
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549**

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2007

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 number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE
(Exact Name of Registrant as Specified in Its Charter)

VIRGINIA
(State or Other Jurisdiction of
Incorporation or Organization)

23-7048405
(I.R.S. Employer
Identification No.)

4201 Dominion Boulevard, Glen Allen, Virginia
(Address of Principal Executive Offices)

23060
(Zip Code)

(804) 747-0592

(Registrant's Telephone Number, Including Area Code)

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 is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Larger accelerated filer Accelerated filer Non-accelerated filer

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes No

The Registrant is a membership corporation and has no authorized or outstanding equity securities

OLD DOMINION ELECTRIC COOPERATIVE

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OLD DOMINION ELECTRIC COOPERATIVE
PART 1. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
CONDENSED CONSOLIDATED BALANCE SHEETS

	<u>September 30,</u> 2007	<u>December 31,</u> 2006
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
In service	\$ 1,524,067	\$ 1,527,672
Less accumulated depreciation	(538,036)	(509,306)
	<u>986,031</u>	<u>1,018,366</u>
Nuclear fuel, at amortized cost	9,933	8,381
Construction work in progress	23,231	20,342
Net Electric Plant	<u>1,019,195</u>	<u>1,047,089</u>
Investments:		
Nuclear decommissioning trust	96,302	91,050
Lease deposits	178,183	171,585
Other	96,172	24,321
Total Investments	<u>370,657</u>	<u>286,956</u>
Current Assets:		
Cash and cash equivalents	105,064	52,018
Accounts receivable	5,915	4,071
Accounts receivable-deposits	-	23,600
Accounts receivable-members	92,147	94,136
Fuel, materials and supplies	30,642	30,585
Deferred energy	34,771	14,914
Prepayments	2,237	4,035
Total Current Assets	<u>270,776</u>	<u>223,359</u>
Deferred Charges:		
Regulatory assets	33,693	49,738
Other	17,758	20,267
Total Deferred Charges	<u>51,451</u>	<u>70,005</u>
Total Assets	<u>\$ 1,712,079</u>	<u>\$ 1,627,409</u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 304,270	\$ 293,077
Non-controlling interest	11,066	10,993
Long-term debt	815,837	813,264
Total Capitalization	<u>1,131,173</u>	<u>1,117,334</u>
Current Liabilities:		
Long-term debt due within one year	22,917	22,917
Accounts payable	108,540	87,844
Accounts payable-members	64,160	48,220
Accrued expenses	60,433	35,767
Total Current Liabilities	<u>256,050</u>	<u>194,748</u>
Deferred Credits and Other Liabilities:		
Asset retirement obligation	58,010	55,812
Obligations under long-term leases	180,661	174,205
Regulatory liabilities	54,478	51,497
Other	31,707	33,813
Total Deferred Credits and Other Liabilities	<u>324,856</u>	<u>315,327</u>
Commitments and Contingencies		
Total Capitalization and Liabilities	<u>\$ 1,712,079</u>	<u>\$ 1,627,409</u>

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

OLD DOMINION ELECTRIC COOPERATIVE

**CONDENSED CONSOLIDATED STATEMENTS OF REVENUES,
EXPENSES AND PATRONAGE CAPITAL (UNAUDITED)**

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Operating Revenues	\$ 262,362	\$ 221,231	\$ 717,691	\$ 610,644
Operating Expenses:				
Fuel	57,649	65,636	120,166	120,936
Purchased power	167,647	109,675	473,103	359,796
Deferred energy	(12,951)	339	(19,857)	(8,395)
Operations and maintenance	11,235	8,459	34,172	26,097
Administrative and general	8,811	7,530	25,424	24,879
Depreciation, amortization and decommissioning	9,365	9,628	28,189	28,922
Amortization of regulatory asset/(liability), net	624	444	1,517	1,137
Accretion of asset retirement obligations	732	651	2,197	1,953
Taxes other than income taxes	1,923	2,245	5,557	5,358
Total Operating Expenses	<u>245,035</u>	<u>204,607</u>	<u>670,468</u>	<u>560,683</u>
Operating Margin	<u>17,327</u>	<u>16,624</u>	<u>47,223</u>	<u>49,961</u>
Other Expense, net	(40)	(16)	(101)	(84)
Investment Income	3,886	2,243	10,519	6,413
Interest Charges, net	<u>(15,496)</u>	<u>(15,306)</u>	<u>(45,783)</u>	<u>(45,376)</u>
Net Margin Before Income Taxes and Non-Controlling Interest	<u>5,677</u>	<u>3,545</u>	<u>11,858</u>	<u>10,914</u>
Income Taxes	(132)	(182)	(157)	(720)
Non-Controlling Interest	<u>(442)</u>	<u>(274)</u>	<u>(508)</u>	<u>(1,080)</u>
Net Margin	<u>5,103</u>	<u>3,089</u>	<u>11,193</u>	<u>9,114</u>
Patronage Capital - Beginning of Period	<u>299,167</u>	<u>277,858</u>	<u>293,077</u>	<u>271,833</u>
Patronage Capital - End of Period	<u>\$ 304,270</u>	<u>\$ 280,947</u>	<u>\$ 304,270</u>	<u>\$ 280,947</u>

OLD DOMINION ELECTRIC COOPERATIVE

**CONDENSED CONSOLIDATED STATEMENTS
OF COMPREHENSIVE INCOME (UNAUDITED)**

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Net Margin	\$ 5,103	\$ 3,089	\$ 11,193	\$ 9,114
Other Comprehensive Income:				
Unrealized loss on derivative contracts ⁽¹⁾	-	(467)	(435)	(14,307)
Other Comprehensive Income Before Non-Controlling Interest	-	2,622	10,758	(5,193)
Less: Non-controlling interest in comprehensive income	-	467	435	14,307
Comprehensive Income	<u>\$ 5,103</u>	<u>\$ 3,089</u>	<u>\$ 11,193</u>	<u>\$ 9,114</u>

⁽¹⁾ Unrealized loss on derivative contracts net of taxes of \$0.3 million for the nine months ended September 30, 2007. Unrealized loss on derivative contracts net of taxes of \$0.3 million and \$9.1 million for the three and nine months ended September 30, 2006, respectively.

