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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 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 JUNE 30, 2011

PART I—FINANCIAL INFORMATION
Item 1. Financial Statements

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

	(dollars in thousands)	
	2011	2010
	(Unaudited)	
Assets		
Electric plant:		
In service	**$ 7,294,325**	$ 6,672,253
Less: Accumulated provision for depreciation	**(3,265,632)**	(3,101,731)
	4,028,693	3,570,522
Nuclear fuel, at amortized cost	**273,254**	249,563
Construction work in progress	**1,497,072**	1,195,475
	5,799,019	5,015,560
Investments and funds:		
Decommissioning fund	**278,235**	265,483
Deposit on Rocky Mountain transactions	**127,740**	123,573
Investment in associated companies	**57,019**	56,125
Long-term investments	**81,342**	79,212
Other, at cost	**3,508**	3,570
	547,844	527,963
Current assets:		
Cash and cash equivalents, at cost	**417,946**	672,212
Restricted cash, at cost	**3,770**	6,300
Restricted short-term investments	**15,626**	97,286
Receivables	**165,204**	106,674
Inventories, at average cost	**204,850**	171,815
Prepayments and other current assets	**13,631**	13,416
	821,027	1,067,703
Deferred charges:		
Deferred debt expense, being amortized	**62,492**	59,202
Regulatory assets	**312,860**	311,136
Other	**49,228**	15,498
	424,580	385,836
	$ 7,592,470	$ 6,997,062

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

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

	(dollars in thousands)	
	2011 (Unaudited)	2010
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 624,780**	$ 595,952
Accumulated other comprehensive margin (deficit)	**123**	(469)
	624,903	595,483
Long-term debt	**5,244,443**	4,657,127
Obligation under capital leases	**161,661**	179,288
Obligation under Rocky Mountain transactions	**127,740**	123,573
	6,158,747	5,555,471
Current liabilities:		
Long-term debt and capital leases due within one year	**134,309**	170,947
Short-term borrowings	**353,653**	305,959
Accounts payable	**189,949**	139,614
Accrued interest	**53,638**	76,435
Accrued and withheld taxes	**19,602**	27,171
Member power bill prepayments, current	**40,620**	71,496
Other current liabilities	**19,409**	18,567
	811,180	810,189
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**27,350**	28,587
Asset retirement obligations	**289,736**	280,496
Member power bill prepayments, non-current	**29,920**	41,000
Power sale agreement, being amortized	**62,148**	69,480
Regulatory liabilities	**165,237**	170,235
Other	**48,152**	41,604
	622,543	631,402
	$7,592,470	$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 Six Months Ended June 30, 2011 and 2010

	(dollars in thousands)			
	Three Months		Six Months	
	2011	2010	**2011**	2010
Operating revenues:				
Sales to Members	**$327,776**	$325,963	**$597,224**	$629,791
Sales to non-Members	**52,027**	147	**52,353**	392
Total operating revenues	**379,803**	326,110	**649,577**	630,183
Operating expenses:				
Fuel	**161,355**	121,459	**233,804**	223,551
Production	**89,866**	85,878	**179,055**	163,261
Depreciation and amortization	**49,468**	33,605	**83,873**	67,444
Purchased power	**13,600**	18,217	**25,155**	35,625
Accretion	**4,565**	4,282	**9,125**	8,566
Deferral of effect on net margin for Hawk Road and Murray Energy facilities	**(2,753)**	2,900	**(11,072)**	6,071
Total operating expenses	**316,101**	266,341	**519,940**	504,518
Operating margin	**63,702**	59,769	**129,637**	125,665
Other income:				
Investment income	**6,926**	7,497	**14,320**	15,153
Other	**1,957**	2,901	**5,323**	6,182
Total other income	**8,883**	10,398	**19,643**	21,335
Interest charges:				
Interest expense	**72,279**	65,555	**142,945**	131,143
Allowance for debt funds used during construction	**(17,753)**	(8,676)	**(32,981)**	(18,137)
Amortization of debt discount and expense	**5,341**	5,888	**10,488**	11,990
Net interest charges	**59,867**	62,767	**120,452**	124,996
Net margin	**$ 12,718**	$ 7,400	**$ 28,828**	$ 22,004

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

Oglethorpe Power Corporation
Condensed Statements of Patronage Capital and Membership Fees
and Accumulated Other Comprehensive Margin (Deficit) (Unaudited)
For the Six Months Ended June 30, 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	22,004	—	22,004
Unrealized gain on available-for-sale securities	—	1,033	1,033
Total comprehensive margin			23,037
Balance at June 30, 2010	$584,223	$ (220)	$584,003
Balance at December 31, 2010	$595,952	$ (469)	$595,483
Components of comprehensive margin:			
Net margin	28,828	—	28,828
Unrealized gain on available-for-sale securities	—	592	592
Total comprehensive margin			29,420
Balance at June 30, 2011	**$624,780**	**$ 123**	**$624,903**

