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, 2010

OR

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

For the transition period from to

Commission File No. 000-53908

Oglethorpe Power Corporation

(An Electric Membership Corporation)

(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). **Yes** ☐ **No** ☐

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). **Yes** ☐ **No** ☒

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. **The registrant is a membership corporation and has no authorized or outstanding equity securities.**

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OGLETHORPE POWER CORPORATION
INDEX TO QUARTERLY REPORT ON FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2010

PART I—FINANCIAL INFORMATION
Item 1. Financial Statements

Oglethorpe Power Corporation
Condensed Balance Sheets (Unaudited)
June 30, 2010 and December 31, 2009

	(dollars in thousands)	
	2010	2009
Assets		
Electric plant:		
In service	**$ 6,651,340**	$ 6,550,938
Less: Accumulated provision for depreciation	**(3,052,840)**	(2,993,215)
	3,598,500	3,557,723
Nuclear fuel, at amortized cost	**240,233**	215,949
Construction work in progress	**870,870**	626,824
	4,709,603	4,400,496
Investments and funds:		
Decommissioning fund	**234,232**	239,746
Deposit on Rocky Mountain transactions	**119,542**	115,641
Investment in associated companies	**55,329**	53,199
Long-term investments	**86,396**	87,129
Other, at cost	**3,598**	4,597
	499,097	500,312
Current assets:		
Cash and cash equivalents, at cost	**362,949**	579,069
Restricted cash, at cost	**8,021**	22,405
Restricted short-term investments	**122,872**	80,590
Receivables	**155,793**	110,258
Inventories, at average cost	**194,684**	209,837
Prepayments and other current assets	**11,340**	9,393
	855,659	1,011,552
Deferred charges:		
Premium and loss on reacquired debt, being amortized	**118,094**	122,847
Deferred amortization of capital leases	**72,213**	77,755
Deferred debt expense, being amortized	**55,915**	57,262
Deferred outage costs, being amortized	**40,023**	31,319
Deferred tax assets	**24,000**	24,000
Deferred asset associated with retirement obligations	**45,126**	31,413
Deferred interest rate swap termination fees, being amortized	**27,301**	29,296
Deferred depreciation expense, being amortized	**53,344**	54,056
Other	**26,934**	29,926
	462,950	457,874
	$ 6,527,309	$ 6,370,234

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

Oglethorpe Power Corporation
Condensed Balance Sheets (Unaudited)
June 30, 2010 and December 31, 2009

	(dollars in thousands)	
	2010	2009
Equity and Liabilities		
Capitalization:		
Patronage capital and membership fees	**$ 584,223**	$ 562,219
Accumulated other comprehensive deficit	**(220)**	(1,253)
	584,003	560,966
Long-term debt	**4,191,462**	4,178,981
Obligation under capital leases	**191,446**	208,945
Obligation under Rocky Mountain transactions	**119,542**	115,641
	5,086,453	5,064,533
Current liabilities:		
Long-term debt and capital leases due within one year	**146,705**	119,241
Short-term borrowings	**410,879**	283,634
Accounts payable	**102,528**	24,184
Accrued interest	**49,589**	50,947
Accrued and withheld taxes	**14,881**	24,864
Member power bill prepayments, current	**85,791**	182,514
Other current liabilities	**24,610**	28,000
	834,983	713,384
Deferred credits and other liabilities:		
Gain on sale of plant, being amortized	**29,825**	31,062
Net benefit of Rocky Mountain transactions, being amortized	**52,558**	54,151
Asset retirement obligations	**273,132**	264,635
Accumulated retirement costs for other obligations	**39,374**	43,955
Long-term contingent liability	**24,000**	24,000
Member power bill prepayments, non-current	**24,366**	18,000
Power sale agreement, being amortized	**77,846**	86,211
Other	**84,772**	70,303
	605,873	592,317
	$6,527,309	$6,370,234

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, 2010 and 2009

	(dollars in thousands)			
	Three Months		Six Months	
	2010	2009	**2010**	2009
Operating revenues:				
Sales to Members	**$325,963**	$300,527	**$629,791**	$582,232
Sales to non-Members	**147**	332	**392**	640
Total operating revenues	**326,110**	300,859	**630,183**	582,872
Operating expenses:				
Fuel	**121,459**	98,545	**223,551**	187,119
Production	**85,878**	69,269	**163,261**	140,033
Purchased power	**18,217**	34,050	**35,625**	59,196
Depreciation and amortization	**36,505**	32,827	**73,515**	63,711
Accretion	**4,282**	4,566	**8,566**	9,131
Total operating expenses	**266,341**	239,257	**504,518**	459,190
Operating margin	**59,769**	61,602	**125,665**	123,682
Other income:				
Investment income	**7,497**	8,561	**15,153**	16,063
Other	**2,901**	2,308	**6,182**	5,266
Total other income	**10,398**	10,869	**21,335**	21,329
Interest charges:				
Interest on long-term debt and capital leases	**63,174**	59,439	**127,541**	115,575
Other interest	**2,381**	587	**3,602**	1,204
Allowance for debt funds used during construction	**(8,676)**	(4,739)	**(18,137)**	(8,544)
Amortization of debt discount and expense	**5,888**	4,375	**11,990**	8,320
Net interest charges	**62,767**	59,662	**124,996**	116,555
Net margin	**$ 7,400**	$ 12,809	**$ 22,004**	$ 28,456

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 Deficit (Unaudited)
For the Six Months Ended June 30, 2010 and 2009

(dollars in thousands)

	Patronage Capital and Membership Fees	Accumulated Other Comprehensive (Deficit)	Total
Balance at December 31, 2008	$535,829	$(1,348)	$534,481
Components of comprehensive margin:			
Net margin	28,456	—	28,456
Unrealized loss on available-for-sale securities	—	(79)	(79)
Total comprehensive margin			28,377
Balance at June 30, 2009	$564,285	$(1,427)	$562,858
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**