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

**Nine Months Ended
September 30,**

	2007	2006
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(in thousands)

Operating Activities:		
Net Margin	\$ 11,193	\$ 9,114
Adjustments to reconcile net margins to net cash provided by (used for) operating activities:		
Depreciation, amortization and decommissioning	28,189	28,922
Other non-cash charges	8,997	8,852
Non-controlling interest	508	1,080
Amortization of lease obligations	8,684	8,218
Interest on lease deposits	(8,460)	(7,965)
Change in current assets	25,486	30,360
Change in deferred energy	(19,857)	(8,395)
Change in current liabilities	67,279	(29,811)
Change in regulatory assets and liabilities	17,499	(56,090)
Deferred charges and credits	1,763	12,052
Net Cash Provided by/(Used for) Operating Activities	141,281	(3,663)
Financing Activities:		
Obligations under long-term leases	(366)	(595)
Net Cash Used for Financing Activities	(366)	(595)
Investing Activities:		
Purchases of available for sale securities	(266,147)	(57,650)
Proceeds from sale of available for sale securities	176,779	21,975
Decrease (Increase) in other investments	13,793	(2,800)
Electric plant additions	(15,294)	(9,512)
Settlement of litigation	3,000	-
Net Cash (Used for)/Provided by Investing Activities	(87,869)	(47,987)
Net Change in Cash and Cash Equivalents	53,046	(52,245)
Cash and Cash Equivalents - Beginning of Period	52,018	98,633
Cash and Cash Equivalents - End of Period	\$ 105,064	\$ 46,388

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. In the opinion of our management, the accompanying unaudited condensed consolidated financial statements contain all adjustments, which include only normal recurring adjustments, necessary for a fair statement of our consolidated financial position as of September 30, 2007, and our consolidated results of operations, comprehensive income, and cash flows for the three and nine months ended September 30, 2007 and 2006. The consolidated results of operations for the three and nine months ended September 30, 2007, are not necessarily indicative of the results to be expected for the entire year. These financial statements should be read in conjunction with the financial statements and notes thereto included in our 2006 Annual Report on Form 10-K filed with the Securities and Exchange Commission.
2. *Presentation.* The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative (“ODEC” or “we” or “our”) and TEC Trading, Inc. (“TEC”). We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are twelve customer-owned electric distribution cooperatives engaged in the retail sale of power to member consumers located in Virginia, Delaware, Maryland, and parts of West Virginia. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC.

In accordance with Financial Accounting Standards Board (“FASB”) Interpretation No. 46R, “Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51” (the “Interpretation”), TEC is considered a variable interest entity for which we are the primary beneficiary. We have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the net assets consolidated were \$11.1 million and \$11.0 million at September 30, 2007, and December 31, 2006, respectively. As TEC is 100% owned by our twelve member distribution cooperatives, its equity is presented as a non-controlling interest in our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities is recorded using the equity method of accounting.

Our rates are not regulated by the respective states’ public service commissions, but are set periodically by a formula that was accepted for filing by the Federal Energy Regulatory Commission (“FERC”) on December 23, 2003. An amendment to the formula was accepted for filing by FERC on February 19, 2005, subject to the outcome of our other pending FERC proceedings.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with accounting principles generally accepted in the United States (“GAAP”), the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes.

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates.

3. *Financial Instruments (including Derivatives).* Financial instruments included in the decommissioning fund are classified as available for sale, and accordingly, are carried at fair value. Unrealized gains and losses on investments held in the decommissioning fund are deferred as a regulatory liability and a regulatory asset until realized.

Our investments in marketable securities, which are actively managed, are classified as available for sale and are recorded at fair value. Unrealized gains or losses on these investments, if material, are reflected as a component of capitalization. Investments in debt securities that we have the positive intent and ability to hold to maturity are classified as held to maturity and are recorded at amortized cost. Other investments are recorded at cost, which approximates market value.

We primarily purchase power under both long-term and short-term forward physical delivery contracts to supply power to our member distribution cooperatives under “all requirements” wholesale power contracts. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of the forward purchase derivative contracts qualify for the normal purchases/normal sales exception under Statement of Financial Accounting Standards (“SFAS”) No. 133 “Accounting for Derivative Instruments and Hedging Activities.” As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the forward physical delivery contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for the operation of our combustion turbine facilities and to hedge certain forward power purchase

agreements that use natural gas as a basis for determining the price of power. These derivatives do not qualify for the normal purchase/normal sales exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we may elect cash flow hedge accounting in accordance with SFAS No. 133. Accordingly, gains and losses on derivative contracts are deferred into Other Comprehensive Income until the hedged underlying transaction occurs or is no longer likely to occur. For derivative contracts where hedge accounting is not utilized, or for which ineffectiveness exists, we defer all remaining gains and losses on a net basis as a regulatory asset or liability in accordance with SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation." These amounts are subsequently reclassified as purchased power or fuel expense in our Consolidated Statements of Revenues, Expenses and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported on the Consolidated Balance Sheet at fair value. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value. There was no hedge ineffectiveness for the three and nine months ended September 30, 2007. Hedge ineffectiveness was immaterial for the three and nine month ended September 30, 2006.

