While the formal dispute resolution process has been initiated, Georgia Power expects negotiations with the Contractor to continue over the next several months with respect to cost and schedule during which time the parties will attempt to reach a mutually acceptable compromise of their positions. If a compromise cannot be reached, formal dispute resolution, including litigation, may follow. Georgia Power, on behalf of the Co-owners, intends to vigorously defend its positions. In connection with these negotiations, the Co-owners are evaluating whether maintaining the currently scheduled commercial operation dates of 2016 and 2017 remains in the best interest of their customers. Additional claims by the Contractor or Georgia Power, on behalf of the Co-owners, are expected to arise throughout the construction of Vogtle Units No. 3 and No. 4.

In addition, there are processes in place to assure compliance with the design requirements specified in the DCD and the combined licenses, including rigorous inspection by Southern Nuclear Operating Company and the Nuclear Regulatory Commission that occurs throughout construction. During a routine inspection in April 2012, the Nuclear Regulatory Commission identified that certain details of the rebar construction in the Vogtle Unit No. 3 nuclear island were not consistent with the DCD. In May 2012, Southern Nuclear received an official notice of violation relating to these findings from the Nuclear Regulatory Commission. The design changes were determined to have minimal safety significance and, on August 1, 2012, Southern Nuclear filed a license amendment request with the Nuclear Regulatory Commission to clarify that the nuclear island concrete and rebar construction will conform to Nuclear Regulatory Commission requirements. On August 2, 2012, the Nuclear Regulatory Commission accepted the filing as sufficient to allow review, and has indicated it has no objection with Southern Nuclear proceeding with installation as proposed in the amendment request, on an at-risk basis pending the outcome of a detailed review. Various inspection and other issues are expected to arise from time to time as construction proceeds, which may result in additional license amendments or require other resolution.

On February 16, 2012, a group of four plaintiffs who had intervened in the Nuclear Regulatory Commission's combined license proceedings for Vogtle Units No. 3 and No. 4 filed a petition in the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review and a stay of the Commission's issuance of the combined licenses. In addition, on February 16, 2012, a group of nine plaintiffs filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit seeking judicial review of the Commission's certification of the DCD. On April 3, 2012, the Court granted a motion filed by these two groups to consolidate their challenges. On April 18, 2012, another group of petitioners filed a motion to stay the effectiveness of the order issuing the combined licenses for Vogtle Units No. 3 and No. 4 with the U.S. District Court for the District of Columbia. On July 11, 2012, the U.S. Court of Appeals for the District of Columbia Circuit denied the petitioners' motion to stay the effectiveness of the combined licenses. Georgia Power, on behalf of the Co-owners, has intervened and intends to vigorously contest these petitions.

There are other pending technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4. Similar additional challenges at both the state and federal level are expected as construction proceeds.

The ultimate outcome of these matters cannot be determined at this time. See "Item 1A—RISK FACTORS" in our 2011 Form 10-K for a discussion of certain risks associated with the licensing, construction and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world.

As of June 30, 2012, our total capitalized costs to date for Vogtle Units No. 3 and No. 4 were $1.5 billion.

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 February 16, 2012, EPA issued the final Mercury and Air Toxics Standards (MATS) rule for new and existing coal and oil-fired electric utility steam generating units, which is somewhat less stringent than proposed. The MATS rule establishes limits for emissions of heavy metals, including mercury. In order to comply with the MATS rule, the potential need to install baghouses at Plant Wansley at an approximate cost of $150 million was considered. See "Item 1—BUSINESS—ENVIRONMENTAL AND OTHER REGULATION—Air Quality—*Mercury and Air Toxics Standards and State Mercury Rule*" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2011 Form 10-K. Additional evaluation has shown that compliance with the MATS rule can be achieved using an alternative mercury emissions control technology. We anticipate using this alternative technology, which will decrease projected capital expenditures by more than $100 million over the next four years. Although challenges to the MATS rule have been filed, we cannot predict the outcome of any litigation in this matter, including whether such outcome will further affect operations at Plants Wansley or Scherer.

On June 26, 2012, the U.S. Court of Appeals for the District of Columbia Circuit ruled in favor of EPA on the principal litigation challenging several of EPA's greenhouse gas (GHG) rules. This decision will become final unless the Court agrees to a rehearing or the U.S. Supreme Court agrees to its review. It is not known whether such actions will be requested, and we cannot predict the ultimate outcome of any appeal that might be filed. Therefore, we continue to be regulated under EPA's Prevention of Significant Deterioration regulations for emissions of GHGs and any major modifications at our facilities will need to be permitted under these requirements.