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, 2010 and 2009

	(dollars in thousands)	
	2010	2009
Cash flows from operating activities:		
Net margin	**$ 22,004**	$ 28,456
Adjustments to reconcile net margin to net cash provided (used) by operating activities:		
Depreciation and amortization, including nuclear fuel	**129,788**	109,999
Accretion cost	**8,566**	9,131
Amortization of deferred gains	**(2,830)**	(2,830)
Allowance for equity funds used during construction	**(994)**	(1,406)
Deferred outage costs	**(25,080)**	(18,402)
(Gain) loss on sale of investments	**(9,015)**	13,981
Regulatory deferral of costs associated with nuclear decommissioning	**4,422**	(19,413)
Other	**(2,438)**	65
Change in operating assets and liabilities:		
Receivables	**(44,018)**	(28,370)
Inventories	**15,153**	(15,850)
Prepayments and other current assets	**(1,946)**	(933)
Accounts payable	**5,935**	(11,184)
Accrued interest	**(1,358)**	14,745
Accrued and withheld taxes	**(9,982)**	(4,885)
Other current liabilities	**(5,197)**	375
(Decrease) increase in Member power bill prepayments	**(90,357)**	180,753
Total adjustments	**(29,351)**	225,776
Net cash (used in) provided by operating activities	**(7,347)**	254,232
Cash flows from investing activities:		
Property additions	**(335,145)**	(270,099)
Plant acquisition	**—**	(105,008)
Activity in decommissioning fund—Purchases	**(299,446)**	(351,150)
—Proceeds	**296,933**	348,283
Activity in bond, reserve and construction funds—Purchases	**(104)**	(4)
—Proceeds	**1,105**	1,049
Decrease in restricted cash and cash equivalents	**14,383**	10,255
Increase in restricted short-term investments	**(42,282)**	(80,756)
Activity in investment in associated organizations—Purchases	**(4,012)**	(11,254)
—Proceeds	**2,505**	967
Activity in other long-term investments—Purchases	**(2,367)**	(742)
—Proceeds	**2,700**	200
Other	**5,348**	(493)
Net cash used in investing activities	**(360,382)**	(458,752)
Cash flows from financing activities:		
Long-term debt proceeds	**222,631**	408,900
Long-term debt payments	**(200,197)**	(65,552)
Increase in short-term borrowings	**127,245**	81,974
Other	**1,930**	(6,240)
Net cash provided by financing activities	**151,609**	419,082
Net (decrease) increase in cash and cash equivalents	**(216,120)**	214,562
Cash and cash equivalents at beginning of period	**579,069**	167,659
Cash and cash equivalents at end of period	**$ 362,949**	$ 382,221
Supplemental cash flow information:		
Cash paid for—		
Interest (net of amounts capitalized)	**$ 108,629**	$ 93,489
Supplemental disclosure of non-cash investing and financing activities:		
Plant expenditures included in ending accounts payable	**$ 73,221**	$ 20,686
Acquired power purchase and sale liability	**$ —**	$ 98,100

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

Oglethorpe Power Corporation
Notes to Unaudited Condensed Financial Statements
June 30, 2010 and 2009

(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, 2010 and 2009. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to SEC rules and regulations, although we believe that the disclosures are adequate to make the information presented not misleading. These 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, 2009, as filed with the SEC. The results of operations for the three- and six-month periods ended June 30, 2010 are not necessarily indicative of results to be expected for the full year. As noted in our 2009 Form 10-K, substantially all of our sales are to our 39 electric distribution cooperative members and, thus, the receivables on the accompanying balance sheets are principally from our members. (See "Notes to Financial Statements" in our 2009 Form 10-K.)

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

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

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

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

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

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

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

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

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

The tables below detail assets and liabilities measured at fair value on a recurring basis for the periods ended June 30, 2010 and December 31, 2009.

		Fair Value Measurements at Reporting Date Using		
	June 30, 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	**$ 78,865**	$ 78,865	$ —	$ —
Corporate bonds	**50,815**	50,815	—	—
International equity	**34,388**	34,388	—	—
US Treasury and government agency securities	**46,943**	46,943	—	—
Mortgage and asset backed securities	**20,015**	20,015	—	—
Municipal bonds	**1,704**	1,704	—	—
Derivative instruments	**(311)**	—	—	(311)
Other	**1,813**	1,813	—	—
Bond, reserve and construction funds	**2,982**	2,982	—	—
Long-term investments	**86,396**	61,911	—	24,485(1)
Natural gas swaps	**(14,381)**	—	(14,381)	—
Deposit on Rocky Mountain transactions	**119,542**	—	—	119,542
Investments in associated companies	**55,329**	—	—	55,329
Total	**$484,100**	$299,436	$(14,381)	$199,045

	December 31, 2009	Fair Value Measurements at Reporting Date Using — Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(dollars in thousands)			
Decommissioning funds				
Domestic equity	$ 89,723	$ 89,723	$ —	$ —
Corporate bonds	48,317	48,317	—	—
International equity	40,951	40,951	—	—
US Treasury and government agency securities	35,137	35,137	—	—
Mortgage and asset backed securities	21,383	21,383	—	—
Preferred stock	1,463	—	1,463	—
Municipal bonds	1,267	1,267	—	—
Derivative instruments	(260)	—	—	(260)
Other	1,765	1,765	—	—
Bond, reserve and construction funds	3,982	3,982	—	—
Long-term investments	87,129	60,119	—	27,010(1)
Natural gas swaps	(12,516)	—	(12,516)	—
Deposit on Rocky Mountain transactions	115,641	—	—	115,641
Investments in associated companies	53,199	—	—	53,199
Total	$487,181	$302,644	$(11,053)	$195,590

(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, 2010 and 2009, respectively.

	Three Months Ended June 30, 2010 — Decommissioning funds	Long-term investments	Deposit on Rocky Mountain transactions	Investments in associated companies
	(dollars in thousands)			
Assets:				
Balance at March 31, 2010	$(435)	$26,376	$117,591	$54,434
Total gains or losses (realized/unrealized):				
Included in earnings (or changes in net assets)	124	—	1,951	895
Impairment included in other comprehensive deficit	—	109	—	—
Purchases, issuances, liquidations	—	(2,000)	—	—
Balance at June 30, 2010	**$(311)**	**$24,485**	**$119,542**	**$55,329**

	Six Months Ended June 30, 2010			
	Decommissioning funds	Long-term investments	Deposit on Rocky Mountain transactions	Investments in associated companies
	(dollars in thousands)			
Assets:				
Balance at January 1, 2010	$(260)	$27,010	$115,641	$53,199
Total gains or losses (realized/unrealized):				
Included in earnings (or changes in net assets)	(51)	—	3,901	2,130
Impairment included in other comprehensive deficit	—	175	—	—
Purchases, issuances, liquidations	—	(2,700)	—	—
Balance at June 30, 2010	**$(311)**	**$24,485**	**$119,542**	**$55,329**

	Three Months Ended June 30, 2009			
	Decommissioning funds	Long-term investments	Deposit on Rocky Mountain transactions	Investments in associated companies
	(dollars in thousands)			
Assets:				
Balance at March 31, 2009	$1,440	$29,619	$110,044	$43,845
Total gains or losses (realized/unrealized):				
Included in earnings (or changes in net assets)	7,221	—	1,824	9,646
Impairment included in other comprehensive deficit	—	(120)	—	—
Purchases, issuances, liquidations	—	(200)	—	—
Balance at June 30, 2009	$8,661	$29,299	$111,868	$53,491

	Six Months Ended June 30, 2009			
	Decommissioning funds	Long-term investments	Deposit on Rocky Mountain transactions	Investments in associated companies
	(dollars in thousands)			
Assets:				
Balance at January 1, 2009	$6,085	$29,643	$108,219	$43,441
Total gains or losses (realized/unrealized):				
Included in earnings (or changes in net assets)	2,576	—	3,649	10,050
Impairment included in other comprehensive deficit	—	(144)	—	—
Purchases, issuances, liquidations	—	(200)	—	—
Balance at June 30, 2009	$8,661	$29,299	$111,868	$53,491

Realized gains and losses included in earnings for the period are reported in other income.