We are exposed to credit risk in our business operations. We have a Credit Risk Policy that establishes the basis for determining counterparty credit standards and processes to determine credit limits. Our risk management committee monitors credit exposure on a regular basis. Formal counterparty credit reviews are performed at least annually and informal reviews are performed on an ongoing basis

4. *Commitments and Contingencies.*

Norfolk Southern

In April 1989, we entered into a coal transportation agreement with Norfolk Southern Railway Company ("Norfolk Southern") for delivery of coal to the Clover Power Station ("Clover"). The agreement, which was later assigned to Virginia Electric & Power Company ("Virginia Power") as operator of Clover, had an initial 20-year term and provides that the amounts payable for coal transportation services are subject to adjustment based on a reference index. In October 2003, Norfolk Southern claimed that it had been using an incorrect reference index to calculate amounts due to it since the inception of the agreement, and that it would begin to escalate prices for these services in the future based on an alternate reference index. On November 26, 2003, together with Virginia Power, we filed suit against Norfolk Southern in the Circuit Court of Halifax County, Virginia, seeking an order to clarify the price escalation provisions in the coal transportation agreement. In its reply to our suit, Norfolk Southern filed a counter-claim and sought (1) recovery from Virginia Power and us for additional amounts resulting from its use of the alternate reference index since December 1, 2003, and (2) an order requiring the parties to calculate the amounts Norfolk Southern claims it was underpaid since the inception of the agreement by using the alternate reference index.

On December 22, 2004, the court found in favor of Norfolk Southern on the issue of ambiguity and held that the price escalation provisions in the agreement were clear and unambiguous. The court later denied Virginia Power's and our motion to file an amended complaint based on additional evidence that was not considered by the court in the original proceedings. The court permitted Virginia Power and us to file an amended answer to Norfolk Southern's counter-claims and our amended answer was filed on March 4, 2005.

On September 1, 2006, the court granted Norfolk Southern's request to substantially dispose of the issues in the case. On September 23, 2006, we, along with Virginia Power, appealed the court's order to the Supreme Court of Virginia. On December 13, 2006, Norfolk Southern filed a motion to dismiss for lack of jurisdiction, contending that we and Virginia Power failed to timely appeal. On April 4, 2007, we, along with Virginia Power, presented our arguments to a panel of three justices as to why the petition for appeal should be granted.

On May 11, 2007, the Supreme Court of Virginia dismissed Norfolk Southern's motion to dismiss for lack of jurisdiction and dismissed our petition for appeal because there is not a final appealable order. The case was returned to the Circuit Court of Halifax County, Virginia. On June 11, 2007, we, along with Virginia Power, filed a motion to vacate the order and schedule a status conference. On June 26, 2007, Norfolk Southern filed a motion for a status conference and a brief in opposition to our motion to vacate the order. We are currently awaiting the court's decision.

We recorded a liability related to the Norfolk Southern dispute and created a related regulatory asset for prior charges. The regulatory asset was amortized over 21 months (April 1, 2005 through December 31, 2006) and was fully amortized and collected through rates as of December 31, 2006. The current period charges are being collected through rates. If it is ultimately determined that we owe any such amounts to Norfolk Southern, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates charged to our member distribution cooperatives.

Ragnar Benson

In December 2002, we entered into a contract with Ragnar Benson, Inc. (“RBI”) for engineering, procurement and construction services relating to the construction of our Marsh Run combustion turbine facility. On December 23, 2004, we terminated the contract with RBI for default and filed suit in the U.S. District Court for the Eastern District of Virginia, Richmond Division, against RBI. On June 13, 2005, we executed an agreement with RBI’s surety, Seaboard Surety Company (“Seaboard”), under which it assumed all responsibilities for the final completion of the Marsh Run facility in accordance with the terms of the original agreement with RBI. RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for reorganization on October 14, 2005. Because RBI filed for reorganization during the legal proceeding, we served a lawsuit against Seaboard on February 10, 2006, in order to enforce the eventual outcome of the suit with RBI. On August 23, 2007, we settled our legal disputes with Seaboard. In full settlement of our legal disputes with Seaboard, we received a payment of \$3.0 million from Seaboard and we were released of any and all remaining payment obligations. At the time of the settlement we had a \$5.7 million liability recorded which was reversed based on the terms of the settlement. The \$8.7 million impact of the settlement resulted in a reduction of the cost of our Marsh Run facility. The terms of our agreement provided for the assignment by ODEC to Seaboard of all of ODEC’s rights and claims against RBI in the current reorganization proceedings including the judgment obtained against RBI, and Seaboard and ODEC each released the other from any and all claims arising out of or related to the Marsh Run Project.

5. *New Accounting Pronouncements.*

We adopted the provisions of the Financial Accounting Standards Board (“FASB”) Interpretation No. 48, “Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109” (“FIN 48”) on January 1, 2007. This interpretation requires that income tax positions recognized in an entity’s tax returns have a more-likely-than-not chance of being sustained prior to recording the related tax benefit in the financial statements. There was no impact on our financial statements as a result of the adoption of FIN 48.

In September 2006, the FASB issued Statement No. 157, “Fair Value Measurements” (“SFAS No. 157”). SFAS No. 157 clarifies that the term fair value is intended to mean a market-based measure, not an entity-specific measure and gives the highest priority to quoted prices in active markets in determining fair value. SFAS No. 157 requires disclosures about the extent to which companies measure assets and liabilities at fair value, the methods and assumptions used to measure fair value, and the effect of fair value measures on earnings. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact that SFAS No. 157 may have on our financial statements.

