
**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 March 31, 2006

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**

	March 31, 2006	December 31, 2005
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
In service	\$ 1,519,919	\$ 1,519,578
Less accumulated depreciation	(481,022)	(470,735)
	1,038,897	1,048,843
Nuclear fuel, at amortized cost	7,843	9,018
Construction work in progress	19,070	16,365
Net Electric Plant	1,065,810	1,074,226
Investments:		
Nuclear decommissioning trust	82,938	79,464
Lease deposits	163,703	163,156
Other	4,560	12,193
Total Investments	251,201	254,813
Current Assets:		
Cash and cash equivalents	56,108	98,633
Deposits	-	24,686
Accounts receivable	6,840	25,242
Accounts receivable - members	63,778	80,569
Fuel, materials and supplies	29,678	25,669
Deferred energy	49,010	21,328
Prepayments	3,206	3,304
Total Current Assets	208,620	279,431
Deferred Charges:		
Regulatory assets	41,718	43,753
Other	40,818	60,143
Total Deferred Charges	82,536	103,896
Total Assets	\$ 1,608,167	\$ 1,712,366
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 274,823	\$ 271,833
Non-controlling interest	13,137	25,062
Long-term debt	833,778	832,980
Total Capitalization	1,121,738	1,129,875
Current Liabilities		
Long-term debt due within one year	22,917	22,917
Accounts payable	54,397	89,854
Accounts payable-members	52,689	64,110
Accounts payable-deposits	-	24,686
Accrued expenses	41,132	33,740
Total Current Liabilities	171,135	235,307
Deferred Credits and Other Liabilities		
Asset retirement obligation	49,461	48,810
Obligations under long-term leases	166,188	166,043
Regulatory liabilities	63,814	95,271
Other	35,831	37,060
Total Deferred Credits and Other Liabilities	315,294	347,184
Commitments and Contingencies		
Total Capitalization and Liabilities	\$ 1,608,167	\$ 1,712,366

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	
	March 31,	
	2006	2005
	(in thousands)	
Operating Revenues	\$ 203,461	\$ 171,591
Operating Expenses:		
Fuel	24,465	25,563
Purchased power	161,364	116,837
Deferred energy	(27,682)	(17,608)
Operations and maintenance	8,060	8,798
Administrative and general	8,287	7,919
Depreciation, amortization and decommissioning	9,660	9,664
Amortization of regulatory asset/(liability), net	195	971
Taxes other than income taxes	1,560	1,591
Accretion	651	618
Total Operating Expenses	<u>186,560</u>	<u>154,353</u>
Operating Margin	<u>16,901</u>	<u>17,238</u>
Other (Expense)/Income, net	(100)	(78)
Investment Income	2,075	839
Interest Charges, net	<u>(14,922)</u>	<u>(14,645)</u>
Net Margin Before Income Taxes and Non-Controlling Interest	<u>3,954</u>	<u>3,354</u>
Income Taxes	(385)	(166)
Non-Controlling Interest	<u>(579)</u>	<u>(249)</u>
Net Margin	<u>2,990</u>	<u>2,939</u>
Patronage Capital - Beginning of Period	<u>271,833</u>	<u>259,724</u>
Patronage Capital - End of Period	<u>\$ 274,823</u>	<u>\$ 262,663</u>

OLD DOMINION ELECTRIC COOPERATIVE

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

	Three Months Ended	
	March 31,	
	2006	2005
	(in thousands)	
Net Margin	<u>\$ 2,990</u>	<u>\$ 2,939</u>
Other Comprehensive Income:		
Unrealized loss on available for sale securities	-	(9)
Unrealized (loss)/gain on derivative contracts ⁽¹⁾	<u>(12,504)</u>	<u>8,910</u>
Other Comprehensive Income before Non-controlling interest	<u>(12,504)</u>	<u>8,901</u>
Less: Non-controlling interest in comprehensive income	<u>12,504</u>	<u>(8,910)</u>
Comprehensive Income	<u>\$ 2,990</u>	<u>\$ 2,930</u>

⁽¹⁾ Unrealized (loss)/gain on derivative contracts net of taxes of \$8.0 and \$5.7 million for the three months ended March 31, 2006 and March 31, 2005, respectively.