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

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

	(dollars in thousands)	
	2011	2010
Cash flows from operating activities:		
Net margin	**$ 28,828**	$ 22,004
Adjustments to reconcile net margin to net cash provided by (used in) operating activities:		
Depreciation and amortization, including nuclear fuel	**144,131**	123,717
Accretion cost	**9,125**	8,566
Amortization of deferred gains	**(2,830)**	(2,830)
Allowance for equity funds used during construction	**(1,404)**	(994)
Deferred outage costs	**(36,672)**	(25,080)
Deferral of effect on net margin for Hawk Road and Murray Energy Facilities	**(11,072)**	6,071
Gain on sale of investments	**(10,324)**	(9,015)
Regulatory deferral of costs associated with nuclear decommissioning	**5,553**	4,422
Other	**(3,622)**	(2,438)
Change in operating assets and liabilities:		
Receivables	**(54,078)**	(44,018)
Inventories	**1,171**	15,153
Prepayments and other current assets	**(215)**	(1,946)
Accounts payable	**19,553**	5,935
Accrued interest	**(22,796)**	(1,358)
Accrued and withheld taxes	**(7,920)**	(9,982)
Member power bill prepayments	**(41,957)**	(90,357)
Other current liabilities	**1,376**	(5,197)
Total adjustments	**(11,981)**	(29,351)
Net cash provided by (used in) operating activities	**16,847**	(7,347)
Cash flows from investing activities:		
Property additions	**(397,229)**	(335,145)
Plant acquisition	**(529,310)**	—
Activity in decommissioning fund—Purchases	**(557,748)**	(299,446)
—Proceeds	**554,710**	296,933
Decrease in restricted cash and cash equivalents	**2,530**	14,383
Decrease (increase) in restricted short-term investments	**81,660**	(42,282)
Activity in investment in associated organizations—Purchases	**(4,371)**	(4,012)
—Proceeds	**3,768**	2,505
Activity in other long-term investments—Purchases	**(824)**	(2,367)
—Proceeds	**700**	2,700
Other	**(3,955)**	6,349
Net cash used in investing activities	**(850,069)**	(360,382)
Cash flows from financing activities:		
Long-term debt proceeds	**793,999**	222,631
Long-term debt payments	**(260,981)**	(200,197)
Increase in short-term borrowings, net	**47,694**	127,245
Other	**(1,756)**	1,930
Net cash provided by financing activities	**578,956**	151,609
Net decrease in cash and cash equivalents	**(254,266)**	(216,120)
Cash and cash equivalents at beginning of period	**672,212**	579,069
Cash and cash equivalents at end of period	**$ 417,946**	$ 362,949
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 126,758**	$ 108,629
Supplemental disclosure of non-cash investing and financing activities:		
Change in plant expenditures included in accounts payable	**$ 30,335**	$ 73,221

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

Oglethorpe Power Corporation
Notes to Unaudited Condensed Financial Statements
For the Three and Six Months ended June 30, 2011 and 2010

(A) *General.* The condensed financial statements included in this report have been prepared by us pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the information furnished in this report reflects all adjustments (which include only normal recurring adjustments) and estimates necessary to fairly state, in all material respects, the results for the three- and six-month periods ended June 30, 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 six-month periods ended June 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 June 30, 2011 and December 31, 2010.

		Fair Value Measurements at Reporting Date Using		
	June 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	**$109,215**	$109,215	$ —	$ —
International equity	**49,300**	49,300	—	—
Corporate bonds	**43,139**	43,139	—	—
US Treasury and government agency securities	**31,983**	31,983	—	—
Agency mortgage and asset backed securities	**36,178**	36,178	—	—
Derivative instruments	**(505)**	—	—	(505)
Other	**8,925**	8,925	—	—
Bond, reserve and construction funds	**2,753**	2,753	—	—
Long-term investments	**81,342**	73,294	—	8,048[1]
Natural gas swaps	**(2,152)**	—	(2,152)	—

		Fair Value Measurements at Reporting Date Using		
	December 31, 2010	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 six months ended June 30, 2011 and 2010.