The assets included in the "Long-term investments" column in each of the 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, 2010, we held auction rate securities with maturity dates ranging from March 15, 2028 to December 1, 2045.

At December 31, 2009, we had a total temporary impairment of $1,690,000 on our auction rate securities. Based on the fair value of these auction rate securities as of June 30, 2010, we recorded a reduction to the temporary impairment of approximately $175,000. The temporary impairment is reflected in "Accumulated other comprehensive deficit" on the condensed unaudited balance sheets. The various assumptions we utilize 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, 2010, would have resulted in a decrease in the fair value of our auction rate securities investments by approximately $1,327,000.

These investments were rated either A3 or Aaa by Moody's Investors Service and AAA by Standard and Poor's as of June 30, 2010. Therefore, it is expected that the investments will not be settled at a price less than par value. Because we have the ability and intent to hold these investments until we recover our original investment value, we considered the investments to be only temporarily impaired at June 30, 2010.

(C) *Disclosures about Derivative Instruments and Hedging Activities.* Our executive 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 Activities, 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. 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, 2010, the estimated fair value of our natural gas contracts was an unrealized loss of approximately $14,381,000. 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.

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, 2010, all of the counterparties with transaction amounts outstanding in our hedging portfolio are rated above investment grade by the major rating agencies or have provided a guaranty from one of their affiliates that is rated above 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. We may only post credit support in the form of a letter of credit due to provisions within our Rural Utilities Service Loan Contract; however, we may receive collateral in the form of cash or credit support. As of June 30, 2010, 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, 2010 due to our credit rating being downgraded below investment grade, we could have been required to post letters of credit totaling up to $14,381,000 with our counterparties.

The following table reflects the volume activity of our natural gas derivatives and derivatives within our nuclear decommissioning trust fund as of June 30, 2010 that are expected to settle or mature each year:

Year	**Natural Gas Swaps (MMBTUs)** (in millions)	**Decommissioning Fund Derivative Instruments** (in millions)
2010	5.39	$ 1.60
2011	1.59	(0.60)
2012	0.10	0.80
2013	—	(1.40)
2014	—	(1.92)
2015	—	(2.20)
2016	—	(0.08)
Total	**7.08**	**$(3.80)**

The table below reflects the fair value of derivative instruments and their effect on our condensed unaudited balance sheet for the period ended June 30, 2010.

	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	**$ 14,516**
Natural Gas Swaps	Receivables	**(135)**
Total assets designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 14,381**
Liabilities		
Natural Gas Swaps	Other current liabilities	**$ 14,516**
Natural Gas Swaps	Other current liabilities	**(135)**
Total liabilities designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ 14,381**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities:		
Assets		
Nuclear decommissioning trust	Decommissioning fund	**$ 24,601**
Nuclear decommissioning trust	Decommissioning fund	**(24,912)**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**24,686**
Nuclear decommissioning trust	Deferred asset associated with retirement obligations	**(24,553)**
Total not designated as hedges under authoritative guidance related to derivatives and hedging activities		**$ (178)**

The following table presents the gains and (losses) on derivative instruments recognized in income for the three and six months ended June 30, 2010.

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

	Income Statement 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	**$ (4,194)**	**$(5,441)**
Not designated as hedges under authoritative guidance related to derivatives and hedging activities			
Nuclear decommissioning trust	Investment income	**604**	**1,065**
Nuclear decommissioning trust	Investment income	**(608)**	**(1,049)**
Total losses on derivatives		**$ (4,198)**	**$(5,425)**

(D) *Investments in Debt and Equity Securities:* Under Accounting for Certain 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. There were no held-to-maturity securities as of June 30, 2010 and December 31, 2009. All realized and unrealized gains and losses were determined using the specific identification method. Approximately 30% of these gross unrealized losses were in effect for less than one year. The total gross unrealized 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, 2010 and December 31, 2009:

		(dollars in thousands)		
		Gross Unrealized		
June 30, 2010	**Cost**	**Gains**	**Losses**	**Fair Value**
Equity	**$134,233**	**$20,158**	**$(10,435)**	**$143,956**
Debt	**165,840**	**34,872**	**(28,121)**	**172,591**
Other	**7,043**	**21**	**(1)**	**7,063**
Total	**$307,116**	**$55,051**	**$(38,557)**	**$323,610**

		Gross Unrealized		
December 31, 2009	Cost	Gains	Losses	Fair Value
Equity	$127,704	$35,003	$ (3,671)	$159,036
Debt	170,033	15,685	(13,089)	172,629
Other	(815)	7	—	(808)
Total	$296,922	$50,695	$(16,760)	$330,857

(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. The new guidance provides for improved disclosure requirements about fair value measurements and requires a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers. The guidance also clarifies that fair value measurement disclosures are required for each asset class. In the reconciliation for fair value measurements using significant unobservable inputs (Level 3), the standard also requires a reporting entity to present separately information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one number). We adopted this new guidance beginning with the quarter ended March 31, 2010 except that the requirement to present Level 3 activity separately is not effective for us until the quarter ending March 31, 2011. The adoption of the standard did not have a material effect on our disclosures.

(F) *Accumulated Comprehensive Deficit.* The table below provides detail of the beginning and ending balance for each classification of accumulated other comprehensive 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 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 2009 Form 10-K.