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended	
	March 31,	
	<u>2006</u>	<u>2005</u>
	(in thousands)	
Operating Activities:		
Net Margin	\$ 2,990	\$ 2,939
Adjustments to reconcile net margins to net cash provided by (used for) operating activities:		
Depreciation, amortization and decommissioning	9,660	9,664
Other non-cash charges	2,795	2,761
Non-controlling interest	579	249
Amortization of lease obligations	2,718	2,580
Interest on lease deposits	(2,616)	(2,475)
Change in current assets	55,968	(718)
Change in deferred energy	(27,682)	(17,608)
Change in current liabilities	(56,179)	21,452
Change in regulatory assets and liabilities	(32,069)	6,256
Deferred charges and credits	(1,710)	7,303
Net Cash (Used for) Provided by Operating Activities	<u>(45,546)</u>	<u>32,403</u>
Financing Activities:		
Obligations under long-term leases	<u>(503)</u>	<u>(432)</u>
Net Cash (Used for) Financing Activities	<u>(503)</u>	<u>(432)</u>
Investing Activities:		
Purchases of available for sale securities	(7,675)	-
Proceeds from sale of available for sale securities	15,350	7,500
Increase in other investments	(869)	(781)
Electric plant additions	<u>(3,282)</u>	<u>(2,185)</u>
Net Cash Provided by Investing Activities	<u>3,524</u>	<u>4,534</u>
Net Change in Cash and Cash Equivalents	(42,525)	36,505
Cash and Cash Equivalents - Beginning of Period	<u>98,633</u>	<u>17,564</u>
Cash and Cash Equivalents - End of Period	<u>\$ 56,108</u>	<u>\$ 54,069</u>

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 March 31, 2006, and our consolidated results of operations, comprehensive income, and cash flows for the three months ended March 31, 2006 and 2005. The consolidated results of operations for the three months ended March 31, 2006, 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 2005 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 (“Old Dominion” 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 became the primary beneficiary of TEC in 2001. We first consolidated TEC’s financial position as of December 31, 2004, and beginning January 1, 2005, TEC’s operations were also consolidated as a result of our adoption of the Interpretation. 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 \$15.4 million and \$36.1 million at March 31, 2006, and December 31, 2005, 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 for use as a basis in determining the price of power in certain forward power purchase agreements. These derivatives do not qualify for the normal purchases/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. Hedge ineffectiveness was immaterial for the three months ended March 31, 2006 and 2005.

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. As of December 31, 2005, our counterparties were required to post \$24.7 million in deposits in accordance with the terms of our respective master power purchase and sales agreements with them. At March 31, 2006, due to changes in energy prices, our counterparties were not required to post deposits.

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 Clover. The agreement, which was later assigned to 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.

As of December 31, 2004, we recorded a liability related to the Norfolk Southern dispute and on March 8, 2005, our board of directors approved the creation of the related regulatory asset. The regulatory asset is being amortized over 21 months beginning April 1, 2005 and the amortization of the regulatory asset and 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 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. Construction of the facility began in April 2003 and the facility was required to be substantially complete in the second quarter of 2004. The facility ultimately became available for commercial operation on September 15, 2004, but is still not substantially complete according to the terms of the contract. 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 seeking liquidated damages for delay in completion of the project up to \$15.0 million and damages for breach of contract up to \$5.0 million. RBI filed a counterclaim for damages exceeding \$15.0 million related to conditions they claim to have encountered during construction. We filed an answer to RBI's counterclaim denying any liability to RBI. During the discovery phase of the legal proceeding, RBI revised its claim from \$15.0 million to \$33.0 million.

On September 27, 2005, the U.S. District Court for the Eastern District of Virginia, Richmond Division, ruled on motions for partial summary judgment in our claims against RBI. Specifically, the court granted our motion for partial summary judgment pertaining to claims of entitlement to a change order and fraud allegations, it dismissed six of RBI's counterclaims, including all counterclaims pertaining to fraud, and it limited our possible recovery of liquidated damages to the liquidated damages cap of approximately \$4.7 million. The trial began October 11, 2005 and concluded October 26, 2005. During the trial, RBI revised its claim from \$33.0 million to \$36.0 million. The case is pending in the U.S. District Court for the Eastern District of Virginia, Richmond Division.

