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

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

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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OGLETHORPE POWER CORPORATION
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2011

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Oglethorpe Power Corporation
Condensed Balance Sheets
September 30, 2011 and December 31, 2010

	(dollars in thousands)	
	2011	2010
	(Unaudited)	
Assets		
Electric plant:		
In service	**$ 7,319,697**	$ 6,672,253
Less: Accumulated provision for depreciation	**(3,299,200)**	(3,101,731)
	4,020,497	3,570,522
Nuclear fuel, at amortized cost	**275,626**	249,563
Construction work in progress	**1,614,300**	1,195,475
	5,910,423	5,015,560
Investments and funds:		
Decommissioning fund	**252,393**	265,483
Deposit on Rocky Mountain transactions	**129,894**	123,573
Investment in associated companies	**56,488**	56,125
Long-term investments	**77,221**	79,212
Other, at cost	**3,475**	3,570
	519,471	527,963
Current assets:		
Cash and cash equivalents, at cost	**410,461**	672,212
Restricted cash, at cost	**613**	6,300
Restricted short-term investments	**105,823**	97,286
Receivables	**141,143**	106,674
Inventories, at average cost	**203,772**	171,815
Prepayments and other current assets	**10,872**	13,416
	872,684	1,067,703
Deferred charges:		
Deferred debt expense, being amortized	**64,627**	59,202
Regulatory assets	**345,212**	311,136
Other	**42,492**	15,498
	452,331	385,836
	$ 7,754,909	$ 6,997,062

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

Oglethorpe Power Corporation
Condensed Balance Sheets
September 30, 2011 and December 31, 2010

	(dollars in thousands)	
	2011 (Unaudited)	2010
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 635,188**	$ 595,952
Accumulated other comprehensive margin (deficit)	**864**	(469)
	636,052	595,483
Long-term debt	**5,519,630**	4,657,127
Obligation under capital leases	**159,199**	179,288
Obligation under Rocky Mountain transactions	**129,894**	123,573
	6,444,775	5,555,471
Current liabilities:		
Long-term debt and capital leases due within one year	**136,923**	170,947
Short-term borrowings	**275,757**	305,959
Accounts payable	**119,839**	139,614
Accrued interest	**45,935**	76,435
Accrued and withheld taxes	**22,283**	27,171
Member power bill prepayments, current	**50,097**	71,496
Other current liabilities	**12,929**	18,567
	663,763	810,189
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**26,731**	28,587
Asset retirement obligations	**294,298**	280,496
Member power bill prepayments, non-current	**41,500**	41,000
Power sale agreement, being amortized	**58,482**	69,480
Regulatory liabilities	**175,621**	170,235
Other	**49,739**	41,604
	646,371	631,402
	$7,754,909	$6,997,062

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

Oglethorpe Power Corporation
Condensed Statements of Revenues and Expenses (Unaudited)
For the Three and Nine Months Ended September 30, 2011 and 2010

	(dollars in thousands)			
	Three Months		Nine Months	
	2011	2010	**2011**	2010
Operating revenues:				
Sales to Members	**$349,906**	$370,602	**$ 947,130**	$1,000,393
Sales to non-Members	**82,624**	796	**134,977**	1,188
Total operating revenues	**432,530**	371,398	**1,082,107**	1,001,581
Operating expenses:				
Fuel	**188,983**	160,174	**422,789**	383,750
Production	**90,101**	82,717	**269,154**	245,953
Depreciation and amortization	**49,835**	31,208	**133,708**	98,652
Purchased power	**20,925**	24,721	**46,080**	60,346
Accretion	**4,562**	4,282	**13,687**	12,848
Deferral of effect on net margin for Hawk Road and Murray Energy facilities	**13,240**	4,382	**2,168**	10,453
Total operating expenses	**367,646**	307,484	**887,586**	812,002
Operating margin	**64,884**	63,914	**194,521**	189,579
Other income:				
Investment income	**7,147**	7,950	**21,467**	23,103
Other	**1,651**	3,231	**6,974**	9,413
Total other income	**8,798**	11,181	**28,441**	32,516
Interest charges:				
Interest expense	**75,704**	65,946	**218,649**	197,089
Allowance for debt funds used during construction	**(17,835)**	(10,474)	**(50,816)**	(28,611)
Amortization of debt discount and expense	**5,405**	5,775	**15,893**	17,765
Net interest charges	**63,274**	61,247	**183,726**	186,243
Net margin	**$ 10,408**	$ 13,848	**$ 39,236**	$ 35,852

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

Oglethorpe Power Corporation
Condensed Statements of Patronage Capital and Membership Fees
and Accumulated Other Comprehensive Margin (Deficit) (Unaudited)
For the Nine Months Ended September 30, 2011 and 2010

(dollars in thousands)

	Patronage Capital and Membership Fees	Accumulated Other Comprehensive Margin (Deficit)	Total
Balance at December 31, 2009	$562,219	$(1,253)	$560,966
Components of comprehensive margin:			
Net margin	35,852	—	35,852
Unrealized gain on available-for-sale securities	—	1,085	1,085
Total comprehensive margin			36,937
Balance at September 30, 2010	$598,071	$ (168)	$597,903
Balance at December 31, 2010	$595,952	$ (469)	$595,483
Components of comprehensive margin:			
Net margin	39,236	—	39,236
Unrealized gain on available-for-sale securities	—	1,333	1,333
Total comprehensive margin			40,569
Balance at September 30, 2011	**$635,188**	**$ 864**	**$636,052**

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

Oglethorpe Power Corporation
Condensed Statements of Cash Flows (Unaudited)
For the Nine Months Ended September 30, 2011 and 2010

	(dollars in thousands)	
	2011	2010
Cash flows from operating activities:		
Net margin	**$ 39,236**	$ 35,852
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization, including nuclear fuel	**228,710**	186,056
Accretion cost	**13,687**	12,848
Amortization of deferred gains	**(4,245)**	(4,245)
Allowance for equity funds used during construction	**(2,034)**	(1,707)
Deferred outage costs	**(43,827)**	(25,229)
Deferral of effect on net margin for Hawk Road and Murray Energy Facilities	**2,168**	10,453
Gain on sale of investments	**(13,306)**	(12,013)
Regulatory deferral of costs associated with nuclear decommissioning	**5,825**	4,987
Other	**(5,971)**	(4,216)
Change in operating assets and liabilities:		
Receivables	**(29,995)**	(25,622)
Inventories	**2,250**	24,137
Prepayments and other current assets	**2,544**	(4,384)
Accounts payable	**10,407**	(2,487)
Accrued interest	**(30,500)**	(13,498)
Accrued and withheld taxes	**(5,197)**	(2,779)
Member power bill prepayments	**(20,899)**	(115,831)
Other current liabilities	**(5,046)**	(2,782)
Total adjustments	**104,571**	23,688
Net cash provided by operating activities	**143,807**	59,540
Cash flows from investing activities:		
Property additions	**(634,955)**	(524,334)
Plant acquisition	**(530,293)**	—
Activity in decommissioning fund—Purchases	**(828,008)**	(480,447)
—Proceeds	**823,598**	476,630
Decrease in restricted cash and cash equivalents	**5,687**	16,106
Increase in restricted short-term investments	**(8,537)**	(181)
Activity in investment in associated organizations—Purchases	**(4,634)**	(4,142)
—Proceeds	**4,556**	3,196
Activity in other long-term investments—Purchases	**(1,246)**	(4,313)
—Proceeds	**1,100**	3,100
Other	**(7,822)**	5,420
Net cash used in investing activities	**(1,180,554)**	(508,965)
Cash flows from financing activities:		
Long-term debt proceeds	**1,093,399**	222,631
Long-term debt payments	**(285,067)**	(222,265)
(Decrease) increase in short-term borrowings, net	**(30,202)**	297,413
Other	**(3,134)**	5,373
Net cash provided by financing activities	**774,996**	303,152
Net decrease in cash and cash equivalents	**(261,751)**	(146,273)
Cash and cash equivalents at beginning of period	**672,212**	579,069
Cash and cash equivalents at end of period	**$ 410,461**	$ 432,796
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 189,258**	$ 173,307
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	**$ (27,810)**	$ 95,797