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

	Three Months Ended June 30, 2010	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at March 31, 2010	$(435)	$26,376
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	124	—
Impairment included in other comprehensive deficit	—	109
Liquidations	—	(2,000)
Balance at June 30, 2010	$(311)	$24,485

	Six Months Ended June 30, 2011	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at January 1, 2011	$(452)	$ 8,671
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(53)	77
Impairment included in other comprehensive deficit	—	—
Liquidations	—	(700)
Balance at June 30, 2011	**$(505)**	**$ 8,048**

	Six Months Ended June 30, 2010	
	Decommissioning funds	Long-term investments
	(dollars in thousands)	
Assets (Liabilities):		
Balance at January 1, 2010	$(260)	$27,010
Total gains or losses (realized/unrealized):		
Included in earnings (or changes in net assets)	(51)	—
Impairment included in other comprehensive deficit	—	175
Liquidations	—	(2,700)
Balance at June 30, 2010	$(311)	$24,485

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 rates, which was adjusted for illiquidity premiums based on discussions with market participants. At June 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 June 30, 2011, we recorded a ($77,000) 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 June 30, 2011, would have resulted in an additional decrease in the fair value of our auction rate securities investments by approximately $540,000.

As of June 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 June 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 June 30, 2011, the estimated fair value of our natural gas contracts was an unrealized loss of approximately $2,152,000. 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 June 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 June 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 June 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 $2,152,000 with our counterparties.

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

Year	**Natural Gas Swaps (MMBTUs)** (in millions)
2011	3.30
2012	1.88
2013	0.19
Total	**5.37**

The table below reflects the fair value of derivative instruments and their effect on our unaudited condensed balance sheet for the period ended June 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	**$2,293**
Natural Gas Swaps	Receivables	**(141)**
Total assets designated as hedges under authoritative guidance related to derivatives and hedging activities		**$2,152**
Liabilities		
Natural Gas Swaps	Other current liabilities	**$2,293**
Natural Gas Swaps	Other current liabilities	**(141)**
Total liabilities designated as hedges under authoritative guidance related to derivatives and hedging activities		**$2,152**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities:		
Assets		
Nuclear decommissioning trust	Decommissioning fund	**$ 657**
Nuclear decommissioning trust	Decommissioning fund	**(1,162)**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**381**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**(452)**
Total not designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ (576)**

The following table presents the gains and (losses) on derivative instruments recognized in margins for the three and six months ended June 30, 2011.

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

	Statement of Revenues and Expenses Location	Three months ended	Six months ended
		(dollars in thousands)	
Designated as hedges under authoritative guidance related to derivatives and hedging activities			
Natural Gas Swaps	Purchase power	**$ 74**	**$ 96**
Natural Gas Swaps	Purchase power	**(972)**	**(1,255)**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities			
Nuclear decommissioning trust	Investment income	**830**	**1,070**
Nuclear decommissioning trust	Investment income	**(322)**	**(572)**
Total losses on derivatives		**$(390)**	**$ (661)**

(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 June 30, 2011 and December 31, 2010. All realized and unrealized gains and losses were determined using the specific identification method. Approximately 60% of these gross unrealized losses were in effect for less than one year. These losses were primarily due to investments in fixed income 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 regulatory asset.

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

		(dollars in thousands)		
		Gross Unrealized		
June 30, 2011	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$147,061**	**$43,976**	**$(2,648)**	**$188,389**
Debt	**161,122**	**9,040**	**(4,627)**	**165,535**
Other	**8,476**	**382**	**(452)**	**8,406**
Total	**$316,659**	**$53,398**	**$(7,727)**	**$362,330**

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 fiscal years 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 fiscal years ending December 31, 2011. Our adoption of the standard will not have a material effect on our disclosures.

(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 March 31, 2010	$(1,004)	$(1,004)
Unrealized gain	784	784
Balance at June 30, 2010	$ (220)	$ (220)
Balance at March 31, 2011	$ (490)	$ (490)
Unrealized gain	613	613
Balance at June 30, 2011	**$ 123**	**$ 123**

	Accumulated Other Comprehensive Margin (Deficit) Six Months Ended	
	(dollars in thousands)	
	Available-for-sale Securities	Total
Balance at December 31, 2009	$(1,253)	$(1,253)
Unrealized gain	1,033	1,033
Balance at June 30, 2010	$ (220)	$ (220)
Balance at December 31, 2010	$ (469)	$ (469)
Unrealized gain	592	592
Balance at June 30, 2011	**$ 123**	**$ 123**

(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 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 Cash.* The restricted cash balance at June 30, 2011 of $3,770,000 primarily consisted of clean renewable energy bond proceeds on deposit with CoBank, N.A. to fund a clean renewable energy project at the Rocky Mountain Pumped Storage Hydroelectric facility.

(I) *Restricted Short-term Investments.* At June 30, 2011, we had $15,626,000 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.