6. *Equity Contribution.*

As approved by our board of directors on July 23, 2007, our net margins include \$2.0 million of equity contribution.

7. *Subsequent Event.*

On October 10, 2007, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 1.7%, effective October 1, 2007. This increase was implemented due to continued increases in our energy costs and to collect a portion of our deferred energy balance. On October 10, 2007 our Board of Directors also approved the refund of \$11.0 million related to our margin stabilization plan, which will be refunded during the fourth quarter of 2007.

OLD DOMINION ELECTRIC COOPERATIVE

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward-Looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors that could cause actual results to differ materially from those expressed in the forward-looking statements. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, increased competition in the electric utility industry, changes in our tax status, demand for energy, federal and state legislative and regulatory actions, and legal and administrative proceedings, changes in and compliance with environmental laws and policies, weather conditions, the cost of commodities used in our industry, and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward-looking statements as a result of these and other factors. Any forward-looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Critical Accounting Policies

As of September 30, 2007, there have been no significant changes in our critical accounting policies as disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2006. The policies included the accounting for rate regulation, deferred energy, asset retirement obligations, derivative contracts and our margin stabilization plan.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative ("ODEC" or "we" or "our") and TEC Trading, Inc. ("TEC"). See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

Overview

ODEC is a not-for-profit power supply cooperative owned entirely by its twelve member distribution cooperatives and a thirteenth member, TEC. We supply our member distribution cooperatives' power requirements, consisting of capacity requirements and energy requirements through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases.

Our financial results for the three and nine months ended September 30, 2007, were impacted by higher energy rates, the availability of our generation facilities, and changes in the fair value of our derivatives. Revenues were higher due to increased sales volume and higher energy rates, which were implemented in October of 2006 and April of 2007 to collect previously incurred but not collected costs and to provide for the collection of future anticipated costs. During the three months ended September 30, 2007, North Anna Power Station ("North Anna") Unit 1 was off-line for a scheduled refueling and maintenance outage. During the nine months ended September 30, 2007, both units at the Clover Power Station ("Clover") were off-line for scheduled maintenance outages and both units at North Anna were off-line for scheduled refueling and maintenance outages. These outages resulted in increased purchased power expense as well as operations and maintenance expenses. Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. The fair value of our natural gas futures increased resulting in changes to our regulatory assets and liabilities which increased cash provided by operating activities.

We have a Margin Stabilization Plan that allows us to review our actual capacity-related costs of service and capacity revenue and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formula rate allows us to recover and refund amounts under the Margin Stabilization Plan. Each quarter we adjust revenues and accounts payable—members or accounts receivable, as appropriate, to reflect these adjustments. During the three months ended September 30, 2007, we refunded \$6.0 million to our member distribution cooperatives related to our margin stabilization plan as approved by our board of directors on July 23, 2007.

Results of Operations

Operating Revenues

Our power sales are comprised of two power products – energy and capacity (also referred to as demand). Energy is the physical electricity delivered through transmission and distribution facilities to customers. We must have sufficient committed energy available to us for delivery to our member distribution cooperatives to meet their maximum energy needs at any time, with limited exceptions. This committed available energy at any time is referred to as capacity.

The rates we charge our member distribution cooperatives for sales of energy and capacity are determined by a formulary rate accepted by the Federal Energy Regulatory Commission (“FERC”), which is intended to permit collection of revenues which will equal the sum of:

- all of our costs and expenses;
- 20% of our total interest charges; and
- additional equity contributions approved by our board of directors.

The formulary rate has three main components: a demand rate, a base energy rate and a fuel factor adjustment rate. The formulary rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval.

Energy costs, which are primarily variable costs, such as nuclear, coal and natural gas fuel costs and the energy costs under our power purchase contracts with third parties, are recovered through two separate energy rates, the base energy rate and the fuel factor adjustment rate. The base energy rate is a fixed rate that requires FERC approval prior to adjustment. However, to the extent the base energy rate over- or under-collects all of our energy costs, we refund or collect the difference through a fuel factor adjustment rate. We review our energy costs at least every six months to determine whether the base energy rate and the current fuel factor adjustment rate together are adequately recovering our actual and anticipated energy costs, and revise the fuel factor adjustment rate accordingly. Since the fuel factor adjustment rate can be revised without FERC approval, we can effectively change our total energy rate to recover all of our energy costs without seeking the approval of FERC.

Capacity costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under our power purchase contracts with third parties, transmission costs, and our margin requirements and additional amounts approved by our board of directors are recovered through our demand rate. The formulary rate allows us to change the actual demand rate we charge as our capacity-related costs change, without seeking FERC approval, with the exception of decommissioning cost, which is a fixed number in the formulary rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, future depreciation studies are to be filed with FERC for their approval if they would result in a change in our depreciation rates. Our demand rate is revised automatically to recover the costs contained in our budget and any revisions made by our board of directors to our budget.