On June 29, 2012, EPA proposed revisions to certain national ambient air quality standards (NAAQS) for fine particulate matter and plans to finalize the standards by December 14, 2012. The proposed standards are more stringent than the existing fine particulate matter NAAQS and one of them would target improving visibility in urban areas. The impact of such standards, if finalized, on our owned and co-owned power plants cannot be determined at this time.

For further discussion regarding potential effects on our business from environmental regulations, including potential capital requirements, see "Item 1—BUSINESS—ENVIRONMENTAL AND OTHER REGULATION," "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 2011 Form 10-K.

Liquidity

At June 30, 2012, we had $1.4 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $409.3 million in cash and cash equivalents and $1.0 billion of unused and available committed credit arrangements.

On June 30, 2012, 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 6/30/2012	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit[(1)]	$1,265	$ 481[(2)]	June 2015
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	34[(3)]	December 2013
Secured facilities:			
CoBank Line of Credit	150	150	November 2012
CFC Line of Credit[(4)]	250	250	December 2013
Total	**$1,925**	**$1,025**	

(1) This credit facility is syndicated among fourteen banks led by Bank of America as administrative agent.

(2) Of the portion of this facility that is unavailable, $648 million is dedicated to support commercial paper we have issued and $136 million relates to letters of credit issued under this facility to support variable rate demand bonds.

(3) 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 $2.5 million relates to letters of credit issued to post collateral to third parties.

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

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

We are currently negotiating with CoBank, ACB to replace our existing $150 million secured line of credit with a $150 million unsecured line of credit led by CoBank and syndicated among a group of participant banks. We expect to have the new facility in place prior to the expiration of the existing facility in late November 2012.

Due to the significant expenditures related to environmental compliance projects and new generation facilities, we have been funding our capital requirements through a combination of funds generated from operations and interim and long-term borrowings. In particular, we are using commercial paper, backed by the syndicated line of credit, to provide interim financing for: (i) the construction of Vogtle Units No. 3 and No. 4, (ii) a portion of the cost to acquire Smith, and (iii) the upfront payments made in connection with our interest rate hedging program, until long-term financing for these items is put in place.

We have the flexibility to use the syndicated line of credit for several purposes, including borrowing for general corporate purposes, issuing letters of credit and backing up outstanding commercial paper. Pursuant to our board authorization, we can issue commercial paper in amounts that do not exceed the amount of our committed backup line of credit, thereby providing 100% dedicated support for any commercial paper outstanding.

Like the syndicated line of credit, funds may be advanced under the $110 million line of credit with National Rural Utilities Cooperative Finance Corporation (CFC) and under the lines of credit with JPMorgan Chase Bank and CoBank for general working capital purposes. In addition, under those same credit facilities we have the ability to issue letters of credit totaling $910 million in the aggregate, of which $658 million remained available at June 30, 2012. However, amounts related to issued letters of credit reduce the amount that would otherwise be available to draw for working capital needs. Also, any amounts drawn under the syndicated line for working capital or related to issued letters of credit will reduce the amount of commercial paper that we can issue.

Several of our credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At June 30, 2012, the required minimum level was $598 million and our actual patronage capital was $658 million. Additional covenants contained in several of our credit facilities limit the amount of secured indebtedness and unsecured indebtedness we can have outstanding. At June 30, 2012, the most restrictive of these covenants limits our secured indebtedness to $8.5 billion and our unsecured indebtedness to $4.0 billion. At June 30, 2012, we had $5.6 billion of secured indebtedness and $1.0 billion of unsecured indebtedness outstanding, which was well within the covenant thresholds.

We also have a power bill prepayment program that provides us with an additional source of liquidity. Under the program, members can prepay their power bills from us at a discount for an agreed upon number of months in advance, after which the prepayments are credited against the participating members' monthly power bills. The discount is comparable to our avoided cost of borrowing. As of June 30, 2012, the balance of member prepayments received but not yet credited to their power bills was $94.0 million. We expect to apply the prepayments against the participating members' power bills through November 2017, with the majority of the remaining balance scheduled to be applied by the end of 2013. For more information regarding the power bill prepayment program, see Note K of Notes to Unaudited Condensed Financial Statements.

At June 30, 2012, current assets included $63.1 million of restricted short-term investments pursuant to deposits made to a Rural Utilities Service Cushion of Credit Account. Deposits in the Cushion of Credit Account are made voluntarily and earn a guaranteed rate of interest of 5% per annum. The funds in the account, including interest thereon, can only be applied to debt service on Rural Utilities

Service notes and Rural Utilities Service-guaranteed Federal Financing Bank notes. Our decisions regarding when to apply the funds are guided by the interest rate environment and our anticipated liquidity needs.