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

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

	2011	2010
	(dollars in thousands)	
Premium and loss on reacquired debt	**$105,052**	$111,570
Deferred amortization on capital leases	**55,555**	64,561
Deferred outage costs	**42,441**	23,796
Deferred interest rate swap termination fees	**23,310**	25,306
Asset retirement obligations	**9,803**	15,699
Deferred depreciation expense	**51,921**	52,632
Deferred investment impairment losses	**4,692**	5,214
Deferred charges related to Plant Vogtle Units 3 and 4 training costs	**13,460**	9,707
Deferral of effects on net margin—Murray Energy Facility	**4,014**	—
Other regulatory assets	**2,612**	2,651
Accumulated retirement costs for other obligations	**(37,546)**	(39,205)
Net benefit of Rocky Mountain transactions	**(49,373)**	(50,965)
Deferral of effects on net margin—Hawk Road Energy Facility	**(14,898)**	(21,956)
Major maintenance sinking fund	**(29,009)**	(28,500)
Deferred debt service adder	**(32,639)**	(27,678)
Other regulatory liabilities	**(1,772)**	(1,931)
Net regulatory assets	**$147,623**	$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.

(K) *Member Power Bill Prepayments.* We have a power bill prepayment program pursuant to which members can prepay their power bills from us at a discount based on our avoided cost of borrowing. The prepayments are credited against the participating members' power bills in the month(s) agreed upon in advance. The discounts are credited against the power bills and are recorded as a reduction to member revenues. At June 30, 2011, member power bill prepayments as reflected on the unaudited condensed balance sheet, including unpaid discounts, were $70,540,000, of which, $40,620,000 is classified as a current liability and $29,920,000 as deferred credits and other liabilities. The prepayments are being applied against members' power bills through May 2015, with the majority of the remaining balance scheduled to be applied by the end of 2012.

(L) *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 initial interest rate on the term loan is set at a 1.25% spread to the 6-month LIBOR (1.69%) with interest payments due in July and October 2011. The term loan is set to mature in April 2014. For a discussion of the Murray acquisition, see Note M.

As of June 30, 2011, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $353,571,000 to permanently finance the Hartwell and Hawk Road acquisitions and for general improvements at existing plants.

(M) *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 are recorded in the accompanying statement of revenues and expenses for the quarter ended June 30, 2011), we funded the entire $531,272,000 cash outlay by closing a $260,000,000 three-year term loan and by financing the remaining $271,272,000 through the issuance of commercial paper and draws under existing credit facilities.

The following amounts represent the preliminary estimates of 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	4.5
Power purchase and sale agreement	40.4
Emission Credits	0.2
Current liabilities	(6.5)
Total identifiable net assets	**$ 529.3**

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 quarter ended June 30, 2011 include $51,921,000 related to capacity and energy sales from Murray. Prior to our members taking the output from Murray, the net results of operations from Murray, including related interest costs, are being deferred as a regulatory asset. This regulatory asset will be amortized over the remaining life of the plant (estimated to be 30 years) beginning January 2016. For the quarter ended June 30, 2011, we deferred $4,014,000 in excess costs from Murray.

(N) *Sales to Non-Members.* For the six-months ended June 30, 2011, we had $52,353,000 of sales to non-members consisting primarily of capacity and energy sales to Georgia Power under an agreement to sell the entire output of recently acquired Murray Unit No. 1 through May 31, 2012. In addition, sales to non-members were derived from sales of energy generated at Murray Unit No. 2.

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 Six Months Ended June 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 six-month periods ended June 30, 2011 was $12.7 million and $28.8 million compared to $7.4 million and $22.0 million for the same periods of 2010. We expect a net margin of $38.0 million for the year ending December 31, 2011, which will achieve, but not exceed, the targeted margins for interest ratio of 1.14.

Operating Revenues

Our operating revenues fluctuate from period to period based on several factors, including weather and other seasonal factors, load requirements in our members' service territories, operating costs, availability of electric generation resources, our decisions of whether to dispatch our owned or purchased resources or member-owned resources over which we have dispatch rights, and members' decisions of whether to purchase a portion of their hourly energy requirements from our resources or from other suppliers.

Sales to Members. Total revenues from sales to members increased 0.6% and decreased 5.2% in the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010. Megawatt-hour sales to members decreased 6.9% and 13.7% for the three-month and six-month periods ended June 30, 2011 versus the same periods of 2010. The average total revenue per megawatt-hour from sales to members increased 8.1% and 9.9% for the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	**2011**	2010
Capacity revenues	**$ 171,478**	$ 171,443	**$ 343,479**	$ 342,218
Energy revenues	**156,298**	154,520	**253,745**	287,573
Total	**$ 327,776**	$ 325,963	**$ 597,224**	$ 629,791
Kilowatt-hours sold to members	**5,341,362**	5,735,490	**9,324,218**	10,801,711
Cents per kilowatt-hour	**6.14¢**	5.68¢	**6.41¢**	5.83¢

Energy revenues were 1.2% higher and 11.8% lower for the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010. Our average energy revenue per megawatt-hour from sales to members were 8.6% and 2.2% higher for the three-month and six-month periods ended June 30, 2011 as compared to the same periods of 2010. The changes in energy revenues resulted from the pass-through to our members of fuel costs associated with higher gas-fired generation during the second quarter of 2011 as compared to the same quarter of 2010 and from substantially lower coal-fired generation due to a scheduled outage at Plant Scherer for the six-month period ended June 30, 2011 as compared to the same period of 2010. For a discussion of fuel costs, see "*—Operating Expenses.*"

Sales to Non-Members. Sales to non-members for the three-month and six-month periods ended June 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, sales to non-members were derived from sales of energy generated at Murray Unit No. 2. See Note M of Notes to Unaudited Condensed Financial Statements for further discussion of our acquisition of Murray.