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

(A) *General.* The condensed financial statements included in this report have been prepared by us pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the information furnished in this report reflects all adjustments (which include only normal recurring adjustments) and estimates necessary to fairly state, in all material respects, the results for the three- and nine-month periods ended September 30, 2011 and 2010. 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, 2010, as filed with the SEC. The results of operations for the three- and nine-month periods ended September 30, 2011 are not necessarily indicative of results to be expected for the full year. As noted in our 2010 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 2010 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 measurement 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 without adjustment 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 for the periods ended September 30, 2011 and December 31, 2010.

		Fair Value Measurements at Reporting Date Using		
	September 30, 2011	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	**$90,014**	$90,014	$ —	$ —
International equity	**38,186**	38,186	—	—
Corporate bonds	**45,827**	45,827	—	—
US Treasury and government agency securities	**38,581**	38,581	—	—
Agency mortgage and asset backed securities	**23,059**	23,059	—	—
Derivative instruments	**(1,032)**	—	—	(1,032)
Other	**17,757**	17,757	—	—
Bond, reserve and construction funds	**2,720**	2,720	—	—
Long-term investments	**77,221**	69,523	—	7,698[1]
Natural gas swaps	**(2,173)**	—	(2,173)	—

	December 31, 2010	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	$105,523	$105,523	$ —	$ —
International equity	43,619	43,619	—	—
Corporate bonds	53,847	53,847	—	—
US Treasury and government agency securities	47,649	47,649	—	—
Agency mortgage and asset backed securities	7,926	7,926	—	—
Derivative instruments	(452)	—	—	(452)
Other	7,371	7,371	—	—
Bond, reserve and construction funds	2,815	2,815	—	—
Long-term investments	79,212	70,541	—	8,671[(1)]
Natural gas swaps	(2,054)	—	(2,054)	—

(1) Represents auction rate securities investments we hold.

The following tables present the changes in our Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2011 and 2010.

	Three Months Ended September 30, 2011: Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at June 30, 2011	$ (505)	$8,048
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(527)	—
Impairment included in other comprehensive deficit	—	50
Liquidations	—	(400)
Balance at September 30, 2011	**$(1,032)**	**$7,698**

	Three Months Ended September 30, 2010	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at June 30, 2010	$(311)	$24,485
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(212)	—
Impairment included in other comprehensive deficit	—	9
Liquidations	—	(400)
Balance at September 30, 2010	$(523)	$24,094

	Nine Months Ended September 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)	(580)	—
Impairment included in other comprehensive deficit	—	127
Liquidations	—	(1,100)
Balance at September 30, 2011	**$(1,032)**	**$ 7,698**

	Nine Months Ended September 30, 2010	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at December 31, 2009	$(260)	$27,010
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(263)	—
Impairment included in other comprehensive deficit	—	184
Liquidations	—	(3,100)
Balance at September 30, 2010	$(523)	$24,094

The assets included in the "Long-term investments" column in each of the Level 3 tables above are auction rate securities. As a result of market conditions, including the failure of auctions for the auction rate securities in which we invested, the fair value of these auction rate securities was determined using an income approach based on a discounted cash flow model. The discounted cash flow model utilized projected cash flows at current interest rates, which was adjusted for illiquidity premiums based on discussions with market participants. At September 30, 2011, we held auction rate securities with maturity dates ranging from November 1, 2044 to December 1, 2045.

At December 31, 2010, we had a temporary impairment on our auction rate securities of $1,029,000. Based on the fair value of the auction rate securities held at September 30, 2011, we recorded a ($127,000) incremental adjustment to the temporary impairment. The temporary impairment is reflected in "Accumulated other comprehensive margin (deficit)" on the condensed balance sheet. The various assumptions we utilized to determine the fair value of our auction rate securities investments will vary from period to period based on the prevailing economic conditions. If the market for our auction rate securities investments should deteriorate, we may need to increase the illiquidity premium used in preparing a discounted cash flow model for these securities. A 25 basis point increase in the illiquidity premium used to determine the fair value of these investments at September 30, 2011, would have resulted in an additional decrease in the fair value of our auction rate securities investments by approximately $509,000.

As of September 30, 2011, these investments were rated A3 by Moody's Investors Service and AAA by Fitch. Therefore, it is expected that the investments will not be settled at a price less than par value. Because we do not intend to sell these securities unless we can recover our cost basis in a relatively short period of time, and it is not more likely than not that we will be required to sell the securities, we considered the investments to be temporarily impaired at September 30, 2011.

(C) *Disclosures about Derivative Instruments and Hedging Activities.* Our risk management committee provides general oversight over all risk management activities, including but not limited to, commodity trading and investment portfolio management. We use commodity trading derivatives, which are 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 treatment for energy costs which are flowed-through to our members, unrealized gains or losses on the natural gas swaps are reflected as an unbilled receivable. Within our nuclear decommissioning trust fund, derivatives including options, swaps and credit default swaps which are non-speculative, are 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 treatment, unrealized gains or losses from the decommissioning trust fund are recorded as an increase or decrease to the regulatory asset or liability.

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

At September 30, 2011, the estimated fair value of our natural gas contracts was an unrealized loss of approximately $2,173,000. See Note B for further discussion on fair value measurements of financial instruments.

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 manage credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement, and exposure monitoring and mitigation in our natural gas hedging portfolio.

It is possible that volatility in commodity prices could cause us to have credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations, we could suffer a financial loss. However, as of September 30, 2011, all of the counterparties with transaction amounts outstanding in our hedging portfolio are rated investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated investment grade.