Our operating revenues are derived from power sales to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the three and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Revenues from sales to:				
Member distribution cooperatives	\$ 237,855	\$ 201,620	\$ 645,910	\$ 550,217
Non-members	24,507	19,611	71,781	60,427
Total revenues	<u>\$ 262,362</u>	<u>\$ 221,231</u>	<u>\$ 717,691</u>	<u>\$ 610,644</u>

Our energy sales in megawatt hours (“MWh”) to our member distribution cooperatives and non-members for the three months and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30.	
	2007	2006	2007	2006
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	3,256,837	3,122,086	9,001,847	8,366,995
Non-members	443,453	290,740	1,377,592	1,049,175
Total energy sales	<u>3,700,290</u>	<u>3,412,826</u>	<u>10,379,439</u>	<u>9,416,170</u>

Sales to Member Distribution Cooperatives. Revenues from sales to our member distribution cooperatives are a function of our formulary rate for sales of power to our member distribution cooperatives and our member distribution cooperatives’ consumers’ requirements for power. Operating revenues on our Condensed Consolidated Statements of Revenues, Expenses and Patronage Capital reflect the actual capacity-related costs we incurred plus the energy costs that we collected during the period. Estimated capacity-related costs are collected during the period through the demand component of our formulary rate. Under our formulary rate, we make adjustments for the refund or recovery of amounts under our Margin Stabilization Plan. We adjust demand revenues and accounts payable—members or accounts receivable—members each quarter to reflect these adjustments. During the three months ended September 30, 2007, we refunded \$6.0 million to our member distribution cooperatives related to our margin stabilization plan as approved by our board of directors on July 23, 2007. See “Critical Accounting Policies—Margin Stabilization Plan” in Part II, Item 7 of our Annual Report on Form 10-K for the fiscal year ended December 31, 2006, for a discussion of our Margin Stabilization Plan.

Revenues from sales to our member distribution cooperatives by formulary rate component and average costs to our member distribution cooperatives in MWh for the three and nine months ended September 30, 2007 and 2006 were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30.	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Revenues from sales to member distribution cooperatives:				
Base energy revenues	\$ 58,459	\$ 56,120	\$161,959	\$150,480
Fuel factor adjustment revenues	115,835	92,109	308,784	232,707
Total energy revenues	<u>174,294</u>	<u>148,229</u>	<u>470,743</u>	<u>383,187</u>
Demand (capacity) revenues	63,561	53,391	175,167	167,030
Total revenues from sales to member distribution cooperatives	<u>\$237,855</u>	<u>\$201,620</u>	<u>\$645,910</u>	<u>\$550,217</u>
Average costs to member distribution cooperatives (per MWh)	\$ 73.03	\$ 64.58	\$ 71.75	\$ 65.76

Growth in the number of consumers and growth in consumers’ requirements for power significantly affect our member distribution cooperatives’ requirements for power. Factors affecting our member distribution cooperatives’ consumers’ requirements for power include the amount, size, and usage of electronics and machinery and the expansion of operations among their commercial and industrial customers. Weather also affects the requirement for electricity. Relatively higher or lower temperatures tend to increase the requirement for energy to use air conditioning and heating systems. Mild weather generally reduces the requirement because air conditioning and heating systems are operated less.

Three and Nine months Ended September 30, 2007 compared to Three and Nine months ended September 30, 2006:

Total revenues from sales to our member distribution cooperatives for the three and nine months ended September 30, 2007, increased \$36.2 million, or 18.0%, and increased \$95.7 million, or 17.4%, respectively as compared to the same periods in 2006 primarily as a result of our higher energy rate and increased sales volume.

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 12.7% and 14.2% higher during the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. We increased our fuel factor adjustment rate effective October 1, 2006, and April 1, 2007, resulting in an increase to our total energy rate of approximately 5.2% and 7.2%, respectively. These increases were implemented due to our continued rising fuel and

purchased power costs and differences between actual costs incurred and anticipated costs upon which our rates were based. Our energy sales volume to our member distribution cooperatives increased 4.3% and 7.6% for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006 as a result of increased requirements for power by our member distribution cooperatives.

The capacity costs we incurred, and thus the capacity-related revenues we reflected pursuant to the formulary rate, for the three and nine months ended September 30, 2007, increased \$10.2 million, or 19.0%, and \$8.1 million, or 4.9%, respectively, as compared to the same periods in 2006. The increase in capacity costs related primarily to an increase in purchased capacity costs.

Our average costs to member distribution cooperatives per MWh increased \$8.45, or 13.1%, and \$5.99, or 9.1%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, as a result of the increase in our total energy rates primarily related to our increased purchased power costs.

Sales to Non-Members. Sales to non-members consist of sales of excess purchased energy and sales of excess generated energy. We primarily sell excess energy to PJM Interconnection, LLC. (“PJM”) under its rates for providing energy imbalance services. Non-member revenue increased by \$4.9 million, or 25.0%, and \$11.4, or 18.8%, in the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. The increase in non-member revenue is primarily due to an increase in the volume of excess energy sales. The volume of excess energy sales increased 52.5% and 31.3% for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. Excess energy results from changes in our purchased power portfolio, differences between actual and forecasted energy needs, as well as changes in market conditions.