Operating Expenses

Operating expenses for the three-month and six-month periods ended June 30, 2011 increased 18.7% and 3.1% compared to the same periods of 2010. This 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 June 30,			
	2011		2010	
Fuel Source	**Cost**	**Generation**	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal	**$ 72,342**	**2,315,372**	$ 76,486	2,719,658
Nuclear	**18,373**	**2,308,955**	16,860	2,505,589
Gas	**70,037**	**1,732,957**	27,853	604,876
Pumped Storage	**603**	**246,712**	286	265,768
	$161,355	**6,603,996**	$121,485	6,095,891
	Cost	**Purchased**	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power	**$ 13,600**	**39,471**	$ 18,217	103,505

	Six Months Ended June 30,			
	2011		2010	
Fuel Source	**Cost**	**Generation**	Cost	Generation
	(thousands)	(Mwh)	(thousands)	(Mwh)
Coal	**$122,906**	**3,997,491**	$145,081	5,281,305
Nuclear	**34,516**	**4,705,954**	29,809	4,689,037
Gas	**75,128**	**1,755,868**	47,819	966,234
Pumped Storage	**1,256**	**429,864**	867	420,993
	$233,806	**10,889,177**	$223,576	11,357,569
	Cost	**Purchased**	Cost	Purchased
	(thousands)	(Mwh)	(thousands)	(Mwh)
Purchased Power	**$ 25,155**	**60,678**	$ 35,625	226,628

For the three-month and six-month periods ended June 30, 2011, total fuel costs increased 32.8% and 4.6% and total megawatt-hour generation increased 8.3% and decreased 4.1% compared to the same periods of 2010. Average fuel costs per megawatt-hour increased 22.6% and 9.1% in the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010. The increase in total fuel costs (as well the increase in generation for the current quarter) resulted primarily from increased natural gas-fired generation of 186.5% or 1,128,000 megawatt-hours and 81.7% or 790,000 megawatt-hours for the three-months and six-months ended June 30, 2011 as compared to the same periods of 2010 primarily due to generation from Murray (which was utilized for sales to non-members). In addition, generation from Chattahoochee (which was placed back into operation in April 2011 after completion of an unplanned outage) contributed to the increased generation during the current quarter. These increases were offset somewhat by a decrease in generation for the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010 of 17.2% or 319,000 megawatt-hours and 30.8% or 1,176,000 megawatt-hours in coal-fired generation primarily at Plant Scherer due to a scheduled outage 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 4.6% and 9.7% for the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010. The increase in production costs for the current quarter ended June 30, 2011 compared to the same period of 2010 was primarily due to operation and maintenance expenses incurred at Murray. For the six-month period ended June 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 and Scherer. These increases were offset somewhat by lower operations and maintenance costs at Hartwell; 2010 operations and maintenance costs for Hartwell were higher due to major outage costs incurred for a hot gas path inspection.

Depreciation and amortization costs increased 47.2% and 24.4% for the three-month and six-month periods ended June 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 25.3% and 29.4% for the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010. Purchased megawatt-hours decreased 61.9% and 73.2% for the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010. The decrease in purchased power costs resulted from a decrease 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 and from 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 increased 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.*"

Interest charges

Interest expense increased by 10.3% and 9.0% in the three-month and six-month periods ended June 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 104.6% and 81.8% in the three-month and six-month periods ended June 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 9.3% and 12.5% in the three-month and six-month periods ended June 30, 2011 compared to the same periods of 2010 primarily due to the completion of amortization 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 June 30, 2011

Assets

Cash used for property additions for the six-month period ended June 30, 2011 totaled $397.2 million. Of this amount, $208.7 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 $254.3 million in the six-month period ended June 30, 2011. The decrease can be attributed primarily to capital expenditures of $397.2 million for property additions and principal and interest payments of $387.7 million, which were partially offset by increased borrowings and the use of restricted short-term investments. In addition, $529.3 million of cash was utilized for the Murray acquisition; however, the acquisition was entirely financed by 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 $3.8 million restricted cash balance at June 30, 2011 primarily consisted of clean renewable energy bond proceeds on deposit with CoBank, N.A. to fund a clean renewable energy project at the Rocky Mountain Pumped Storage Hydroelectric facility.