We have entered into International Swaps and Derivatives Association agreements with our natural gas hedge counterparties that mitigate credit exposure by creating contractual rights relating to creditworthiness, collateral, termination and netting (which 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 counterparties' credit standing, including those experiencing financial problems, significant swings in credit default swap rates, credit rating changes by external rating agencies, or changes in ownership. 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 standing and credit ratings from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of September 30, 2011, neither we nor any counterparties were required to post credit support or collateral under any of these agreements. If the credit-risk-related contingent features underlying these agreements were triggered on September 30, 2011 due to our credit rating being downgraded below investment grade, we could have been required to post collateral or credit support totaling up to $2,173,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives as of September 30, 2011 that is expected to settle or mature each year:

Year	Natural Gas Swaps (MMBTUs) (in millions)
2011	0.57
2012	2.60
2013	0.54
Total	**3.71**

The table below reflects the fair value of derivative instruments and their effect on our unaudited condensed balance sheet as of September 30, 2011.

	Balance Sheet Location	Fair Value
		(dollars in thousands)
Designated as hedges under authoritative guidance related to derivatives and hedging activities:		
Assets		
Natural Gas Swaps	Receivables	**$ 2,173**
Total assets designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 2,173**
Liabilities		
Natural Gas Swaps	Other current liabilities	**$ 2,173**
Total liabilities designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 2,173**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities:		
Assets		
Nuclear decommissioning trust	Decommissioning fund	**$ 911**
Nuclear decommissioning trust	Decommissioning fund	**(1,943)**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**985**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**(1,456)**
Total not designated as hedges under authoritative guidance related to derivatives and hedging activities		**$(1,503)**

The following table presents the gains and (losses) on derivative instruments recognized in net margin for the three and nine months ended September 30, 2011.

Effect of Derivative Instruments on the Condensed Statement of Revenues and Expenses

	Statement of Revenues and Expenses Location	Three months ended	Nine months ended
		(dollars in thousands)	
Designated as hedges under authoritative guidance related to derivatives and hedging activities			
Natural Gas Swaps	Purchase power	**$ 99**	**$ 195**
Natural Gas Swaps	Purchase power	**(2,169)**	**(3,424)**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities			
Nuclear decommissioning trust	Investment income	**927**	**1,997**
Nuclear decommissioning trust	Investment income	**(661)**	**(1,233)**
Total losses on derivatives		**$(1,804)**	**$(2,465)**

(D) *Investments in Debt and Equity Securities.* Under the accounting guidance for investments in debt and equity securities, investment securities we hold are classified as either available-for-sale or held-to-maturity. Available-for-sale securities are carried at market value with unrealized gains and losses, net of any tax effect, added to or deducted from patronage capital. Unrealized gains and losses from investment securities held in the decommissioning fund, which are also classified as available-for-sale, are directly added to or deducted from deferred asset retirement obligations costs. Held-to-maturity securities are carried at cost. We owned no held-to-maturity securities as of September 30, 2011 and December 31, 2010. All realized and unrealized gains and losses were determined using the specific identification method. Approximately 84% of these gross unrealized losses were in effect for less than one year. These losses were primarily due to investments in equity securities held in the nuclear decommissioning trust fund. Consistent with our ratemaking, unrealized gains and losses from the decommissioning trust fund are recorded as an increase or decrease to the associated regulatory asset.

For those securities considered to be available-for-sale, the following table summarizes the activities for those securities as of September 30, 2011 and December 31, 2010:

		(dollars in thousands)		
		Gross Unrealized		
September 30, 2011	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$147,602**	**$20,430**	**$(14,928)**	**$153,104**
Debt	**156,235**	**10,779**	**(4,508)**	**162,506**
Other	**17,164**	**1,080**	**(1,520)**	**16,724**
Total	**$321,001**	**$32,289**	**$(20,956)**	**$332,334**

December 31, 2010	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
Equity	$137,492	$42,622	$(2,482)	$177,632
Debt	158,706	9,130	(4,879)	162,957
Other	7,035	3	(118)	6,920
Total	$303,233	$51,755	$(7,479)	$347,509

(E) *Recently Issued or Adopted Accounting Pronouncements.* In January 2010, the Financial Accounting Standards Board (FASB) issued Fair Value Measurements and Disclosures—Improving Disclosures about Fair Value Measurements. Effective March 31, 2011, the standard requires a reporting entity to present separately information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than a net basis) in the reconciliation for fair value measurements using significant unobservable inputs (Level 3). Our adoption of the standard did not have a material effect on our disclosures.

In April 2011, the FASB issued Fair Value Measurements: Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRSs). The amendments clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and include those that change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. The standard is effective for our fiscal year ending December 31, 2011. The adoption of the standard is not expected to have any impact on our results of operations, cash flows or financial condition.

In May 2011, the FASB issued Comprehensive Income: Presentation of Comprehensive Income. The standard requires that an entity present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. The standard is effective for our fiscal year ending December 31, 2012. Our adoption of the standard will not have a material effect on our disclosures.

In August 2011, the FASB issued Intangibles, Goodwill and Other: Testing Goodwill for Impairment. The amendments provide that an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances lead to a determination that is more likely than not that the fair value of a reporting unit is less than its carrying amount. If after assessing events or circumstances, an entity determines it is not more likely than not that the fair value of a reporting unit is less than its carrying amount, performing the two-step goodwill impairment test is unnecessary. If an entity concludes otherwise, the entity is required to perform the first step of the two-step goodwill impairment test by calculating the fair value of the reporting unit and comparing it with the carrying amount of the reporting unit. If the carrying amount exceeds the fair value, the second step of the goodwill impairment test to measure the amount of the loss is required. The standard is effective for our fiscal year ending December 31, 2011. We do not expect this standard to have an 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 accumulated 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 2010 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	Total
Balance at June 30, 2010	$(220)	$(220)
Unrealized gain	52	52
Balance at September 30, 2010	$(168)	$(168)
Balance at June 30, 2011	$ 123	$ 123
Unrealized gain	741	741
Balance at September 30, 2011	**$ 864**	**$ 864**

	Accumulated Other Comprehensive Margin (Deficit) Nine Months Ended	
	(dollars in thousands)	
	Available-for-sale Securities	Total
Balance at December 31, 2009	$(1,253)	$(1,253)
Unrealized gain	1,085	1,085
Balance at September 30, 2010	$ (168)	$ (168)
Balance at December 31, 2010	$ (469)	$ (469)
Unrealized gain	1,333	1,333
Balance at September 30, 2011	**$ 864**	**$ 864**

(G) *Environmental Matters.* There are a number of environmental matters that could have an effect on our financial condition or results of operations. At this time, the resolution of these matters is uncertain, and we have made no accruals for such contingencies and cannot reasonably estimate the possible loss or range of loss with respect to these 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. Beginning in 2011, we have become subject to climate change regulations that impose restrictions on emissions of greenhouse gases (including carbon dioxide), through the Prevention of Significant Deterioration preconstruction permitting program. As a result, we will have to evaluate any major modifications that we plan to undertake at our plants to determine whether they will need to undergo new source review permitting for greenhouse gases, and, if they do, whether any control technology will need to be added. We are also 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. New requirements 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. See "Item 2—Management's Discussion and Analysis of Financial Condition and Results of Operations—Financial Condition—Capital Requirements and Liquidity Sources of Capital—*Environmental Regulations*" in our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011 and "Item 1—BUSINESS—ENVIRONMENTAL AND OTHER REGULATION" in our 2010 Form 10-K for a more detailed discussion of current and potential future regulation. Failure to comply with these 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. Should we fail to be in compliance with these 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.