RBI and its parent companies, The Austin Company and Austin Holdings, Inc., filed for bankruptcy under Chapter 11 of the bankruptcy code on October 14, 2005. The automatic litigation stay was lifted for the case between RBI and Old Dominion.

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. Since RBI declared bankruptcy 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.

We have reviewed the asserted claims of RBI and Seaboard and believe they are without merit. We do not believe any liability is estimable or probable and we intend to vigorously defend these claims. If it is ultimately determined that we owe any such amounts to RBI, 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 to our member distribution cooperatives.

5. *Subsequent Event.* On April 11, 2006, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 11.9%, effective April 1, 2006. This increase was implemented due to continued rising energy costs. Effective April 1, 2006, we decreased the demand component of our rate approximately 1.8% in accordance with the budget that our Board of Directors approved in December 2005. Increases or decreases in our budget automatically amend the demand component of our formulary rate.

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 March 31, 2006, 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, 2005. These policies include 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 ("Old Dominion" or "we" or "our") and TEC Trading, Inc. ("TEC") effective December 31, 2005. See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

Overview

Old Dominion 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 months ended March 31, 2006, were impacted by changing conditions in the energy markets and milder weather. These changes impacted our purchased power costs and the fair value of our derivatives, as well as our deferred energy balance. Sales of energy to non-members increased as a result of our strategy to hedge a greater percentage of our exposure to spot market prices under purchasing arrangements and differences between actual and forecasted energy needs as well as excess energy as a result of milder than anticipated weather.

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 one minor exception, 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 amount in the formulary rate that requires FERC approval prior to any adjustment. 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 members and non-members. Our operating revenues by type of purchaser for the three months ended March 31, 2006 and 2005, were as follows:

	Three Months Ended	
	March 31,	
	2006	2005
	(in thousands)	
Revenues:		
Member distribution cooperatives	\$ 176,815	\$ 153,285
Non-member revenues	26,646	18,306
Total revenues	<u>\$ 203,461</u>	<u>\$ 171,591</u>

Our energy sales in megawatt hours (“MWh”) to our members and non-members for the three months ended March 31, 2006 and 2005, were as follows:

	Three Months Ended	
	March 31,	
	2006	2005
	(in MWh)	
Energy sales:		
Member distribution cooperatives	2,793,266	2,886,703
Non-member energy sales	476,586	417,617
Total energy sales	<u>3,269,852</u>	<u>3,304,320</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 quarter. 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. 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, 2005, for a discussion of our Margin Stabilization Plan.

Revenues from sales to our member distribution cooperatives by formulary rate component and our average costs to our member distribution cooperatives in MWh for the three months ended March 31, 2006 and 2005, were as follows:

	Three Months Ended	
	March 31,	
	2006	2005
	(in thousands)	
Revenues from sales to member distribution cooperatives:		
Base energy revenues	\$ 50,229	\$ 51,797
Fuel factor adjustment revenues	68,336	46,994
Total energy revenues	118,565	98,791
Demand (capacity) revenues	58,250	54,494
Total revenues from sales to member distribution cooperatives	<u>\$ 176,815</u>	<u>\$ 153,285</u>
Average costs to member distribution cooperatives (per MWh) ⁽¹⁾	\$ 63.30	\$ 53.10

⁽¹⁾ Our average costs to member distribution cooperatives are based on the blended cost of power.

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 or heating systems, respectively. Mild weather generally reduces the requirement because air conditioning and heating systems are operated less.

Three Months Ended March 31, 2006 compared to Three Months ended March 31, 2005:

Total revenues from sales to our member distribution cooperatives for the three months ended March 31, 2006, increased \$23.5 million, or 15.4%, over the same period in 2005, primarily as a result of higher energy rates and higher incurred capacity costs (which are reflected in revenues in the period in which they are expensed).

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 24.0% higher during the three months ended March 31, 2006, as compared to the same period in 2005. We increased our fuel factor adjustment rate effective April 1, 2005, and October 1, 2005, resulting in an increase to our total energy rate of approximately 14.6% and 8.1%, respectively. These increases were implemented due to continued rising energy costs that resulted in increased fuel and purchased power costs.