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

	Accumulated Other Comprehensive Deficit Three Months Ended	
	Available-for-sale Securities	Total
Balance at March 31, 2009	$(1,173)	$(1,173)
Unrealized loss	(254)	(254)
Balance at June 30, 2009	$(1,427)	$(1,427)
Balance at March 31, 2010	$(1,004)	$(1,004)
Unrealized gain	784	784
Balance at June 30, 2010	**$ (220)**	**$ (220)**

	Accumulated Other Comprehensive Deficit Six Months Ended	
	Available-for-sale Securities	Total
Balance at December 31, 2008	$(1,348)	$(1,348)
Unrealized loss	(79)	(79)
Balance at June 30, 2009	$(1,427)	$(1,427)
Balance at December 31, 2009	$(1,253)	$(1,253)
Unrealized gain	1,033	1,033
Balance at June 30, 2010	**$ (220)**	**$ (220)**

(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. 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 the future, we may become subject to greenhouse gas emission restrictions as a result of regulation aimed at responding to climate change.

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 "BUSINESS—ENVIRONMENTAL AND OTHER REGULATION" in our 2009 Form 10-K for a more detailed discussion of current and potential future regulations. 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 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. 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, 2010 consisted of $8,021,000 of clean renewable energy bond proceeds on deposit with CoBank to fund a clean renewable energy project at the Rocky Mountain Pumped Storage Hydroelectric facility.

(I) *Restricted short-term investments.* At June 30, 2010, we had $122,872,000 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) *Member Power Bill Prepayments.* In December 2008, we instituted 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 each and every month against the power bills and are recorded on our books as a reduction to member revenues. At June 30, 2010, member power bill prepayments as reflected on the condensed balance sheets, including unpaid discounts, were $110,157,000, of which, $85,791,000 is classified as current liabilities and $24,366,000 as deferred credits and other liabilities in the condensed balance sheets. The prepayments are being applied against members' power bills through May 2015, with the majority scheduled to be applied in 2010.

(K) *New Bond Issuance.* In March 2010, the Development Authority of Burke County (Georgia) and the Development Authority of Monroe County (Georgia) issued, on our behalf, $133,550,000 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 principal payments for the refinanced bonds were made April 1, 2010.

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 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 or above the minimum requirement contained in our 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" contained in our Annual Report on Form 10-K for the fiscal year ended December 31, 2009. 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, 2010 and 2009

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 the 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 the period of generation facility construction, our board of directors approved a budget for 2010 to achieve a 1.14 margins for interest ratio. As our construction program evolves, our board of directors will continue to evaluate the level of margin coverage and may choose to further increase, or decrease, the margins for interest ratio in the future.

Our net margin for the three- and six-month periods ended June 30, 2010 was $7.4 million and $22.0 million compared to $12.8 million and $28.5 million for the same periods of 2009. Through June 30, 2010, we have collected 64% of our expected net margin of $34.3 million for the year ending December 31, 2010. This is typical as our management generally budgets conservatively and makes adjustments to the budget throughout the year so that net margins will achieve, but not exceed, the targeted margins for interest ratio of 1.14.

Operating Revenues

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

Total revenues from sales to members were 8.5% and 8.2% higher in the three- and six-month periods ended June 30, 2010 than for the same periods of 2009. Megawatt-hour sales to members increased 10.7% and 7.9% for the three- and six-month periods ended June 30, 2010 versus the same periods of 2009. The average total revenue per megawatt-hour from sales to members decreased 2.0% and increased 0.3% for the three-and six-month periods ended June 30, 2010 compared to the same periods of 2009.

The components of member revenues for the three- and six-month period ended June 30, 2010 and 2009 were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	**2010**	2009
Capacity revenues	**$ 171,443**	$ 165,197	**$ 342,218**	$ 329,160
Energy revenues	**154,520**	135,330	**287,573**	253,072
Total	**$ 325,963**	$ 300,527	**$ 629,791**	$ 582,232
Kilowatt-hours sold to members	**5,735,490**	5,181,861	**10,801,711**	10,013,239
Cents per kilowatt-hour	**5.68¢**	5.80¢	**5.83¢**	5.81¢

Capacity revenues for the three- and six-month periods ended June 30, 2010 increased 3.8% and 4.0% compared to the same periods of 2009. This increase in capacity revenues partly resulted from higher budgeted fixed operations and maintenance expenses and partly from an increase in the targeted margins for interest ratio to 1.14 in 2010 from 1.12 in 2009. Energy revenues were 14.2% and 13.6% higher for the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. Our average energy revenue per megawatt-hour from sales to members was 3.2% and 5.3% higher for the three- and six-month periods ended June 30, 2010 as compared to the same periods of 2009. The increase in energy revenues was primarily due to the pass-through to our members of higher fuel costs (primarily due to higher coal-fired generation). For a discussion of fuel costs, see "*Operating Expenses*" below.

Operating Expenses

Operating expenses for the three- and six-month periods ended June 30, 2010 increased 11.3% and 9.9% compared to the same periods of 2009. This increase in operating expenses was primarily due to higher fuel costs, higher production expenses and higher depreciation expenses, offset somewhat by a decrease in purchased power costs.

For the three- and six-month periods ended June 30, 2010, total fuel costs increased 23.3% and 19.5% and total generation increased 13.7% and 9.3% compared to the same periods of 2009. Average fuel costs per megawatt-hour increased 8.4% and 9.3% in the three- and six-month periods of 2010 compared to the same periods of 2009. This increase in total fuel costs resulted primarily from higher coal-fired generation at Plant Scherer. Additionally, higher nuclear generation at Plant Hatch contributed to the increase in generation during the second quarter of 2010 as compared to same period of 2009. These increases were offset somewhat by lower generation at the natural gas-fired Chattahoochee energy facility. The increase in average fuel costs during the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009 resulted primarily from a 28.2% or 841,000 megawatt-hour increase in generation at Plant Scherer due to no scheduled outage in 2010 whereas there was a scheduled outage in 2009. The increase in nuclear generation at Plant Hatch was due to a shorter planned outage in 2010 as compared to the planned outage in 2009. Natural gas-fired generation at Chattahoochee decreased 33.9% or 417,000 megawatt-hours for the six-months ended June 30, 2010 as compared to the same period of 2009 primarily due to a longer planned maintenance outage. The average fuel cost per megawatt-hour of coal-fired generation is substantially higher than nuclear generation; thus, the increase in coal-fired generation was the primary contributor to the increase in average fuel costs per megawatt-hour of generation.

Production expenses increased 24.0% and 16.6% for the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. This increase is partly attributable to increased general operations and maintenance expenses at the jointly owned plants (Plants Hatch, Vogtle, Wansley and Scherer) during the three- and six-month periods ended June 30, 2010 and partly due to operations and maintenance expenses for the Hawk Road and Hartwell Energy Facilities incurred in 2010. We acquired these facilities in May and October of 2009, respectively.