(H) *Restricted Short-term Investments.* At September 30, 2011, we had $105,823,000 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.

(I) *Regulatory Assets and Liabilities.* We apply the accounting guidance for regulated operations. Regulatory assets represent certain costs that are probable of recovery from our members in future revenues through rates under the wholesale power contracts with our members extending through December 31, 2050. Regulatory liabilities represent certain items of income that we are retaining and that will be applied in the future to reduce revenues required to be recovered from our members.

The following regulatory assets and liabilities are reflected on the accompanying condensed balance sheets as of September 30, 2011 and December 31, 2010.

	2011	2010
	(dollars in thousands)	
Regulatory Assets:		
Premium and loss on reacquired debt	**$101,661**	$111,570
Deferred amortization on capital leases	**51,001**	64,561
Deferred outage costs	**39,978**	23,796
Deferred interest rate swap termination fees	**22,313**	25,306
Asset retirement obligations	**43,939**	15,699
Deferred depreciation expense	**51,565**	52,632
Deferred investment impairment losses	**4,432**	5,214
Deferred charges related to Plant Vogtle Units 3 and 4 training costs	**15,441**	9,707
Other regulatory assets	**14,882**	2,651
Total Regulatory Assets	**$345,212**	$311,136
Regulatory Liabilities:		
Accumulated retirement costs for other obligations	**$ 36,834**	$ 39,205
Net benefit of Rocky Mountain transactions	**48,578**	50,965
Deferral of effects on net margin—Hawk Road and Murray Energy facilities	**24,123**	21,956
Major maintenance sinking fund	**29,283**	28,500
Deferred debt service adder	**35,113**	27,678
Other regulatory liabilities	**1,690**	1,931
Total Regulatory Liabilities	**$175,621**	$170,235
Net regulatory assets	**$169,591**	$140,901

The deferral of effects on net margins for the Murray and Hawk Road energy facilities presented in the table above represent the net of revenues and expenses associated with owning and operating the assets until our members require the power in 2016. The amounts will be deferred until 2016, at which time the amounts will be amortized over the remaining life of the plants. For information regarding the deferral of net margins for Murray, see Note L.

(J) *Member Power Bill Prepayments.* We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. At September 30, 2011, member power bill prepayments as reflected on the unaudited condensed balance sheet, including unpaid discounts, were $91,597,000, of which, $50,097,000 is classified as a current liability and $41,500,000 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 2012.

(K) *Debt.* In March 2011, the Development Authority of Appling County (Georgia), the Development Authority of Burke County (Georgia) and the Development Authority of Monroe County (Georgia) issued, on our behalf, $180,380,000 in aggregate principal amount of tax-exempt pollution control revenue bonds for the purpose of refunding certain pollution control revenue bonds previously issued by the development authorities on our behalf. The Series 2011 bonds are term rate bonds with a 2.5% interest rate which is fixed through February 28, 2013. $168,700,000 in proceeds of the 2011 bonds were used to refund a like amount of Series 2007 and 2008 pollution control revenue bonds that were subject to remarketing and interest rate reset on April 1, 2011. In conjunction with this refunding, we provided notice of optional redemption of the prior bonds in March 2011 and redeemed the bonds on April 1, 2011. The remaining proceeds of the 2011 bond issue were used to refund $11,680,000 of commercial paper that was used to refund a like amount of pollution control revenue bonds that matured on January 1, 2011.

On April 6, 2011, we closed a $260,000,000 three-year term loan with three banks to provide a portion of the interim financing for the Murray acquisition on April 8, 2011. The current interest rate on the loan is 1.50% and is based on one-month LIBOR. The term loan is set to mature in April 2014. For a discussion of the Murray acquisition, see Note L.

On August 19, 2011, we issued $300,000,000 of 5.25% First Mortgage Bonds, Series 2011 A primarily for the purpose of repaying outstanding commercial paper issued in connection with funding a portion of the cost of constructing Vogtle Units No. 3 and No. 4. The first mortgage bonds are secured under our first mortgage indenture.

As of September 30, 2011, we received advances on Rural Utilities Service-guaranteed/Federal Financing Bank loans totaling $353,619,000 to permanently finance the Hartwell and Hawk Road acquisitions and for general improvements at existing plants.

(L) *Plant Acquisition.* On April 8, 2011, we acquired 100% of KGen Murray I and II LLC, a wholly owned subsidiary of KGen Power Corporation. KGen Murray I and II LLC, subsequently renamed Murray I and II, LLC, owns the Murray Energy Facility, located near Dalton, Georgia. This facility consists of two natural gas-fired combined cycle units that have an aggregate summer planning reserve generation capacity of approximately 1,250 megawatts. As part of the acquisition, we assumed an existing power purchase and sale agreement with Georgia Power Company for the entire output of Murray Unit No. 1 through May 31, 2012. Our members currently plan to take the output of Murray on or before January 2016. Prior to our members' use of Murray, energy may be sold into the wholesale market.

We accounted for the transaction as a purchase business combination. In connection with the acquisition, which included acquisition related costs of approximately $1,962,000 (consisting primarily of legal and professional services which was recorded in the statement of revenues and expenses for the quarter ended June 30, 2011), we funded the entire $532,255,000 cash outlay by closing a $260,000,000 three-year term loan and by financing the remaining $272,255,000 through the issuance of commercial paper and draws under existing credit facilities.

The cash outlay of $532,255,000 includes a net working capital adjustment of $982,919 which was recorded in July 2011.

The following amounts represent the identifiable assets acquired and liabilities assumed in the Murray acquisition:

Recognized fair value amounts of identifiable assets acquired and liabilities assumed:	**(in millions)**
Property, plant and equipment	$456.7
Inventory	34.0
Other current assets	4.6
Power purchase and sale agreement	40.4
Emission credits	0.2
Current liabilities	(5.6)
Total identifiable net assets	**$530.3**

There was no goodwill associated with this acquisition.

We have consolidated the financial position and results of operations of Murray as of April 8, 2011. Our revenues for the three-month and nine-month periods ended September 30, 2011 include $82,573,000 and $134,494,000, respectively, related to capacity and energy sales from Murray. Prior to our members taking the output from Murray, the effect on net margins from Murray, including related interest costs, are being deferred as a regulatory asset or liability. The regulatory asset or liability will be amortized over the remaining life of the plant (estimated to be 30 years) beginning January 2016. For the three-month and nine-month periods ended September 30, 2011, we deferred $13,494,000 and $9,479,000, respectively, in excess revenues from Murray.

(M) *Sales to Non-Members.* For the three-month and nine-month periods ended September 30, 2011, we had $82,624,000 and $134,977,000, respectively, of sales to non-members consisting primarily of capacity and energy sales to Georgia Power under an agreement to sell the entire output of the recently acquired Murray Unit No. 1 through May 31, 2012. In addition, we sold energy generated at Murray Unit No. 2 to non-members.