The capacity costs we incurred, and thus the capacity-related revenues we reflected pursuant to the formulary rate, for the three months ended March 31, 2006, as compared to the same period in 2005, increased \$3.8 million, or 6.9%, primarily related to increased transmission charges and a reclassification of certain costs previously classified as energy costs pursuant to the settlement agreement in our FERC proceedings.

Our average costs to member distribution cooperatives per MWh increased \$10.20 per MWh, or 19.2%, for the three months ended March 31, 2006, as compared to the same period in 2005, primarily as a result of the increase in our total energy rates related to increased fuel and 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 purchased energy to PJM Interconnection, LLC (“PJM”) under its rates for providing energy imbalance services. Prior to May 1, 2005, we also sold excess energy from the Clover Power Station (“Clover”) to Virginia Power pursuant to the requirements of the Clover operating agreement. Non-member revenue increased by \$8.4 million, or 45.6%, in the three months ended March 31, 2006, and non-member energy sales in MWh increased 58,969 MWh, or 14.1%, as compared to the same period in 2005. The increase in non-member revenue for the three months ended March 31, 2006, is primarily due to an increase in the prices at which we sold excess energy to non-members and a slight increase in the volume of excess energy sales. Excess energy, which is sold to third parties, is the result of 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 the North Anna Nuclear Power Station ("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 months ended March 31, 2006 and 2005, was as follows:

	Three Months Ended			
	March 31,			
	2006		2005	
	(in MWh and percentages)			
Generated:				
Clover	906,808	27.1 %	898,957	26.5 %
North Anna	388,494	11.6	464,367	13.7
Louisa	775	-	2,651	0.1
Marsh Run	1,550	0.1	7,896	0.2
Rock Springs	-	-	14,628	0.4
Distributed generation	-	-	364	-
Total generated	<u>1,297,627</u>	<u>38.8</u>	<u>1,388,863</u>	<u>40.9</u>
Purchased:				
Total purchased	<u>2,045,939</u>	<u>61.2</u>	<u>2,005,349</u>	<u>59.1</u>
Total available energy	<u>3,343,566</u>	<u>100.0 %</u>	<u>3,394,212</u>	<u>100.0 %</u>

We satisfy 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 the PJM market, which may be more or less costly. 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. 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. The output of Clover and North Anna for the three months ended March 31, 2006 and 2005, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	Clover		North Anna	
	Three Months Ended		Three Months Ended	
	March 31,		March 31,	
	2006	2005	2006	2005
Unit 1	96.5 %	93.3 %	68.8 %	101.0 %
Unit 2	96.0	97.0	100.6	100.2
Combined	96.3	95.2	84.7	100.6

Clover. During the three months ended March 31, 2006, both Clover Units 1 and 2 were available for dispatch. Clover Unit 2 experienced minor unscheduled outages during the three months ended March 31, 2006. During the three months ended March 31, 2005, Clover Units 1 and 2 experienced minor unscheduled outages. On May 1, 2005, operational control of Virginia Power's transmission facilities was transferred to PJM. With that transfer, all of our member distribution cooperatives' capacity and energy requirements are now within the PJM control area and our generating facilities are now under dispatch control of PJM. Accordingly, Clover Units 1 and 2 are operated pursuant to PJM dispatching requirements.

North Anna. North Anna Unit 1 experienced minor unscheduled outages during the three months ended March 31, 2006. On March 12, 2006, North Anna Unit 1 was taken off-line for a scheduled refueling and maintenance outage and was returned to service on April 10, 2006. North Anna Units 1 and 2 did not experience any outages during the three months ended March 31, 2005.

Combustion turbine facilities. During the three months ended March 31, 2006 and 2005, the operational availability of our Louisa, Marsh Run and Rock Springs combustion turbine facilities was as follows:

	Three Months Ended	
	March 31,	
	2006	2005
Louisa	99.5 %	100.0 %
Marsh Run	99.2	100.0
Rock Springs	92.2	95.6

The components of our operating expenses for the three months ended March 31, 2006 and 2005, were as follows:

	Three Months Ended	
	March 31,	
	2006	2005
	(in thousands)	
Fuel	\$ 24,465	\$ 25,563
Purchased power	161,364	116,837
Deferred energy	(27,682)	(17,608)
Operations and maintenance	8,060	8,798
Administrative and general	8,287	7,919
Depreciation, amortization and decommissioning	9,660	9,664
Amortization of regulatory asset/(liability), net	195	971
Taxes, other than income taxes	1,560	1,591
Accretion	651	618
Total Operating Expenses	<u>\$ 186,560</u>	<u>\$ 154,353</u>

Three Months Ended March 31, 2006 compared to Three Months ended March 31, 2005:

Aggregate operating expenses increased \$32.2 million, or 20.9%, for the three months ended March 31, 2006, as compared to the same period in 2005, primarily due to the increase in purchased power expense, partially offset by the change in deferred energy expense.