Total purchased power costs decreased 46.5% and 39.8% for the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. Purchased megawatt-hours decreased 61.5% and 45.4% for the three- and six-month periods of 2010 compared to the same periods of 2009. The average cost per megawatt-hour of total purchased power increased 39.0% and 10.2% for the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009.

Purchased power costs were as follows (amounts in thousands except for cents per kilowatt-hour):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	**2010**	2009
Capacity costs	**$ 4,045**	$ 11,024	**$ 8,057**	$ 21,707
Energy costs	**14,172**	23,026	**27,568**	37,489
Total	**$ 18,217**	$ 34,050	**$ 35,625**	$ 59,196
Kilowatt-hours of purchased power	**103,505**	268,977	**226,628**	414,945
Cents per kilowatt-hour	**17.60¢**	12.66¢	**15.72¢**	14.27¢

Purchased power capacity costs decreased 63.3% and 62.9% in the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. Purchased power energy costs for the three- and six-month periods ended June 30, 2010 decreased 38.5% and 26.5% compared to the same periods of 2009. The average cost per kilowatt-hour of purchased power energy increased 60.0% and 34.7% for the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. The decrease in purchased power capacity costs is primarily attributable to the Hartwell acquisition. As part of the acquisition, we acquired an existing power purchase agreement we had in place with the former owners of Hartwell. The decrease in purchased power energy costs resulted from (i) a decrease in megawatt-hours acquired under our energy replacement program, which replaces power from our owned generation facilities with lower price spot market purchased power energy, (ii) lower realized losses incurred for natural gas financial contracts utilized for managing exposure to fluctuations in the market prices of natural gas and (iii) no power purchases under the Hartwell power purchase agreement which was acquired as discussed above.

Depreciation and amortization expense increased 11.2% and 15.4% in the three- and six-month periods ended June 30, 2010 as compared to the same periods of 2009. The increase was primarily due to increased depreciation expense for Plants Scherer and Wansley related to capital expenditures for environmental compliance projects. Depreciation expense related to Hawk Road and Hartwell also contributed to the increase.

Other Income

Investment income decreased 12.4% and 5.7% in the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. A decrease in interest earnings on cash and cash equivalents due to lower market interest rates on those investments and a decrease in net activity in decommissioning trust funds were the primary drivers for the overall decrease. The line item investment income includes activity in the decommissioning trust funds which includes investment income/loss and an adjustment to the regulatory asset or liability for timing difference between accretion expenses recognized under accounting for asset retirement obligations versus the expense recovered for rate-making purposes. These decreases were offset somewhat by increased earnings on the Rural Utilities Service Cushion of Credit Account due to higher balances in this account compared to the same periods of 2009.

Interest charges

Interest on long-term debt and capital leases increased by 6.3% and 10.4% in the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009. This increase was primarily due to the issuance in November 2009 of $400 million of taxable fixed rate bonds for the purpose of financing construction of Plant Vogtle Units No. 3 and No. 4.

Allowance for debt funds used during construction increased by 83.1% and 112.3% in the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009 primarily due to construction expenditures for Plant Vogtle Units No. 3 and No. 4.

Amortization of debt discount and expense increased 34.6% and 44.1% in the three- and six-month periods ended June 30, 2010 compared to the same periods of 2009 primarily due to amortization of issuance costs associated with transactions that closed in May and August 2009 to provide supplemental credit enhancement for the Rocky Mountain lease arrangements.

Balance Sheet Analysis as of June 30, 2010

Assets

Cash paid for property additions for the six-month period ended June 30, 2010 totaled $335.1 million. Of this amount, approximately $189 million was for expenditures associated with the construction of new generation facilities, primarily for Plant 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.

Nuclear fuel, which is recorded at amortized cost, increased by a net $24.3 million in the six-month period ended June 30, 2010. The increase was due to a combination of factors, including the timing of expenditures, the costs of uranium and enrichment services and an increase in the nuclear fuel inventory level.

Cash and cash equivalents decreased by $216.1 million in the six-month period ended June 30, 2010 and can be largely attributed to expenditures of approximately $335.1 million for property additions and a net application of $90.4 million of the members' prepayments of their power bills. Other significant uses of cash include principal and interest payments, investment in restricted short-term investments and payments to Georgia Power Company for operation and maintenance costs.

The $8.0 million restricted cash balance at June 30, 2010 consisted of the remaining proceeds obtained from the issuance of clean renewable energy bonds in December 2009. The proceeds from the clean renewable energy bonds are restricted in use for certain qualifying expenditures. The decrease for the six-month period ended June 30, 2010 was due in part to the expenditure of $3.4 million for such qualifying costs. In addition, $10.9 million of restricted cash, the proceeds from a December 2009 bond refinancing, was utilized to payoff the principal of the refinanced pollution control revenue bonds that matured in January 2010.

Restricted short-term investments at June 30, 2010 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 notes 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 "Financial Condition—Capital Requirements and Liquidity and Sources of Capital—*Liquidity*" herein.

Receivables increased by $45.5 million in the six-month period ended June 30, 2010. The December 31, 2009 receivables balance included approximately $20.7 million of credits available to the members for a board approved reduction to 2009 revenue requirements as a result of margins collected in excess of our 2009 target 1.12 margins for interest ratio. The increase in receivables was largely due to these credits being utilized by the members during 2010. The receivable for amounts billed or billable to the members for their monthly power bills also increased by approximately $16.6 million in June 2010 compared to December 2009. This increase was primarily due to higher energy costs in June 2010, which was a result of increased generation. Receivables from Smarr EMC for costs incurred for operation of its facilities also increased by $5.6 million. A $1.9 million increase in the receivable from the members associated with natural gas derivatives also contributed to the overall increase in receivables. For information regarding the natural gas contracts, see Note C of Notes to Unaudited Condensed Financial Statements.

Deferred outage costs increased $8.7 million (net of amortization) during the six-month period ended June 30, 2010 as a result of the deferral of approximately $24.9 million of outage related costs. Plant Hatch Unit No. 1, Plant Vogtle Unit No. 2 and Plant Wansley Unit No. 1 were in refueling and/or major maintenance outages for varying lengths of time during 2010. Deferred outage costs are amortized over each plant's operating cycle.

The $13.7 million increase in the deferred asset associated with retirement obligations in the six-month period ended June 30, 2010 was primarily due to an $18.5 million decrease in the unrealized gains associated with the nuclear decommissioning fund. Consistent with our ratemaking policy, unrealized gains or losses from the nuclear decommissioning fund are deducted from or added to the deferred asset associated with retirement obligations. The decrease in the nuclear decommissioning fund unrealized gains therefore increased the deferred asset by $18.5 million. The deferred asset also increases or decreases to the extent of timing differences between recognized accretion expense associated with nuclear decommissioning and the amounts recovered through decommissioning fund earnings. Nuclear decommissioning accretion and related expenses of approximately $7.5 million and decommissioning fund net earnings of approximately $11.9 million resulted in the deferred charge decreasing by $4.4 million in the six-month period ended June 30, 2010.