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 2010 Form 10-K. 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 Nine Months Ended September 30, 2011 and 2010

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 expansion, our board approved budgets for 2010 and 2011 to achieve a 1.14 margins for interest ratio. As our generation expansion program evolves, our board 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 nine-month periods ended September 30, 2011 was $10.4 million and $39.2 million compared to $13.8 million and $35.9 million for the same periods of 2010. Through September 30, 2011, we collected 103.7% of our targeted net margin of $37.8 million for the year ending December 31, 2011. This is typical as our management generally budgets conservatively and makes adjustments to the budget throughout the year so that net margins 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 5.6% and 5.3% in the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. Megawatt-hour sales to members decreased 8.6% and 11.7% for the three-month and nine-month periods ended September 30, 2011 versus the same periods of 2010. The average total revenue per megawatt-hour from sales to members increased 3.4% and 7.3% for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010.

The components of member revenues for the three-month and nine-month periods ended September 30, 2011 and 2010 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	**2011**	2010
Capacity revenues	**$ 171,582**	$ 172,217	**$ 515,061**	$ 514,435
Energy revenues	**178,324**	198,385	**432,069**	485,958
Total	**$ 349,906**	$ 370,602	**$ 947,130**	$ 1,000,393
Kilowatt-hours sold to members	**6,077,054**	6,649,453	**15,401,272**	17,451,164
Cents per kilowatt-hour	**5.76¢**	5.57¢	**6.15¢**	5.73¢

Energy revenues were 10.1% and 11.1% lower for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. Our average energy revenue per megawatt-hour from sales to members were 1.6% lower and 0.7% higher for the three-month and nine-month periods ended September 30, 2011 as compared to the same periods of 2010. The decrease in energy revenues resulted primarily from lower megawatt-hour sales to our members primarily as a result of a planned outage at Plant Scherer and an unplanned outage at Chattahoochee which resulted in lower generation from these plants in 2011 compared to 2010. For a discussion of fuel costs and total generation, see "*—Operating Expenses.*"

Sales to Non-Members. Sales to non-members for the three-month and nine-month periods ended September 30, 2011 consisted primarily of capacity and energy sales to Georgia Power Company under an agreement to sell the entire output of the recently acquired Murray Unit No. 1 through May 31, 2012. In addition, we sold energy generated at Murray Unit No. 2 to non-members. See Note L of Notes to Unaudited Condensed Financial Statements for further discussion of our acquisition of Murray.

Operating Expenses

Operating expenses for the three-month and nine-month periods ended September 30, 2011 increased 19.6% and 9.3% compared to the same periods of 2010. The increase in operating expenses was primarily due to higher fuel, production and depreciation and amortization costs offset somewhat by lower purchased power costs.

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

	Three Months Ended September 30,			
	2011		2010	
Fuel Source	**Cost**	**Generation**	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal	**$ 73,377**	**2,488,052**	$ 81,437	2,835,756
Nuclear	**19,869**	**2,486,884**	18,092	2,669,806
Gas	**94,599**	**2,332,508**	60,158	1,305,749
Pumped Storage	**1,138**	**346,849**	487	346,313
	$188,983	**7,654,293**	$160,174	7,157,624
	Cost	**Purchased**	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power	**$ 20,925**	**196,147**	$ 24,721	64,711

	Nine Months Ended September 30,			
	2011		2010	
Fuel Source	**Cost**	**Generation**	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal	**$196,283**	**6,485,543**	$226,518	8,117,061
Nuclear	**54,385**	**7,192,838**	47,901	7,358,843
Gas	**169,727**	**4,088,376**	107,977	2,271,983
Pumped Storage	**2,394**	**776,713**	1,354	767,306
	$422,789	**18,543,470**	$383,750	18,515,193
	Cost	**Purchased**	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power	**$ 46,080**	**256,825**	$ 60,346	291,339

For the three-month and nine-month periods ended September 30, 2011, total fuel costs increased 18.0% and 10.2% and total megawatt-hour generation increased 6.9% and 0.2% compared to the same periods of 2010. Average fuel costs per megawatt-hour increased 10.3% and 10.0% in the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. The increase in total fuel costs and generation resulted primarily from increased natural gas-fired generation of 1,027,000 megawatt-hours and 1,816,000 megawatt-hours for the three-months and nine-months ended September 30, 2011 compared to the same periods of 2010 primarily due to generation from Murray which was sold to non-members. This increase was offset somewhat by a decrease in generation for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010 of 348,000 megawatt-hours and 1,632,000 megawatt-hours in coal-fired generation primarily due to a scheduled outage at Plant Scherer for the installation of environmental compliance equipment and general maintenance in 2011. The average fuel cost per megawatt-hour of gas-fired generation is substantially higher than nuclear generation and is also higher than coal generation; thus, the increase in gas-fired generation was the primary contributor to the increase in average fuel costs per megawatt-hour of generation.

Total production costs increased 8.9% and 9.4% for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. The increase in production costs for the quarter ended September 30, 2011 compared to the same period of 2010 was partly due to operation and maintenance expenses incurred at Murray and partly due to costs incurred to repair a damaged transformer at the Hawk Road Energy Facility. For the nine-month period ended September 30, 2011 compared to the same period of 2010 the increase resulted from, in addition to Murray, a planned major maintenance outage at Hawk Road and increased general operations and maintenance expenses at Plants Vogtle, Hatch, Scherer and Wansley. The increase for the nine months ended September 30, 2011 as compared to the same period of 2010 was offset somewhat by lower operations and maintenance costs at the Hartwell Energy Facility; 2010 operations and maintenance costs for Hartwell included major maintenance outage costs.

Depreciation and amortization costs increased 59.7% and 35.5% for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. This increase resulted primarily from depreciation of Murray, in addition to higher depreciation for Plants Scherer and Wansley related to environmental compliance projects recently placed in service.

Total purchased power costs decreased 15.4% and 23.6% for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. Purchased megawatt-hours increased 203.1% and decreased 11.8% for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. The increase in purchased megawatt-hours for the third quarter of 2011 as compared to the same quarter of 2010 resulted from an increase in megawatt-hours acquired under our energy replacement program, which replaces power from our owned generation facilities with energy purchased at lower prices in the spot market. Megawatt-hours acquired under our energy replacement program were lower for the nine-months ended September 30, 2011 as compared to the same period of 2010. The decrease in purchased power costs for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010 was primarily due to lower 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 Murray and Hawk Road 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 Murray elect to take energy from Murray prior to 2016, the deferral of the effect on net margin would terminate for that member and the amortization of that members' deferral would commence immediately. The changes in cost deferrals in 2011 compared to 2010 resulted from the Murray and Hawk Road costs discussed above in production costs. For further discussion regarding the deferral plan, see "—Capital Requirements and Liquidity—*Future Power Resources—Rate Matters.*"

Other Income

The decrease in the other income for the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010 is primarily due to the amortization of project costs associated with the construction of a combined cycle plant that was canceled due to the Murray acquisition in April 2011.

Interest charges

Interest expense increased by 14.8% and 10.9% in the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010. This increase is primarily due to the increased debt issued for the purpose of financing the construction of Vogtle Units No. 3 and No. 4.