Purchased power expense increased \$44.5 million, or 38.1%, for the three months ended March 31, 2006, as compared to the same period in 2005, primarily due to a 35.4% increase in the average cost of purchased power and a slight increase in the volume of purchased power. The increase in the average cost of purchased power is reflective of the overall price increases in energy costs across all markets.

Deferred energy expense changed \$10.1 million, or 57.2%, for the three months ended March 31, 2006, as compared to the same period in 2005. During the three months ended March 31, 2006, we under-collected \$27.7 million in energy costs; whereas in the three months ended March 31, 2005, we under-collected \$17.6 million in energy costs. At March 31, 2006, we had an under-collected deferred energy balance of \$49.0 million.

On April 11, 2006, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 11.9% effective April 1, 2006, due to continued rising energy costs. Effective April 1, 2006, we decreased the demand component of our rate approximately 1.8% in accordance with the budget that our Board of Directors approved in December 2005. Increases or decreases in our budget automatically amend the demand component of our formulary rate.

Other Items

Investment Income. Investment income increased \$1.2 million, or 147.2%, for the three months ended March 31, 2006, as compared to the same period in 2005, primarily due to income earned on our increased average balance in cash and temporary investments as a result of higher member prepayments and counterparty deposits and higher interest rates.

Interest Charges, net. The primary factors affecting our interest expense are scheduled payments of principal on our indebtedness, issuance of new indebtedness and capitalized interest.

The major components of interest charges, net for the three months ended March 31, 2006 and 2005, were as follows:

	Three Months Ended	
	March 31,	
	2006	2005
	(in thousands)	
Interest expense on long-term debt	\$ (13,895)	\$ (14,143)
Other	(1,056)	(558)
Total Interest Charges	(14,951)	(14,701)
Allowance for borrowed funds used during construction	29	56
Interest Charges, net	<u>\$ (14,922)</u>	<u>\$ (14,645)</u>

Interest charges, net increased \$0.3 million, or 1.9%, for the three months ended March 31, 2006, as compared to the same period in 2005.

Net Margin. Our net margin, which is a function of our total interest charges, remained relatively flat for the three months ended March 31, 2006, as compared to the same period in 2005.

Financial Condition

The principal changes in our financial condition from December 31, 2005 to March 31, 2006, were caused by decreases in accounts payable, regulatory liabilities, deposits, accounts payable—deposits, deferred charges—other, accounts receivable, accounts receivable—members, partially offset by the change in deferred energy. Accounts payable decreased \$35.5 million primarily as a result of decreased purchased power in March 2006 as compared to December 2005. Regulatory liabilities decreased \$31.5 million primarily due to the change in the fair value of our derivatives. Deposits and accounts payable—deposits decreased \$24.7 million. As of December 31, 2005, our counterparties were required to post \$24.7 million in deposits in accordance with the terms of our respective master power purchase and sales agreements with them. At March 31, 2006, due to changes in energy prices, our counterparties were not required to post deposits due to the change in market conditions as compared to December 2005. Deferred charges—other decreased \$19.3 million as a result of deferred derivative activity. Accounts receivable decreased \$18.4 million primarily due to the decrease in purchased power receivables. Accounts receivable—members decreased \$16.8 million primarily due to the seasonal difference between December and March sales. Our deferred energy balance represents the net under- or over-collection of energy costs as of the end of the reporting period. These amounts are recovered from or refunded to our member distribution cooperatives in subsequent periods. At December 31, 2005, we had an under-collected deferred energy balance of \$21.3 million as compared to an under-collected deferred energy balance of \$49.0 million at March 31, 2006.