Equity and Liabilities

The $127.2 million increase in short-term borrowings was primarily for borrowings to fund construction of Plant Vogtle Units No. 3 and No. 4.

Long-term debt and capital leases due within one year increased $27.5 million as a result of scheduled debt maturities and the consequent reclassification of certain long-term debt.

Accounts payable increased $78.3 million in the six-month period ended June 30, 2010 primarily due to a $60.6 million increase in the payable to Georgia Power for operation, maintenance and capital costs. The increase in the payable to Georgia Power is primarily associated with construction costs for Plant Vogtle Units No. 3 and No. 4. In addition, there was a $13.7 million increase in the payable for natural gas. This increase was due to increased generation at the natural gas fired plants in June 2010 compared with December 2009.

Accrued and withheld taxes decreased $10.0 million in the six-month period ended June 30, 2010 as a result of payments made (when due) for 2009 property taxes, which exceeded the normal monthly property tax accruals.

Member power bill prepayments represent funds received from the members for prepayment of their monthly power bills. At June 30, 2010, $85.8 million of member power bill prepayments was classified as a current liability and $24.4 million of member power bill prepayments was classified as a long-term deferred liability. During the first half of 2010, approximately $49.9 million of prepayments were received from the members and approximately $140.3 million was applied to the members' monthly power bills. The application of member prepayments received in the prior year to the current year's power bills was a significant contributor to the cash outflow from operations. For information regarding the power bill prepayment program, see Note J of Notes to Unaudited Condensed Financial Statements and see "Financial Condition—Capital Requirements and Liquidity and Sources of Capital—*Liquidity*" herein.

Other current liabilities decreased by $3.4 million during the first half of 2010, primarily due to a $3.9 million decrease in accruals for other miscellaneous payables. Accrued payroll charges also decreased by $1.7 million, which was a result of the payout of 2009 performance pay. Partially offsetting this decrease was a $1.9 million increase in the liability associated with natural gas derivatives.

Primarily as a result of incurring approximately $5.4 million of removal costs for the retirement of certain assets, accumulated retirement costs for other obligations decreased by $4.6 million.

Other deferred credits and liabilities increased $14.5 million in the six-month period ended June 30, 2010 partially due to a $6.1 million increase in the regulatory liability established to defer the effects on net margin that result from Hawk Road Energy Facility operations. Also contributing to the increase was a $5.0 million increase in funding received from the members for future debt payments related to the Talbot and Chattahoochee Energy Facilities. During the first half of 2010, funding for the future overhaul of the combustion turbine plants increased by $2.8 million.

Financial Condition

Capital Requirements and Liquidity and Sources of Capital

Future Power Resources

To meet the energy needs of our members, we have embarked on a generation expansion program. In addition to the two acquisitions in 2009 (the 500 megawatt Hawk Road Energy Facility and the 300 megawatt Hartwell Energy Facility), members have subscribed to three projects currently under development, including Plant Vogtle Units No. 3 and No. 4 (our 30% share is 660 megawatts), the 100 megawatt Warren County biomass plant and a 605 megawatt gas-fired combined cycle plant. For a further discussion of the new generation projects under development, see "BUSINESS—OUR POWER SUPPLY RESOURCES—*Future Power Resources*" in our 2009 Form 10-K.

The projected commercial operation date for the Warren County biomass plant was initially 2014. However, we have extended the projected commercial operation date to 2015 due to uncertainties related to proposed emissions standards for industrial boilers, including those for biomass plants, and the availability of related emissions control technologies. We are also considering the potential impact of uncertainties related to regulatory and legislative issues, including whether certain biomass electricity production will (i) qualify under any renewable electricity standard that may be established or (ii) be subject to the U.S. Environmental Protection Agency, or EPA, greenhouse gas regulations. Despite these uncertainties, we continue to move forward with many of the activities associated with the biomass plant, including environmental evaluations, air permitting and other governmental approvals and negotiations with boiler and equipment manufacturers. For further discussion of environmental considerations that may affect the design and construction of this plant, see "*—Environmental Regulations*" below and "BUSINESS—ENVIRONMENTAL AND OTHER REGULATION" in our 2009 Form 10-K.

Capital Expenditures

The table below details our revised forecast of capital expenditures for 2010 through 2012. As reported in our 2009 Form 10-K, our estimated cost to construct the Warren County biomass plant, which assumed a commercial operation date of 2014, was $477 million, including allowance for funds during construction. Based on the factors discussed above, we anticipate the delay in commercial operation will result in less than a 5% increase in the estimated cost of the biomass plant. However, the delay will shift a significant amount of expenditures beyond 2012, the final year reflected in the capital expenditure table in our 2009 Form 10-K. In addition to reflecting revisions to the Warren County biomass plant expenditure schedule, the table also reflects revised capital expenditures for 2010 through 2012 for Vogtle Units No. 3 and No. 4 and the combined cycle plant; although, the overall budgets for each of these two projects remain largely the same.

Capital Expenditures(1)
(dollars in millions)

	2010	2011	2012	Total
Future Generation(2)	$491	$553	$ 784	$1,828
Existing Generation(3)	75	88	95	258
Environmental Compliance(4)	106	182	238	526
Nuclear Fuel	103	102	113	318
General Plant	3	2	2	7
Total	$778	$927	$1,232	$2,937

(1) Includes allowance for funds used during construction.

(2) Construction of Vogtle Units No. 3 & No. 4, the Warren County biomass facility and a 605 megawatt combined cycle facility.

(3) Normal additions and replacements to plant in-service.

(4) Pollution control equipment being installed at Plant Scherer.

In addition to the amounts reflected in the table above, we expect to spend approximately $3.2 billion by 2017 to complete construction of the future generation facilities currently under development. In addition to the deferral of expenditures past 2012, this figure also increased from the amount reported in our 2009 Form 10-K due to the inclusion of amounts inadvertently omitted. For information about our financing plans for these projects, see "*—Financing Activities*."