Allowance for debt funds used during construction increased by 70.3% and 77.6% in the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010 primarily due to construction expenditures for Vogtle Units No. 3 and No. 4.

Amortization of debt discount and expense decreased 6.4% and 10.5% in the three-month and nine-month periods ended September 30, 2011 compared to the same periods of 2010 primarily due to the completed amortization (in December 2010) of issuance costs associated with transactions in 2009 to provide supplemental credit enhancement for the Rocky Mountain lease arrangements.

Financial Condition

Balance Sheet Analysis as of September 30, 2011

Assets

Cash used for property additions for the nine-month period ended September 30, 2011 totaled $635.0 million. Of this amount, $352.1 million was associated with construction expenditures for Vogtle Units No. 3 and No. 4. The remaining expenditures were primarily for environmental control systems being installed at Plant Scherer, normal additions and replacements to existing generation facilities and purchases of nuclear fuel.

Cash and cash equivalents decreased by $261.8 million in the nine-month period ended September 30, 2011. The decrease can be attributed primarily to capital expenditures of $635.0 million for property additions and principal and interest payments of $474.5 million, which were partially offset by long-term debt proceeds. In addition, we financed the $530.3 million Murray acquisition through the issuance of commercial paper and a three-year term loan. For information regarding financing of the Murray acquisition, see "—Capital Requirements and Liquidity and Sources of Capital—*Financing Activities.*"

The $105.8 million of restricted short-term investments at September 30, 2011 represented funds deposited into a Rural Utilities Service Cushion of Credit Account with the U.S. Treasury that 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. For information regarding the Rural Utilities Service Cushion of Credit Account, see Note H of Notes to Unaudited Condensed Financial Statements and "—Capital Requirements and Liquidity and Sources of Capital—*Liquidity.*"

Receivables increased by $34.5 million in the nine-month period ended September 30, 2011. The December 31, 2010 receivables balance included approximately $10.3 million of credits available to the members for a board approved reduction to 2010 revenue requirements as a result of margins collected in excess of our 2010 target. A portion of the increase in receivables was due to these credits being utilized by the members during the first half of 2011. In addition, $17.4 million of the increase was related to non-member energy sales. For information regarding non-member energy sales, see Note M of Notes to Unaudited Condensed Financial Statements.

Inventories, at average cost, increased $32.0 million in the nine-month period ended September 30, 2011 due to inventory acquired in connection with the Murray acquisition.

Other deferred charges increased $27.0 million in the nine-month period ended September 30, 2011 primarily due to the $19.1 million amortized value of the intangible asset recorded for the Georgia Power purchase and sale agreement assumed as part of the Murray acquisition. In addition, $5.3 million of the increase was attributed to Georgia Power related deferred equipment prepayments that will be expensed or capitalized once utilized.

Equity and Liabilities

Long-term debt increased $862.5 million for the nine-month period ended September 30, 2011. The increase was due in part to a $260.0 million three-year term loan which closed in April 2011 to provide interim financing for the Murray acquisition and $353.6 million in advances on Rural Utilities Service-guaranteed Federal Financing Bank loans to permanently finance the Hartwell and Hawk Road acquisitions and other general improvements. In August 2011, we issued $300.0 million in first mortgage bonds for the purpose of repaying outstanding commercial paper issued in connection with funding a portion of constructing Vogtle Units No. 3 and No. 4. The first mortgage bonds are secured under our first mortgage indenture.

Long-term debt and capital leases due within one year decreased $34.0 million primarily as a result of scheduled debt maturities and the reclassification of certain long-term debt.

Short-term borrowings for the nine-month period ended September 30, 2011 decreased $30.2 million. The decrease was primarily due to the repayment of commercial paper issued to fund capital expenditures related to Vogtle Units No. 3 and No. 4 and to provide interim financing of the 2009 Hartwell and Hawk Road acquisitions.

Accounts payable decreased $19.8 million in the nine-month period ended September 30, 2011 primarily due to a $35.2 million decrease in the payable to Georgia Power for operation and maintenance costs for our co-owned plants and capital costs primarily associated with Vogtle Units No. 3 and No. 4 construction. Offsetting the decrease was a $13.0 million increase in the payable for natural gas, primarily due to an increase in natural gas-fired generation at Murray and the Chattahoochee Energy Facility. At December 31, 2010, Chattahoochee was in an unplanned outage and did not resume operation until April 2011.

The $30.5 million decrease in accrued interest for the nine-month period ended September 30, 2011 was due to the normal timing differences between interest payments and interest expense accruals.

Accrued and withheld taxes decreased $4.9 million for the nine-month period ended September 30, 2011 as a result of payments made, when due, for 2010 property taxes, which exceeded normal 2011 property tax accruals.

Member power bill prepayments represent funds received from the members for prepayment of their monthly power bills. At September 30, 2011, $50.1 million of member power bill prepayments was classified as a current liability and $41.5 million of member power bill prepayments was classified as a long-term liability. During the nine-month period ended September 30, 2011, approximately $49.3 million of prepayments were received from the members and approximately $70.2 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note J 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

Future Power Resources

To meet the energy needs of our members, we are in a period of generation expansion. In addition to acquiring more than 2,000 megawatts of capacity through the purchases of the Hawk Road, Hartwell and Murray energy facilities, members have subscribed to a 30% interest in Vogtle Units No. 3 and No. 4 (660 megawatts), which are currently under construction. We continue to evaluate additional generation resource development opportunities to help meet our members' projected power supply needs over the next ten years. For further discussion of our planned future generation resources and projected capital expenditures, see "Item 1—BUSINESS—Our Power Supply Resources—*Future Power Resources*" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND

RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2010 Form 10-K.

Vogtle Units No. 3 and No. 4. On September 27 and 28, 2011, the Nuclear Regulatory Commission held the mandatory hearing for the combined construction permits and operating licenses for Vogtle Units No. 3 and No. 4 and for Georgia Power's request for a second limited work authorization. On October 18, 2011, the Atomic Safety and Licensing Board denied the remaining motions seeking to re-open the Vogtle Units No. 3 and No. 4 licensing proceeding; however, on October 27, 2011, the petitioners requested reconsideration of this decision and, on November 2, 2011, further appealed to the Nuclear Regulatory Commission to admit their contentions, should they again be denied by the Atomic Safety and Licensing Board. The remaining steps in the regulatory process are to address the status of these petitions and obtain Nuclear Regulatory Commission approvals of the AP1000 Design Certification Amendment and the combined construction permits and operating licenses which Georgia Power expects in late 2011. However, due to certain administrative procedural requirements, it is possible that the effective date of the design certification amendment and issuance of the combined construction permits and operating licenses could occur in early 2012. In this case, the Nuclear Regulatory Commission could approve the second limited work authorization, which would allow Georgia Power to perform additional construction activities related to the nuclear island in late 2011 and obtain commercial operation in 2016 and 2017 for Vogtle Units No. 3 and No. 4, respectively.