Operating Expenses

We supply our member distribution cooperatives’ power requirements, consisting of capacity requirements and energy requirements, through (i) our interests in electric generating facilities which consist of a 50% interest in Clover, an 11.6% interest in North Anna, our Louisa combustion turbine facility (“Louisa”), our Marsh Run combustion turbine facility (“Marsh Run”), our Rock Springs combustion turbine facility (“Rock Springs”), and our distributed generation facilities, and (ii) power purchases from third parties through power purchase contracts and forward, short-term and spot market energy purchases. Our energy supply for the three and nine months ended September 30, 2007 and 2006, was as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2007		2006		2007		2006	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	855,394	23.0 %	861,235	24.8 %	2,475,009	23.5 %	2,598,499	27.1 %
North Anna	389,675	10.5	469,832	13.6	1,209,251	11.4	1,298,083	13.5
Louisa	150,743	4.1	175,565	5.1	190,543	1.8	205,249	2.1
Marsh Run	181,723	4.9	188,726	5.4	249,212	2.4	221,420	2.3
Rock Springs	28,482	0.8	48,968	1.4	45,014	0.4	53,377	0.6
Distributed generation	489	-	606	-	646	-	711	-
Total generated	<u>1,606,506</u>	<u>43.3</u>	<u>1,744,932</u>	<u>50.3</u>	<u>4,169,675</u>	<u>39.5</u>	<u>4,377,339</u>	<u>45.6</u>
Purchased:								
Total purchased	<u>2,101,477</u>	<u>56.7</u>	<u>1,725,499</u>	<u>49.7</u>	<u>6,377,778</u>	<u>60.5</u>	<u>5,219,015</u>	<u>54.4</u>
Total available energy	<u>3,707,983</u>	<u>100.0 %</u>	<u>3,470,431</u>	<u>100.0 %</u>	<u>10,547,453</u>	<u>100.0 %</u>	<u>9,596,354</u>	<u>100.0 %</u>

We meet the majority of our member distribution cooperatives’ capacity requirements and a portion of their energy requirements through our ownership interests in Clover, North Anna, Louisa, Marsh Run, and Rock Springs. We purchase capacity and energy from the market to supply the remaining needs of our member distribution cooperatives.

Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. Base load generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs, but nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities also have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run and Rock Springs. Owners of nuclear

and other power plants incur the embedded fixed costs of these facilities whether or not the units operate. When either Clover or North Anna is off-line, we must purchase replacement energy from either Virginia Electric & Power Company (“Virginia Power”) or from the market. As a result, our operating expenses, and consequently our rates to our member distribution cooperatives, are more significantly affected by the operations of Clover and North Anna than by our combustion turbine facilities. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility, but are more expensive to operate; therefore, we operate them only when the market price of energy makes their operation economical or when their operation is required by PJM for system reliability purposes. The output of Clover and North Anna for the three and nine months ended September 30, 2007 and 2006, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	Clover				North Anna			
	Three Months Ended		Nine Months Ended		Three Months Ended		Nine Months Ended	
	September 30,		September 30,		September 30,		September 30,	
	2007	2006	2007	2006	2007	2006	2007	2006
Unit 1	88.2 %	90.3 %	86.4 %	91.3 %	74.8 %	99.9 %	91.4 %	86.1 %
Unit 2	93.0	89.1	87.4	91.0	90.8	99.5	82.0	100.0
Combined	90.6	89.7	86.9	91.2	82.8	99.7	86.7	93.1

Clover. During the nine months ended September 30, 2007, Clover Units 1 and 2 were off-line for 14 days and 13 days, respectively, for scheduled maintenance outages. During the nine months ended September 30, 2006, Clover Units 1 and 2 were each off-line for five days for scheduled maintenance outages. Clover Units 1 and 2 experienced minor unscheduled outages for the three and nine months ended September 30, 2007 and 2006.

North Anna. On September 9, 2007, North Anna Unit 1 was taken off-line for a scheduled refueling and maintenance outage and was returned to service on October 15, 2007. On March 18, 2007, North Anna Unit 2 was taken off-line for a scheduled refueling and maintenance outage and was returned to service on April 22, 2007. North Anna Units 1 and 2 experienced unscheduled outages during the nine months ended September 30, 2007. During the nine months ended September 30, 2006, North Anna Unit 1 was off-line for 29 days for a scheduled refueling and maintenance outage. North Anna Unit 1 experienced minor unscheduled outages during the nine months ended September 30, 2006. North Anna Unit 2 did not experience any outages during the nine months ended September 30, 2006.

Combustion turbine facilities. During the three and nine months ended September 30, 2007 and 2006, the operational availability of Louisa, Marsh Run and Rock Springs was as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
Louisa	99.0 %	99.5 %	95.7 %	99.6 %
Marsh Run	100.0	99.5	98.7	99.6
Rock Springs	99.9	100.0	99.2	93.2

The components of our operating expenses for the three and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Fuel	\$ 57,649	\$ 65,636	\$ 120,166	\$ 120,936
Purchased power	167,647	109,675	473,103	359,796
Deferred energy	(12,951)	339	(19,857)	(8,395)
Operations and maintenance	11,235	8,459	34,172	26,097
Administrative and general	8,811	7,530	25,424	24,879
Depreciation, amortization and decommissioning	9,365	9,628	28,189	28,922
Amortization of regulatory asset/(liability), net	624	444	1,517	1,137
Accretion of asset retirement obligations	732	651	2,197	1,953
Taxes other than income taxes	1,923	2,245	5,557	5,358
Total Operating Expenses	<u>\$ 245,035</u>	<u>\$ 204,607</u>	<u>\$ 670,468</u>	<u>\$ 560,683</u>

Aggregate operating expenses increased \$40.4 million, or 19.8%, and \$109.8 million, or 19.6%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, primarily due to changes in purchased power expense, deferred energy, and operations and maintenance expense. For the three months ended September 30, 2007, the increase in operating expenses was slightly offset by a decrease in fuel expense.

Purchased power expense increased \$58.0 million, or 52.9%, and \$113.3 million, or 31.5%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, due to an increase in the volume of purchased power and an increase in the average cost of purchased power. For the three and nine months ended September 30, 2007, the volume of purchased power increased 21.8% and 22.2%, respectively, and the average cost of purchased power increased 25.5% and 7.6%, respectively, as compared to the same periods in 2006. During a portion of the nine months ended September 30, 2007, our Clover and North Anna units were not available due to scheduled maintenance and refueling outages; which increased our volume of purchased power. The volume of purchased power also increased due to the increased requirements of our member distribution cooperatives. The increase in the average cost of purchased power is reflective of the timing of our forward purchases relative to the prevailing market prices at the time of those purchases.