The $15.6 million of restricted short-term investments at June 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 I of Notes to Unaudited Condensed Financial Statements and "—Capital Requirements and Liquidity and Sources of Capital—*Liquidity.*"

Receivables increased by $58.5 million in the six-month period ended June 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. The receivable for amounts billed or billable to the members for their monthly power bills also increased by approximately $20.4 million in June 2011 compared to December 2010. This increase was primarily due to higher energy costs during the period, which was a result of increased generation. Receivables from Smarr EMC for costs incurred for operation of its facilities also increased by $5.0 million.

Inventories, at average cost, increased $33.0 million in the six-month period ended June 30, 2011 due to inventory acquired in connection with the Murray acquisition.

Other deferred charges increased $33.7 million in the six-month period ended June 30, 2011 primarily due to the $29.7 million amortized value of the intangible asset associated with the purchase and sale agreement with Georgia Power, acquired as part of the Murray acquisition.

Equity and Liabilities

Long-term debt increased $587.3 million for the six-month period ended June 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. During the second quarter of 2011, we received advances on Rural Utilities Service-guaranteed Federal Financing Bank loans totaling $276.6 million to permanently finance the Hartwell and Hawk Road acquisitions.

Long-term debt and capital leases due within one year decreased $36.6 million primarily as a result of scheduled debt maturities and the reclassification of certain long-term debt.

Short-term borrowings for the six-month period ended June 30, 2011 increased $47.7 million. The increase was primarily due to the issuance of commercial paper to fund capital expenditures for Vogtle Units No. 3 and No. 4 and the Murray acquisition. Largely offsetting these increases was the repayment of commercial paper issued to provide interim financing of the 2009 Hartwell and Hawk Road acquisitions.

Accounts payable increased $50.3 million in the six-month period ended June 30, 2011 primarily due to an $18.7 million increase 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. In addition, there was a $26.1 million increase in the payable for natural gas, primarily due to an increase in natural gas-fired generation at Murray and Chattahoochee. At December 31, 2010, Chattahoochee was in an unplanned outage and did not resume operation until April 2011.

The $22.8 million decrease in accrued interest for the six-month period ended June 30, 2011 was due to the normal timing differences between interest payments and interest expense accruals.

Accrued and withheld taxes decreased $7.6 million for the six-month period ended June 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 June 30, 2011, $40.6 million of member power bill prepayments was classified as a current liability and $29.9 million of member power bill prepayments was classified as a long-term liability. During the six-month period ended June 30, 2011, approximately $13.8 million of prepayments were received from the members and approximately $55.7 million was applied to the members' monthly power bills. For information regarding the power bill prepayment program, see Note K of Notes to Unaudited Condensed Financial Statements and "—Capital Requirements and Liquidity and Sources of Capital—*Liquidity.*"

Capital Requirements and Liquidity and Sources of Capital

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 purchase 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. In June 2011, Westinghouse Electric Company, LLC submitted an AP1000 Design Certification Amendment to the Nuclear Regulatory Commission. In a letter dated August 2, 2011, the Nuclear Regulatory Commission clarified the timeframe for approval of the combined construction permits and operating licenses for Vogtle Units No. 3 and No. 4, which continues to allow for issuance in late 2011. On August 5, 2011, the Nuclear Regulatory Commission announced that it had completed the Final Safety Evaluation Report for both the Westinghouse AP1000 Design Certification Document and combined construction permits and operating licenses. Based on this positive development, Georgia Power expects the Nuclear Regulatory Commission to approve the Design Certification Amendment 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 Georgia Power's request for a second limited work authorization, which would allow Georgia Power to perform additional construction activities related to the nuclear island in fall 2011 and obtain commercial operation in 2016 and 2017 for 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 and 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 June 30, 2011, our total capitalized costs to date for Vogtle Units No. 3 and No. 4 was $1.1 billion.

Recent Events in Japan. On March 11, 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 situation 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 events in Japan have created broader economic uncertainties that may affect the availability of equipment from Japanese manufacturers and future operating costs, including fuel, for our nuclear and other generating facilities. The Nuclear Regulatory Commission plans to perform additional operational and safety reviews of nuclear facilities in the United States, which could potentially impact future operations and capital requirements. As a first step in this review, 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. 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 any 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 annual report 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. Based on member requests, we are currently developing two rate management programs that could be offered to members that have subscriptions in the Plant Vogtle units under construction and Murray. The first program would provide members with an opportunity to expense interest during construction on the Plant Vogtle units, and the second program would allow members to expense rather than defer the carrying costs associated with Murray. See Note J of Notes to Unaudited Condensed Financial Statements for a discussion of the deferred carrying costs associated with Murray. Each subscribing member would be able to elect to participate in one or both of these programs. The Plant Vogtle rate management program would be available starting in 2012 and would allow each subscribing member to make an annual election to expense some or all of its allocated portion of interest during construction for the following year, although only current year costs could be expensed. The Murray rate management program would be available by or before 2012 and would allow each subscribing member to make a monthly election to expense some or all of its allocated portion of Murray's carrying costs that would otherwise be deferred. These rate management programs are subject to approval by our board of directors and member elections to participate, and the associated rate change is subject to approval by the Rural Utilities Service.