Our capital expenditures relating to environmental compliance depend in part on implementation of new or existing laws, regulations, judicial decisions, and how we and the other co-owners of coal-fired Plants Scherer and Wansley choose to comply with these regulations once finalized. Regulations adopted by the Georgia Environmental Protection Division specify certain environmental control equipment that must be added to Georgia electric generating units by specific dates, including Plants Scherer and Wansley. The last of the Plant Wansley projects was completed and placed in service in 2009. In addition to the environmental compliance expenditures listed in the table above, we forecast expenditures of approximately $100 million to complete the projects underway at Plant Scherer by 2014. The Plant Scherer projects will require extended unit outages in 2011, although not during peak energy use periods. As the construction environment, including the changing cost of materials and labor, continues to evolve, the estimated cost to install these retrofits continues to be refined. The forecasted expenditures are based on information available to us on the date of this Quarterly Report on Form 10-Q; however, there can be no assurance that the cost of compliance with these regulations will not be higher, nor that future regulations will not require additional reductions in emissions or earlier compliance. See Note G of the Notes to Unaudited Condensed Financial Statements for more information on environmental compliance matters.

Actual expenditures may vary from the estimates because of factors such as changes in business conditions, design changes and rework required by regulatory bodies, delays in obtaining necessary regulatory approvals, construction delays, changing environmental requirements, and changes in cost of capital, equipment, material and labor. Large construction projects such as the future generation and environmental compliance projects entail certain risks, as described in "Item 1A—RISK FACTORS" in our 2009 Form 10-K.

Environmental Regulations

In June 2010, EPA proposed several national emission standards for hazardous air pollutants for commercial, industrial and institutional boilers, which would tighten emission limits for various pollutants regulated under section 112 of the Clear Air Act. Also in June 2010, EPA issued a final rule tightening its national ambient air quality standard for sulfur dioxide, replacing the annual and 24-hour standards with a new, more stringent, 1-hour standard. On August 2, 2010, EPA proposed a new rule, known as the Transport Rule, to replace the Clean Air Act Interstate Rule (CAIR). Similar to the CAIR, this new Transport Rule would regulate emissions of sulfur dioxide and nitrogen oxides by certain Eastern and Midwestern states, including Georgia, deemed to be contributing significantly to nonattainment of the national ambient air quality standards for fine particulates and ozone. The final rule revising the sulfur dioxide standard will likely be challenged, while the proposed rules could undergo substantial revision prior to finalization (at which time they might be challenged). We cannot predict at this time whether any of these developments will ultimately result in the further regulation of emissions from our existing or future fossil fuel-fired or biomass-fired power plants, or the effects of any such regulation, including any resulting capital requirements.

EPA also recently issued three rules that together determine when new or modified stationary sources of greenhouse gases (GHGs) (which include carbon dioxide) become regulated under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. These rules establish a three-step schedule for application of PSD and Title V to stationary sources. The first two steps of regulation begin January 2, 2011 and July 1, 2011 for larger sources of GHGs, while a possible third step for smaller GHG sources may begin April 30, 2016. Also, EPA has stated its intention to issue a revised New Source Performance Standard for steam generating units operated by electric utilities (and other industrial and commercial facilities) in 2010. Several of the final rules discussed above are subject to numerous petitions for review, and challenges to the remaining rules may be brought in the near future. We cannot predict at this time whether these developments will ultimately result in the regulation of GHG emissions from our existing or future fossil fuel-fired or biomass-fired power plants, or the effects of any such regulation, including capital requirements.

In addition, the possibility of new federal legislation that could lead to regulation of emissions of GHGs from stationary sources continues. Legislation is pending in Congress that includes GHG emissions caps and a national renewable electricity standard, which would initially apply to two of our members. However, recent developments indicate that Congress will not be moving forward with climate legislation that would include GHG emissions caps or a renewable electricity standard at this time. We cannot predict, however, whether legislative action will be taken in the future that would regulate GHG emissions from our existing or future fossil fuel-fired power plants or impose a renewable electricity standard on our members.

Liquidity

At June 30, 2010, we had $963 million of unrestricted available liquidity to meet our short-term cash needs and liquidity requirements. This amount included $363 million in cash and cash equivalents and $600 million of unused and available committed short-term credit arrangements. As discussed above, cash and cash equivalents decreased by approximately $216 million during the six-month period ended June 30, 2010 mainly due to expenditures for property additions and the application of member power bill prepayments to power bills.

Our short-term credit facilities are shown in the table below. We expect to renew these short-term credit facilities, as needed, prior to their respective expiration dates.

Committed Short-Term Credit Facilities

	Authorized Amount	Available 6/30/2010	Available 8/13/2010	Expiration Date
	(dollars in millions)			
Unsecured Facilities:				
Commercial Paper Backup Line of Credit	$ 475	$ 64(1)	$ 1(1)	July 2012
CoBank Line of Credit	50	50	34	December 2010
CFC Line of Credit	50	50	50	October 2011
JPMorgan Chase Line of Credit	150	36(2)	36(2)	December 2012
Secured facilities:				
CoBank Line of Credit	150	150	150	November 2012
CFC Line of Credit	250	250	250	December 2013
Total	**$1,125**	**$600**	**$521**	

(1) The portion of this facility that is unavailable is supporting commercial paper we have issued.

(2) $114 million of this facility is currently utilized as letter of credit support for variable rate pollution control revenue bonds.

We have used or plan to use commercial paper and short-term credit facilities to provide temporary funding for (i) payments related to construction of Plant Vogtle Units No. 3 and No. 4, (ii) acquisitions of Hawk Road and Hartwell, and (iii) initial engineering and design work related to the Warren County biomass plant and the combined cycle plant, as well as to provide credit support for variable rate pollution control revenue bonds. For a discussion of our plans regarding permanent financing of these generation facilities, see "*—Financing Activities.*"

In order to further enhance our liquidity position during the peak years of new generation construction, we currently anticipate a restructuring and related upsizing of certain of our short-term credit facilities, including the commercial paper backup credit facility, sometime in 2011. The exact timing, size and term of the restructured credit facilities will be influenced by many factors, including the ultimate size of the construction program, the timing of permanent financing for new generation facilities and overall market conditions.

Under the commercial paper program, we are authorized to issue commercial paper in amounts that do not exceed the amount of any committed backup lines of credit in place, thereby providing 100% dedicated backup support for any paper outstanding. We periodically assesses our needs in order to determine the appropriate amount of commercial paper backup to maintain and currently have in place a $475 million committed backup credit facility provided by eight participant banks, with Bank of America serving as administrative agent for this facility.

Along with the lines of credit from CoBank, the National Rural Utilities Cooperative Finance Corporation (CFC) and JPMorgan Chase Bank, funds may also be advanced under the backup line of credit supporting commercial paper for general working capital purposes. In addition, under certain of our committed credit facilities we have the ability to issue letters of credit totaling $450 million in the aggregate, of which $336 million remained available at June 30, 2010. However, any amounts related to issued letters of credit will reduce the amount available to draw as working capital under those facilities. Also, due to the requirement to have 100% dedicated backup for any commercial paper outstanding, any amounts drawn under the commercial paper backup 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 indenture.