Deferred energy expense changed \$13.3 million, and \$11.5 million, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. During the three months ended September 30, 2007, we under-collected \$13.0 million in energy costs; whereas in the three months ended September 30, 2006, we over-collected \$0.3 million in energy costs. During the nine months ended September 30, 2007, we under-collected \$19.9 million in energy costs as compared to an under-collection of \$8.4 million for the same period in 2006. At September 30, 2007 and 2006, we had an under-collected deferred energy balance of \$34.8 million and \$29.7 million, respectively.

Operations and maintenance expense increased \$2.8 million, or 32.8%, and \$8.1 million, or 30.9%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. The increase in operations and maintenance expense was primarily related to the scheduled maintenance outages at Clover and North Anna.

Fuel expense decreased \$8.0 million, or 12.2%, for the three months ended September 30, 2007, as compared to the same period in 2006. The decrease in fuel expense is primarily related to decreased fuel consumption due to the reduction in dispatch of our combustion turbine facilities in the three months ended September 30, 2007, as compared to the same period in 2006. Fuel expense was relatively flat for the nine months ended September 30, 2007, as compared to the same period in 2006.

Other Items

Investment Income. Investment income increased \$1.6 million, or 73.3%, and \$4.1 million, or 64.0%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, primarily due to income earned on our increased average balances in cash and temporary investments.

Interest Charges, net. The primary factors affecting our interest expense are scheduled payments of principal on our indebtedness and interest related to our potential liability associated with our dispute with Norfolk Southern Railway Company (“Norfolk Southern”).

The major components of interest charges, net for the three and nine months ended September 30, 2007 and 2006, were as follows:

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2007	2006	2007	2006
	(in thousands)		(in thousands)	
Interest expense on long-term debt	\$ (13,622)	\$ (13,880)	\$ (40,858)	\$ (41,749)
Other	(1,896)	(1,563)	(5,110)	(3,818)
Total Interest Charges	(15,518)	(15,443)	(45,968)	(45,567)
Allowance for borrowed funds used during construction	22	137	185	191
Interest Charges, net	<u>\$ (15,496)</u>	<u>\$ (15,306)</u>	<u>\$ (45,783)</u>	<u>\$ (45,376)</u>

Interest charges, net remained relatively flat for the three and nine months ended September 30, 2007, as compared to the same periods in 2006. Other interest expense increased \$0.3 million, or 21.3% and \$1.3 million, or 33.8%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006, primarily as a result of accrued interest related to our dispute with Norfolk Southern.

Net Margin. Our net margin, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, increased \$2.0 million, or 65.2%, and \$2.1 million, or 22.8%, for the three and nine months ended September 30, 2007, respectively, as compared to the same periods in 2006. The increase is the result of an additional equity contribution of \$2.0 million during the three months ended September 30, 2007.

Financial Condition

The principal changes in our financial condition from December 31, 2006 to September 30, 2007, were caused by increases in investments—other, accrued expenses, accounts payable, deferred energy and accounts payable—members, partially offset by decreases in accounts receivable—deposits, and regulatory assets. Investments—other increased \$71.9 million related to the return of \$23.6 million in collateral we were required to post with our counterparties at December 31, 2006, additional cash invested due to our margin stabilization balance and cash provided by operations. Accrued expenses increased \$24.7 million primarily related to accrued interest and accrued transportation costs related to our dispute with Norfolk Southern. Accounts payable increased \$20.7 million primarily as a result of increased purchased power invoices. Deferred energy increased \$19.9 million as a result of the under-collection of our energy costs. Accounts payable—members increased \$15.9 million primarily as a result of an increased margin stabilization adjustment in 2007 as compared to the same period in 2006 slightly offset by a reduction in member prepayments. Accounts receivable—deposits decreased \$23.6 million related to the return to us of collateral posted as of December 31, 2006, due to changes in energy prices. Regulatory assets decreased \$16.0 million primarily due to the change in the fair value of our derivatives.

Liquidity and Capital Resources

Operations. Historically, our operating cash flows have been sufficient to meet our short- and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. During the first nine months of 2007 our operating activities provided cash flow of \$141.3 million. During the first nine months of 2006 cash needs exceeded our cash flows from operating activities by \$3.7 million. Operating activities during the first nine months of 2007 were primarily impacted by the change in current liabilities, current assets, deferred energy, and regulatory assets and liabilities. Current liabilities changed \$67.3 million primarily as a result of increased interest payable, increased accrued transportation costs related to our dispute with Norfolk Southern, increased accounts payable related to purchased power invoices and increased accounts payable—members related to the change in the margin stabilization adjustment slightly offset by a decrease in member prepayment balances. Current assets changed \$25.5 million primarily due to the return to us of \$23.6 million in collateral we were required to post as of December 31, 2006. Deferred energy changed \$19.9 million as a result of the under-collection of energy costs. Regulatory assets and liabilities changed \$17.5 million primarily due to the change in the fair value of our derivatives.

Financing Activities. In addition to liquidity from our operating activities, we maintain committed lines of credit and revolving credit facilities to cover short-term and medium-term funding needs. As of September 30, 2007, our total lines of credit were \$155.0 million, and our total revolving credit facilities were \$125.0 million. At September 30, 2007 and 2006, we had no short-term borrowings or letters of credit outstanding under any of these arrangements. We expect the working capital lines of credit and revolving credit facilities to be renewed as they expire.