Environmental Regulations

Recently, the Environmental Protection Agency has proposed or finalized a number of rules that would significantly expand the scope of regulations governing air emissions, water intake and waste management at power plants. See "Item 1A—RISK FACTORS" in our 2010 Annual Report for further discussion regarding potential effects on our business from environmental regulation.

In July 2011, EPA finalized the Cross-State Air Pollution Rule that contains new sulfur dioxide and nitrogen oxides emission reduction requirements for existing electric generating units located in most states east of the Mississippi, including Georgia. The rule, which replaced the Clean Air Interstate Rule, imposes emission caps in each affected state. Georgia is affected by the rule's summer ozone season nitrogen oxides allowance trading program and the annual sulfur dioxide and nitrogen oxides allowance trading programs for particulate matter. In order to comply with this rule in 2012, we may need to either purchase emission allowances or limit operations at Plant Scherer during off-peak periods or some combination of the two. We expect that additional emission control equipment at Plant Scherer will be installed and operational beginning in 2013 and that emission allowance purchases or limiting of operations will cease to be necessary. The ultimate outcome of this rule will depend on the result of any legal challenges; however, it 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. These regulations could require the installation of additional emission control technologies, including activated carbon injection and baghouses at Plant Wansley. Emission control projects are already underway at Plant Scherer and were included in our projected capital expenditures disclosed in our 2010 Form 10-K. The Plant Scherer projects are expected to be completed by 2014 and cost approximately $820 million, which includes approximately $230 million spent to date. If required, baghouses at Plant Wansley, which were not included in the projected capital expenditures disclosed in our 2010 Form 10-K, would likely be installed from 2014 through 2016 at an approximate cost to us of $150 million. Although EPA has agreed to a consent decree by which it must issue a final EGU MACT rule by November 16, 2011, the court could extend this deadline. The total cost of compliance will depend on the final rule and the outcome of any legal challenges and cannot be determined with certainty at this time.

In April 2011, EPA proposed new national requirements to reduce the impact on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. Termed the 316(b) rule, this proposal focuses primarily on requiring utilities to add cooling towers at power plants that currently have "once-through" cooling systems. The 316(b) rule would affect existing power generating facilities permitted to withdraw more than two million gallons per day from waters of the United States and using at least 25% of the water exclusively for cooling. The proposed regulations would likely apply to Plants Hatch, Scherer, Vogtle and Wansley; however, each of these plants already has operational cooling towers and any effects are not expected to be significant. EPA has agreed to issue a final rule in July 2012 and its ultimate effects will depend on the final rule and any legal challenges.

Finally, in 2010 EPA proposed two alternative proposals for regulating coal combustion byproducts from electric utilities: regulation listed as "special wastes" under hazardous waste rules or as solid wastes. EPA received numerous comments from utilities and industry groups regarding the potential costs and operating effects associated with the adoption of the proposed rules and has delayed release of the final rule until it can consider all of the comments. Adoption of either approach may require closure of or significant changes to existing storage units, extended plant outages, construction of lined landfills and groundwater monitoring facilities, and additional material management and financial assurance requirements. Depending upon which method of regulation EPA selects, if any, preliminary assessments indicate that our share of capital costs at Plants Scherer and Wansley could be approximately half of a billion dollars or potentially more. Estimated costs are based on pre-screening figures that should be distinguished from the more formalized cost estimates provided for projects that are more definite as to scope and timing and the ultimate impacts associated with either proposal cannot be determined with certainty at this time.

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 these new regulations. For further discussion regarding environmental regulations and capital requirements, see "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 June 30, 2011, we had $1.68 billion of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $418 million in cash and cash equivalents and $1.26 billion of unused and available committed credit arrangements.

As discussed in our Form 8-K dated June 9, 2011, we recently completed a major component of our planned liquidity restructuring which increased our liquidity by over $600 million. At June 30, 2011, we had in excess of $1.86 billion of committed credit arrangements in place comprised of the five separate facilities reflected in the table below.

Committed Credit Facilities			
	Authorized Amount	Available 6/30/2011	Expiration Date
	(dollars in millions)		
Unsecured Facilities:			
Syndicated Line of Credit[1]	$1,265	$ 778[2]	June 2015
CFC Line of Credit	50	50	October 2011
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	**$1,865**	**$1,261**	

(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, $352 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.