Several of our line of credit facilities contain a similar financial covenant that requires us to maintain minimum levels of patronage capital. At June 30, 2010, the required minimum level was $545 million and our actual patronage capital was $584 million. An additional covenant contained in several of our credit facilities limits our secured indebtedness to $8.5 billion and our unsecured indebtedness to $4.0 billion. At June 30, 2010, we had approximately $4.5 billion of secured indebtedness outstanding and $521 million of unsecured indebtedness outstanding.

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, 2010, the balance of member prepayments received but not yet credited to their power bills was $110 million, which represented prepayments from sixteen members participating in the program. We began applying the prepayments against participating members' power bills in 2009 and will continue doing so through May 2015, with the majority scheduled to be applied in 2010. For more information regarding the power bill prepayment program, see Note J of Notes to Unaudited Condensed Financial Statements.

At June 30, 2010, current assets included $123 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. The amount on deposit in this account is less than one year's debt service payments owed to the Rural Utilities Service and Federal Financing Bank. Our decisions regarding how to apply the funds are guided by the interest rate environment and our anticipated liquidity needs.

Financing Activities

Bond Financings. In the fourth quarter of 2010, we anticipate issuing approximately $400 million of taxable first mortgage bonds for the purpose of funding a portion of the cost of constructing Plant Vogtle Units No. 3 and No. 4. A portion of the proceeds will be used to repay outstanding short-term borrowings in connection with payments previously made for construction of this facility. The first mortgage bonds will be secured under our indenture.

We also anticipate a tax-exempt issuance of pollution control revenue bonds in the fourth quarter of 2010 in the amount of approximately $12 million in connection with the refinancing of a like amount of outstanding pollution control revenue bonds that are scheduled to mature on January 1, 2011. This tax-exempt issuance may be increased to include a modest amount of new tax-exempt debt related to pollution control equipment being installed at Plant Scherer, but the timing and exact amount of this new debt, if any, is uncertain at this time. We expect that this tax-exempt debt will be secured under our indenture.

Rural Utilities Service-Guaranteed Loans. We currently have two Rural Utilities Service-guaranteed loans, funded through the Federal Financing Bank, totaling $534 million that are in the process of being drawn down, with $284 million remaining to be advanced. We have one general and environmental improvements loan for approximately $310 million that was approved in July 2009 that is expected to close in the third quarter of 2010. We also have five loan applications, totaling approximately $1.72 billion, pending with the Rural Utilities Service, including two applications related to the Hawk Road and Hartwell acquisitions (action anticipated in the third quarter of 2010), a loan application related to the Warren County biomass plant (action anticipated in 2011), a loan application related to general improvements at existing generation facilities (action anticipated later in 2010 or in 2011) and a loan application related to the gas-fired combined cycle plant (action not anticipated prior to 2012). However, the President's budget proposal for fiscal year 2011 (which begins October 1, 2010) would prohibit Rural Utilities Service funding for (i) improvements to existing fossil-fueled generation facilities unless the improvements are related to carbon-capture projects, and (ii) construction of new fossil-fueled generation facilities. Nonetheless, should members subscribe to any additional gas-fired combined cycle or combustion turbine facilities, we anticipate filing loan applications for those facilities as well, to the extent Rural Utilities Service regulations in place at that time allow us to do so. See "BUSINESS—OGLETHORPE POWER CORPORATION—Relationship with the Rural Utilities Service" in our 2009 Form 10-K for a more detailed discussion of the Rural Utilities Service's current position relating to funding of generation facilities.

All of the approved Rural Utilities Service loans will be funded through the Federal Financing Bank and guaranteed by the Rural Utilities Service, and the debt will be secured under our indenture.

Department of Energy-Guaranteed Loans. We have signed a conditional term sheet with the Department of Energy that sets forth the general terms of a loan and related loan guarantee that would fund approximately 70% of the estimated $4.2 billion cost to construct our 30% undivided share in two new nuclear units proposed at Plant Vogtle, not to exceed $3.057 billion. The loan structure would entail a loan funded through the Federal Financing Bank carrying a federal loan guarantee provided by the Department of Energy, with the debt secured under our 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 Plant 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.

For any Plant Vogtle project costs not funded by the Department of Energy, we plan to issue taxable bonds and tax-exempt bonds for any equipment that may qualify for tax-exempt financing. Of the $1.2 billion of estimated project costs that are not expected to be financed by the Department of Energy, if the Department of Energy issues the loan guarantee to us, we have already financed $400 million through the issuance of taxable first mortgage bonds in November 2009, and we have plans to issue an additional approximately $400 million of taxable first mortgage bonds for this purpose in the fourth quarter of 2010.

For more detailed information regarding our financing plans, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities*" in our 2009 Form 10-K.

Our Indenture

In May 2010, we became the direct owner of the Hawk Road Energy Facility and the Hartwell Energy Facility, which were formerly held by two of our wholly owned subsidiaries. These facilities are now included in the mortgaged property and therefore subject to the lien of our indenture. For further discussion, see "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Financial Condition—*Financing Activities—Our Indenture*" in our 2009 Form 10-K.

Newly Adopted or Issued Accounting Standards

For a discussion of "Fair Value Measurements and Disclosures" see Note E of Notes to Unaudited Condensed Financial Statements herein.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Our market risks have not changed materially from the risks reported in our 2009 Form 10-K.

Item 4. Controls and Procedures

As of June 30, 2010, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended. Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective.

There have been no changes in our internal control over financial reporting or other factors that occurred during the quarter ended June 30, 2010 that have materially affected, or are reasonably likely to 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 Annual Report on Form 10-K for the fiscal year ended December 31, 2009.

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
4.1	Fifty-Fourth Supplemental Indenture, dated as of May 21, 2010, made by Oglethorpe to U.S. Bank National Association, as trustee, confirming the lien of the Indenture with respect to certain After-Acquired Property (relating to the Hawk Road and Hartwell Energy Facilities).
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).

SIGNATURES

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

		Oglethorpe Power Corporation (An Electric Membership Corporation)
Date: August 13, 2010	By:	/s/ Thomas A. Smith
		Thomas A. Smith President and Chief Executive Officer
Date: August 13, 2010		/s/ Elizabeth B. Higgins
		Elizabeth B. Higgins Executive Vice President and Chief Financial Officer (Principal Financial Officer)