Investing Activities. Investing activities in the first nine months of 2007 were primarily impacted by activity related to available for sale securities, interest earned on investments—other and cash and cash equivalents, as well as electric plant additions for our generating facilities.

Auction Rate Securities. As of September 30, 2007, we had \$46.0 million invested in auction rate securities. These investments are included in investments—other on our Condensed Consolidated Balance Sheet and classified as available for sale. Auction rate securities pay a variable rate of interest which resets periodically in connection with the auction to purchase or sell the securities.

The volatility in the fixed income markets during the third quarter of 2007 resulted in a number of our auction rate securities having auctions that were not fully subscribed, which auction agents describe as failed auctions. At September 30, 2007 we had \$33.9 million invested in auction rate securities with failed auctions. Similarly, as of November 8, 2007, we had \$46.0 million invested in auction rate securities and we had \$33.9 million invested in auction rate securities with failed auctions. These failed auctions resulted in the interest rates on these auction rate securities resetting at a predetermined spread to LIBOR, which, depending on the security, has ranged from 100 basis points to 150 basis points. All of the auction rate securities we owned at September 30 and November 8, 2007 were rated AA or AAA by Standard & Poors' Rating Services, Aa2 or Aaa by Moody's Investors Service, or AAA by Fitch, Inc.

Generally, the periodic auctions provide owners of auction rate securities the opportunity to liquidate their investment at par value. In the event of failed auctions these securities are typically illiquid. If the auction rate securities we own continue to experience failed auctions or their credit ratings deteriorate, we may adjust the carrying value of these investments. Based on our cash and cash equivalents balance and our expected operating cash flows, we currently do not anticipate the lack of liquidity for our auction rate securities will have a material impact on us.

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**ITEM 3. QUANTITATIVE AND QUALITATIVE
DISCLOSURES ABOUT MARKET RISK**

No material changes occurred in our exposure to market risk during the third quarter of 2007.

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely manner. We have established a Disclosure Assessment Committee comprised of members from senior and middle management to assist in this evaluation. There have been no significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the past fiscal quarter.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Ragnar Benson

In December 2002, we entered into a contract with Ragnar Benson, Inc. ("RBI") for engineering, procurement and construction services relating to the construction of our Marsh Run combustion turbine facility. On December 23, 2004, we terminated the contract with RBI for default and filed suit in the U.S. District Court for the Eastern District of Virginia, Richmond Division, against RBI. On June 13, 2005, we executed an agreement with RBI's surety, Seaboard Surety Company ("Seaboard"), under which it assumed all responsibilities for the final completion of the Marsh Run facility in accordance with the terms of the original agreement with RBI. RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for reorganization on October 14, 2005. Because RBI filed for reorganization during the legal proceeding, we served a lawsuit against Seaboard on February 10, 2006, in order to enforce the eventual outcome of the suit with RBI. On August 23, 2007, we settled our legal disputes with Seaboard. In full settlement of our legal disputes with Seaboard, we received a payment of \$3.0 million from Seaboard and we were released of any and all remaining payment obligations. At the time of the settlement we had a \$5.7 million liability recorded which was reversed based on the terms of the settlement. The \$8.7 million impact of the settlement resulted in a reduction of the cost of our Marsh Run facility. The terms of our agreement provided for the assignment by ODEC to Seaboard of all of ODEC's rights and claims against RBI in the current reorganization proceedings including the judgment obtained against RBI, and Seaboard and ODEC each released the other from any and all claims, arising out of or related to the Marsh Run Project.

NOVEC

In the legal proceedings related to Northern Virginia Electric Cooperative ("NOVEC"), on July 6, 2007, FERC filed its brief with the United States Court of Appeals for the District of Columbia in response to NOVEC's May 7, 2007 brief. We filed an intervenor's brief on July 23, 2007, NOVEC filed its reply brief on August 21, 2007, and all parties filed final briefs on September 11, 2007. On October 29, 2007, the court issued an order scheduling oral argument for January 15, 2008. For further description of our legal proceedings related to NOVEC, see Part I, Item 3 of our 2006 Annual Report on Form 10-K.

Other Matters

No material developments have occurred in our legal proceedings with Norfolk Southern or FERC Proceedings Related to Potential Reorganization, since the filing of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007. See "Legal Proceedings" in Part II, Item 1 of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2007. Other than legal proceedings arising out of the ordinary course of business, which management believes will not have a material adverse impact on our results of operations or financial condition, there is no other litigation pending or threatened against us.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in "Risk Factors" in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2006, which could affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

ITEM 5 – OTHER INFORMATION

NOVEC

We are currently in discussions with NOVEC about the possible termination of its wholesale power contract and its withdrawal as a member of ODEC. We will not consider any termination of the wholesale power contract or take any other action in connection with the resolution of our issues with NOVEC that we believe in any way could adversely affect our financial condition or that of our other member distribution cooperatives.

ITEM 6. EXHIBITS

- 31.1 Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
- 31.2 Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
- 32.1 Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
- 32.2 Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350

EXHIBIT INDEX

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION OF PRESIDENT AND CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jackson E. Reasor, certify that:

- 1 I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
- 2 Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
- 3 Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
- 4 The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
- 5 The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2007

/s/Jackson E. Reasor
Jackson E. Reasor
President and Chief Executive Officer
(Principal Executive Officer)

OLD DOMINION ELECTRIC COOPERATIVE

**CERTIFICATION OF PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER
PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Robert L. Kees, certify that:

- 1 I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
- 2 Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
- 3 Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
- 4 The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
- 5 The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the Audit Committee of registrant's Board of Directors (or persons performing the equivalent function):
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 9, 2007

/s/Robert L. Kees
Robert L. Kees
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