During the course of construction, issues have materialized that may impact the budget and schedule for Vogtle Units No. 3 and No. 4, including potential costs associated with compressing the current project schedule to avoid delays in the respective commercial operation dates of the units. This potential schedule compression relates to making up time due to a delay in obtaining regulatory approval for the design certification document. We, along with Georgia Power, the Municipal Electric Authority of Georgia and the City of Dalton, the "Co-Owners," and Westinghouse and Stone & Webster, Inc., the "Consortium," have agreed to informal and formal processes with respect to submitting and negotiating any such issues. If the parties are unable to resolve any disputes through informal negotiations, the disputes, including the potential schedule compression, will be resolved through the formal dispute resolution procedures agreed to by the parties. The Co-Owners have successfully used both the informal and formal procedures to resolve disputes and expect to resolve any existing and future disputes through these procedures as well.

There are other pending technical and procedural challenges to the construction and licensing of Vogtle Units No. 3 and No. 4, including petitions filed at the Nuclear Regulatory Commission in response to the events in Japan. 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.

As of September 30, 2011, our total capitalized costs to date for Vogtle Units No. 3 and No. 4 were $1.2 billion.

Events in Japan. In March 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. Both Georgia Power, on behalf of the Co-Owners, and we continue to monitor the response to this event and have not identified any immediate impact to the licensing and construction of Vogtle Units No. 3 and No. 4 or the operation of our existing nuclear facilities.

The Nuclear Regulatory Commission is performing additional operational and safety reviews of nuclear facilities in the United States, which could potentially impact future operations and capital requirements. In July 2011, a special Nuclear Regulatory Commission task force issued a report with initial recommendations for enhancing nuclear reactor safety in the United States, including potential changes in emergency planning, onsite backup generation and spent fuel pools for existing reactors. However, the final form and resulting impact of any changes to safety requirements for existing nuclear reactors will be dependent on further review and action by the Commission and cannot be determined at this time. The task force report supported completion of the certification of the AP1000 reactor design being used at Vogtle Units No. 3 and No. 4, noting that the design includes many of the features necessary to address the task force's recommendations.

The ultimate outcome of these matters, including petitions filed with the Nuclear Regulatory Commission in response to the events in Japan, cannot be determined at this time. See "Item 1A—RISK FACTORS" in our 2010 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.

Rate Matters. Our board of directors has approved two rate management programs, which we developed based on requests from members that have subscribed to the Plant Vogtle units under construction and Murray. The first program allows members to expense rather than capitalize interest during construction on the Plant Vogtle units and the second program allows members to expense rather than defer the net costs associated with Murray. See Note L of Notes to Unaudited Condensed Financial Statements for a discussion of the deferral associated with Murray. Each subscribing member may elect to participate in one or both of these programs. The Plant Vogtle rate management program will be available starting in 2012 and allows each subscribing member to make an annual election to expense a percentage of its allocated portion of interest during construction for the year, although only current year costs may be expensed. The Murray rate management program will be available starting on December 31, 2011 and allows each subscribing member to make an annual election to expense a percentage of its allocated portion of Murray's monthly net costs for that year that would otherwise be deferred, and to elect once a year to expense any previously deferred net costs. The rate schedule changes required to implement these programs are subject to approval by the Rural Utilities Service. Any effect of these rate management programs on our financial statements is subject to member elections to participate.

Environmental Regulations

The Environmental Protection Agency continues to develop a number of rules that would significantly expand the scope of regulation of air emissions, water intake and waste management at power plants. See "Item 1A—RISK FACTORS" in our 2010 Form 10-K for further discussion regarding potential effects on our business from environmental regulation.

On August 8, 2011, EPA finalized the Cross-State Air Pollution Rule, which contains new sulfur dioxide and nitrogen oxides emission reduction requirements for existing electric generating units in most of the eastern United States, including Georgia. For 2012, compliance with the rule may necessitate some combination of the purchase of emission allowances and/or the limiting of operations at Plant Scherer during off-peak periods. Such steps should become unnecessary in 2013 and beyond, due to additional emission control equipment scheduled for installation and operation at Plant Scherer starting in that year. EPA proposed certain technical amendments to the rule in October 2011, including a postponement of the assurance penalty provisions until 2014 from 2012, which may allow for increased interstate trading of allowances in the first two years, 2012 and 2013, of the program. Various challenges to the rule have been filed with EPA and the U.S. Court of Appeals for the District of Columbia Circuit, in some cases accompanied by a request for a stay of the rule, raising doubt as to whether the program will begin as currently scheduled on January 1, 2012. Although the ultimate outcome of the rule will depend on further rulemaking or the results of such challenges, the Cross-State Air Pollution Rule is not expected to have a significant impact on the operation of our plants or financial condition.

EPA has also proposed stringent new maximum achievable control technology (MACT) emission limits for certain hazardous air pollutants, including mercury, from coal- and oil-fired electric generating units (EGUs) in the EGU MACT rule. Recently, all parties to the relevant consent decree and the court agreed to extend the deadline by which EPA must issue a final EGU MACT rule by 30 days, from November 16, 2011 to December 16, 2011. The total cost of compliance will depend on the final rule and the outcome of any legal challenges cannot be determined with certainty at this time.

After its 2010 proposal of two alternative approaches for regulating coal combustion byproducts from electric utilities, regulation as either (i) "special wastes" under hazardous waste rules or (ii) as solid wastes, EPA continues to consider the numerous comments received from interested stakeholders and other members of the public. In October, EPA asked for further comments on certain data submitted during the original comment period. The ultimate impacts associated with EPA's coal combustion proposal cannot be determined with certainty at this time, and will depend on future rulemakings and possible Congressional action.

We cannot predict at this time the ultimate effects these proposed and final regulations may have on the operations and costs of our existing or future power plants, including capital costs. We, along with the other owners of our co-owned facilities, continue to review the potential effects of recent environmental regulations. For further discussion regarding environmental regulations and potential capital requirements, see "Item 2—Management's Discussion and Analysis of Financial Condition and Results of Operations—Financial Condition—Capital Requirements and Liquidity Sources of Capital—*Environmental Regulations*" in our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2011 and "Item 1—BUSINESS—ENVIRONMENTAL AND OTHER REGULATION" and "Item 7—MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Capital Requirements—Capital Expenditures*" in our 2010 Form 10-K.

Liquidity

At September 30, 2011, we had $1.8 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $410 million in cash and cash equivalents and $1.4 billion of unused and available committed credit arrangements.

On September 30, 2011, we completed the last component of our planned liquidity restructuring for 2011 by closing on a new $110 million, five-year unsecured line of credit facility with National Rural Utilities Cooperative Finance Corporation. As a result, at September 30, 2011 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. We believe this amount of liquidity will be sufficient to cover our interim funding needs through the period of generation expansion and to provide a reasonable cushion for our normal business operations.

Committed Credit Facilities

	Authorized Amount	Available 9/30/2011	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit[1]	$1,265	$ 856[2]	June 2015
CFC Line of Credit	110	110	September 2016
JPMorgan Chase Line of Credit	150	33[3]	December 2013
Secured facilities:			
CoBank Line of Credit	150	150	November 2012
CFC Line of Credit	250	250	December 2013
Total	**$1,925**	**$1,399**	

(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, $274 million is dedicated to support commercial paper we have issued and $135 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, $114 million relates to letters of credit issued under this facility to support variable rate demand bonds and $3 million relates to letters of credit issued to post collateral to third parties.