The final component of our liquidity restructuring plan is to renew and upsize our $50 million unsecured line of credit with National Rural Utilities Cooperative Finance Corporation (CFC) as a new five-year $110 million unsecured line of credit. Both our board of directors and CFC's board of directors have approved this new facility, and we expect to have it in place before the existing credit facility expires on October 1, 2011. When completed, we will have credit facilities in place that in the aggregate total $1.93 billion. We believe this amount of liquidity will be more than sufficient to cover our interim funding needs through the period of generation expansion and to provide a reasonable cushion for our normal business operations.

Due to the significant expenditures we are incurring relating to environmental compliance projects and acquiring and constructing new generation facilities, we are currently funding our capital requirements through a combination of funds generated from operations and interim and long-term borrowings. In particular, we are currently 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.

In the third quarter of 2011, we plan to issue at least $300 million of long-term first mortgage bonds to fund a portion of the cost of constructing the additional units at Plant Vogtle and use the bond proceeds to repay commercial paper providing interim funding for this same purpose. A similar repayment of commercial paper and other interim borrowings relating to the Plant Vogtle construction occurred in connection with the issuances of $450 million and $400 million of long-term first mortgage bonds in November 2010 and November 2009, respectively. For a more detailed discussion of our plans regarding financing of these facilities, see "—*Financing Activities*."

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 $850 million in the aggregate, of which $597 million remained available at June 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 June 30, 2011, the required minimum level was $575 million and our actual patronage capital was $625 million. Additional covenants contained in several of our credit facilities limit the amount of secured indebtedness and unsecured indebtedness we can have outstanding. At June 30, 2011, the most restrictive of these covenants limits our secured indebtedness to $9.5 billion and our unsecured indebtedness to $4.0 billion. At June 30, 2011, we had $5.3 billion of secured indebtedness and $424 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 June 30, 2011, the balance of member prepayments received but not yet credited to their power bills was $70.5 million. We expect to apply the prepayments against the participating members' power bills through May 2015, 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 K of Notes to Unaudited Condensed Financial Statements.

At June 30, 2011, current assets included $15.6 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 June 30, 2011, we had $5.1 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. In the third quarter of 2011, we plan to issue at least $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 will be secured under our first mortgage indenture.

Interim Financing for the Murray Acquisition. On April 6, 2011, we closed a $260 million three-year term loan with three banks to provide funds for a portion of the cost of acquiring Murray. The balance of the purchase price, $269 million, was funded with commercial paper.

Rural Utilities Service-Guaranteed Loans. We currently have five approved Rural Utilities Service-guaranteed loans, being funded through the Federal Financing Bank, totaling $1.17 billion that are in the process of being drawn down, with $681 million remaining to be advanced.

We also have two Rural Utilities Service-guaranteed loan applications pending, totaling $994 million, including loan applications related to the Warren County biomass plant, which has been deferred, and Murray. Action on the Murray loan is anticipated in 2011.

The Federal budget for fiscal year 2011, which began on October 1, 2010, was adopted in April 2011. Rural Utilities Service funding levels and loan type eligibility for fiscal year 2011 remain unchanged from that in fiscal year 2010. However, the President's proposed budget for fiscal year 2012 does include a modest reduction to the overall funding level as well as prohibitions against funding for (i) improvements to fossil-fueled generation unless the improvements are related to carbon-capture projects, except up to $2 billion may be used for environmental improvements that would reduce emissions, and (ii) construction of new fossil-fueled generation facilities. Nonetheless we have submitted a loan application for Murray, and should members subscribe to any additional fossil-fueled facilities, we anticipate filing loan applications for those facilities to the extent Rural Utilities Service lending authority in place at that time allow us to do so. For any amounts not funded through the Rural Utilities Service, we would most likely issue taxable bonds.

All of the approved Rural Utilities Service loans are expected to be funded through the Federal Financing Bank and guaranteed by the Rural Utilities Service, and 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 share of 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. 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, negotiation of definitive agreements, 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 Plant Vogtle 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 $850 million through the issuance of first mortgage bonds. As discussed above, we expect to issue at least another $300 million of first mortgage bonds for this purpose in the third quarter of 2011.

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.

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

Our market risks have not changed materially from the risks reported in our 2010 Form 10-K.

Item 4. Controls and Procedures

As of June 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.

As a result of our acquisition of Murray on April 8, 2011, our internal control over financial reporting, subsequent to the date of the acquisition, includes certain additional internal controls relating to Murray. Except for these additional controls as described above, there have been no changes in our internal control over financial reporting or other factors that occurred during the quarter ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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: August 11, 2011 By: /s/ Thomas A. Smith

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

Date: August 11, 2011 /s/ Elizabeth B. Higgins

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