Financing Activities

First Mortgage Indenture. At June 30, 2012, we had $5.5 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 2011 Form 10-K for a further discussion of our first mortgage indenture.

Bond Financing. On April 2, 2012, we closed a $32.4 million financing transaction that included two components. In one component the Development Authority of Monroe County issued, on our behalf, $10.1 million of term rate pollution control revenue bonds for the purpose of refinancing a like amount of pollution control revenue bonds previously issued by the authority on our behalf that had matured. This tax-exempt debt is secured under our first mortgage indenture. The second component entailed a remarketing of $22.3 million of pollution control bonds issued previously on our behalf by the Development Authority of Burke County due to a mandatory tender of these bonds which were originally issued in a term rate period that ended March 31, 2012. Both components now bear interest in a term rate period that ends on February 28, 2013.

In a separate transaction on April 2, 2012, Georgia Transmission Corporation refinanced $40.2 million of pollution control bonds for which we were secondarily obligated. Upon this refinancing, we were no longer obligated for these bonds or any other of Georgia Transmission's debt obligations. For further discussion regarding our prior obligations related to Georgia Transmission, see "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION—Financial Condition—*Off-Balance Sheet Arrangements—Georgia Transmission Debt Assumption*" and Note 10 to "Item 8—FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA—Notes to Consolidated Financial Statements" in our 2011 Form 10-K.

Rural Utilities Service-Guaranteed Loans. We have six approved Rural Utilities Service-guaranteed loans, being funded through the Federal Financing Bank, totaling $1.7 billion that are in various stages of being drawn down, with $1.0 billion 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 70% of the estimated $4.2 billion cost to construct our 30% undivided share of Vogtle Units No. 3 and No. 4, not to exceed $3.057 billion. 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 anticipate that any project costs not funded under the Department of Energy loan guarantee program would be financed through the issuance of taxable bonds.

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.*"

Off-Balance Sheet Arrangements

Rocky Mountain Lease Arrangements. As discussed in our 2011 Form 10-K, in December 1996 and January 1997, we entered into six long-term lease transactions relating to our 74.61% undivided interest in the Rocky Mountain Pumped-Storage Hydroelectric Plant. In each transaction, we leased a portion of our undivided interest to six separate owner trusts for the benefit of three investors for a term equal to 120% of the estimated useful life of Rocky Mountain.

On July 12, 2012, we terminated three of the six lease transactions prior to the end of their lease terms. These three leases were each owned by a separate owner trust for the benefit of one of the three investors, and represented approximately 69% of the six original lease transactions. The termination of these three leases significantly reduced our exposure to the four credit counterparties participating in the lease transactions. Our negotiated cost to terminate the leases represented a substantial discount to the amounts due pursuant to an early termination event under the operative lease documents.

As a result of these lease terminations:

- the Deposit on Rocky Mountain transactions and Obligations under Rocky Mountain transactions as reflected on our balance sheets (representing the equity deposits with AIG) decreased from $137 million at June 30, 2012 to approximately $42 million;
- AIG's required collateral balance related to the equity deposits decreased from $144 million to approximately $45 million;
- the annual rental payments due from us to RMLC in 2013 will be reduced from $58 million to approximately $17 million;
- the fixed purchase price related to the purchase option at the end of the base lease term has decreased from $1.087 billion to approximately $326 million, of which the funding contribution pursuant to the payment undertaking agreements decreased from $715 million to approximately $211 million and the funding contribution pursuant to the equity funding agreements decreased from $372 million to approximately $115 million; and
- if RMLC's interest in the payment undertaking agreements and the corresponding lease obligations were reflected on our balance sheets, both the Deposit on Rocky Mountain transactions and the Obligation under Rocky Mountain transactions would be higher by approximately $210 million.

The termination of these leases had substantially no effect on our ownership, possession or use of Rocky Mountain. For additional information regarding the Rocky Mountain lease transactions, see "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Off-Balance Sheet Arrangements—Rocky Mountain Lease Arrangements*" in our 2011 Form 10-K and Note P of Notes to Unaudited Condensed Financial Statements.

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 June 30, 2012, 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.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to various actions and proceedings incidental to our normal business. Liability in the event of final adverse determination in any of these matters is either covered by insurance or, in the opinion of our management, after consultation with counsel, should not in the aggregate have a material adverse effect on our financial position, results of operations or cash flows.

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 2011 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
31.1	Rule 13a-14(a)/15d-14(a) Certification, by Thomas A. 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 Thomas A. 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 13, 2012 By: /s/ Thomas A. Smith

Thomas A. Smith
President and Chief Executive Officer
(Principal Executive Officer)

Date: August 13, 2012 /s/ Elizabeth B. Higgins

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