Due to the significant expenditures we are incurring relating to environmental compliance projects and acquiring and constructing 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 the environmental compliance expenditures, for a portion of the cost to acquire Murray and for construction of Vogtle Units No. 3 and No. 4 until permanent financing for these projects is put in place.

Under the commercial paper program, we can issue commercial paper in amounts that do not exceed the amount of any committed lines of credit we have in place, thereby providing 100% dedicated backup support for any paper outstanding. We periodically assess our needs in order to determine the appropriate amount of commercial paper backup to maintain. In connection with the increase in the size of our main revolving credit facility to $1.265 billion, we also increased the size of our commercial paper program to that level.

Like the lines of credit from CFC, JPMorgan Chase Bank and CoBank, funds may be advanced under the syndicated line of credit for general working capital purposes. In addition, under some of our committed credit facilities we have the ability to issue letters of credit totaling $910 million in the aggregate, of which $658 million remained available at September 30, 2011. 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.

Under the $250 million line of credit with CFC, we have the option of converting any amounts outstanding under the line of credit to a term loan with a maturity no later than December 31, 2043. Any amounts drawn under the $250 million CFC line of credit, as well as any amounts converted to a term loan, will be secured under our first mortgage indenture.

Several of our line of credit facilities contain a financial covenant that requires us to maintain minimum levels of patronage capital. At September 30, 2011, the required minimum level was $575 million and our actual patronage capital was $635 million. Additional covenants contained in several of our credit facilities limit the amount of secured indebtedness and unsecured indebtedness we can have outstanding. At September 30, 2011, the most restrictive of these covenants limits our secured indebtedness to $9.5 billion and our unsecured indebtedness to $4.0 billion. At September 30, 2011, we had $5.6 billion of secured indebtedness and $627 million 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 September 30, 2011, the balance of member prepayments received but not yet credited to their power bills was $91.6 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 2012. For more information regarding the power bill prepayment program, see Note J of Notes to Unaudited Condensed Financial Statements.

At September 30, 2011, current assets included $105.8 million of restricted short-term investments pursuant to deposits made to a Rural Utilities Service Cushion of Credit Account. The deposits with the U.S. Treasury were made voluntarily and earn interest at a guaranteed rate of 5% per annum. The funds in the account, including interest thereon, can only be applied to debt service payments on Rural Utilities Service notes and Rural Utilities Service-guaranteed Federal Financing Bank notes. Our decisions regarding how to apply the funds are guided by the interest rate environment and our anticipated liquidity needs.

Financing Activities

First Mortgage Indenture. At September 30, 2011, we had $5.4 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 2010 Form 10-K for a further discussion of our first mortgage indenture.

Bond Financing. As disclosed in a Current Report on Form 8-K filed on August 17, 2011, in August we issued $300 million of taxable first mortgage bonds primarily for the purpose of repaying outstanding commercial paper issued in connection with funding a portion of the cost of constructing Vogtle Units No. 3 and No. 4. The first mortgage bonds are secured under our first mortgage indenture.

Rural Utilities Service-Guaranteed Loans. We have six approved Rural Utilities Service-guaranteed loans, being funded through the Federal Financing Bank, totaling $1.67 billion that are in the process of being drawn down, with $1.1 billion remaining to be advanced. The debt will be secured under our first mortgage indenture.

Department of Energy-Guaranteed Loans. We have 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 approximately 70% of the estimated $4.2 billion cost to construct our 30% undivided interest in Vogtle Units No. 3 and No. 4, not to exceed $3.057 billion. This loan would be funded by the Federal Financing Bank, guaranteed by the Department of Energy and secured under our first mortgage indenture.

We are working with the Department of Energy to finalize the loan guarantee, including the negotiation of definitive loan agreements. However, final approval and issuance of a loan guarantee by the Department of Energy is subject to receipt of the combined construction permits and operating licenses for Vogtle Units No. 3 and No. 4 from the Nuclear Regulatory Commission, completion of due diligence by the Department of Energy 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 Vogtle Units No. 3 and No. 4 costs not funded under the Department of Energy loan guarantee program would be financed through the issuance of taxable bonds.

Of the approximately $1.2 billion of currently estimated project costs not expected to be funded under the Department of Energy loan guarantee program, we have already financed $1.15 billion through the issuance of first mortgage 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*" in our 2010 Form 10-K. For a discussion of our activities to mitigate the risk of rising interest rates associated with this financing, see "Quantitative and Qualitative Disclosures About Market Risk."

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

We are exposed to the risk of rising interest rates due to the significant amount of new long-term debt we will 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 the new Vogtle units. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Financial Condition—Capital Requirements and Liquidity and Sources of Capital—*Financing Activities—Department of Energy-Guaranteed Loans*." 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. To mitigate the risk of rising interest rates, we initiated a hedging program in October 2011, which we expect to complete in November 2011. Under this program, we expect to make upfront premium payments of up to $100 million to purchase interest rate options to hedge the interest rates on approximately $2.2 billion of the Department of Energy-guaranteed loan, representing a substantial portion of the expected borrowings from 2013 through 2017. Expected borrowings in 2012 will not be hedged. As of November 14, 2011, we have hedged interest rates on $1.4 billion of expected borrowings.

The interest rate options we are purchasing, commonly known as LIBOR swaptions, are designed to cap our effective interest rate by providing us a lump-sum cash payment on the expiration date of the swaption based on its value on that date. This value depends on the extent to which prevailing LIBOR swap rates exceed the option rate, and the value would be zero if swap rates are at or below the option rate. The swaptions' expiration dates are timed to match the expected quarterly draw dates of the

Department of Energy-guaranteed loan advances to be hedged; however, as the swaptions' value is independent from the Department of Energy-guaranteed loan, the swaptions could also serve as a hedge of interest rates on an alternative source of financing.

We pay the entire premium at the time we enter into these swaption transactions and have no additional payment obligations. However, upon expiration of the swaptions, each counterparty will be obligated to pay us the cash value of the swaption, if any. In order to diversify counterparty risk, we plan to enter into these transactions with up to seven large banks with average ratings ranging from A+ to AA. 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 swaptions outstanding for that counterparty exceeds a certain threshold. The collateral thresholds range from $0 to $10 million depending on each counterparty's credit rating.

We expect to defer any gains or losses from the change in fair value of each swaption and related carrying and other incidental costs. The deferred costs, which are not expected to exceed $135 million, and deferred gains, if any, from the sale or settlement of the swaptions will then be amortized and collected in rates over the life of the expected Department of Energy-guaranteed loan.

Item 4. Controls and Procedures

As of September 30, 2011, 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 or results of operations.

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 2010 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. Reserved

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: November 14, 2011

By: /s/ Thomas A. Smith

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

Date: November 14, 2011

/s/ Elizabeth B. Higgins

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