Liquidity and Capital Resources

Operations. Historically, our operating cash flows have been sufficient to meet our short-term and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. However, during the first three months of 2006, our cash needs exceeded our cash inflows from operating activities by \$45.5 million. Our operating activities provided cash flow of \$32.4 million during the first three months of 2005. Operating activities in the first three months of 2006 were primarily impacted by the change in current liabilities, regulatory assets and liabilities, and deferred energy partially offset by the change in current assets. Current liabilities changed \$56.2 million primarily as a result of decreased accounts payable related to purchased power and fuel costs, and decreased accounts payable—deposits as a result of the change in the amount of deposits posted by our counterparties in accordance with the terms of our respective master power purchase and sales agreements with them. Regulatory assets and liabilities changed \$32.1 million primarily due to the change in the fair value of our derivatives. At March 31, 2006, we had an under-collected deferred energy balance of \$49.0 million as compared to an under-collected deferred energy balance of \$21.3 million at December 31, 2005, which resulted in a cash outflow of \$27.7 million. Current assets changed \$56.0 million related to the change in the amount of deposits posted by our counterparties in accordance with the terms of our respective master power purchase and sales agreements with them and decreased accounts receivable and accounts receivable—members.

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 March 31, 2006, we had short-term committed variable rate lines of credit in an aggregate amount of \$180.0 million all of which are available for general working capital purposes. Additionally, we had two committed three-year revolving credit facilities, \$50.0 million each, available for capital expenditures and general corporate purposed. One of these revolving credit facilities expires on March 18, 2007 and the other expires on January 30, 2009.

At March 31, 2006 and 2005, we had no short-term borrowings or letters of credit outstanding under any of these arrangements. We expect the working capital lines of credit to be renewed as they expire.

Investing Activities. Investing activities in the first three months of 2006 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.

OLD DOMINION ELECTRIC COOPERATIVE

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the first quarter of 2006.

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 matter. 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.

OLD DOMINION ELECTRIC COOPERATIVE

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

NOVEC

On April 3, 2006, Northern Virginia Electric Cooperative ("NOVEC") filed with FERC a request for rehearing of its Section 206 Complaint that was denied on March 2, 2006. On May 1, 2006, FERC issued a tolling order granting rehearing for the limited purpose of further consideration. In the tolling order, FERC states that no answers to the rehearing request will be entertained. FERC has the option, at its discretion, to afford parties an opportunity to file briefs or present oral argument on issues raised in the rehearing request. There are no statutory time restrictions with regard to FERC's additional consideration of the matter or its issuance of a final order.

For further description of our legal proceedings for NOVEC, see Part 1, Item 3 of our 2005 Annual Report on Form 10-K.

FERC Proceedings Related to Potential Reorganization

On April 7, 2006, FERC issued an order approving the Contested Partial Settlement with Bear Island Paper Company and the Virginia State Corporation Commission.

On April 20, 2006, the procedural schedule related to NOVEC's intervention in the FERC proceedings related to the potential reorganization was revised.

For further description of our legal proceedings for the FERC Proceedings Related to Potential Reorganization, see Part 1, Item 3 of our 2005 Annual Report on Form 10-K.

Other Matters

No material developments have occurred in our legal proceedings with Norfolk Southern Railway Company or Ragnar Benson, Inc. since the filing of our Annual Report on Form 10-K for the fiscal year ended December 31, 2005. See "Legal Proceedings" in Part 1, Item 3 of our 2005 Annual Report on Form 10-K. 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, 2005, 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

Our Marsh Run combustion turbine facility was declared commercially operable in September 2004 and on March 27, 2006, the facility attained substantial completion.

ITEM 6. EXHIBITS

- 10.1 Amendment No. 3 to Participation Agreement
- 10.2 Amendment No. 2 to Equipment Operating Lease Agreement
- 10.3 Amendment No. 2 to Corrected Foundation Operating Lease Agreement
- 10.4 Investment Agreement
- 10.5 Investment Pledge Agreement
- 10.6 Amendment No. 3 to Payment Undertaking Agreement
- 10.7 Amendment No. 2 to Tax Indemnity Agreement
- 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

SIGNATURE

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.

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

Date: May 12, 2006

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

EXHIBIT INDEX

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
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**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: May 12, 2006

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

**OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION OF PRESIDENT AND CHIEF EXECUTIVE OFFICER
PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the "Company") on Form 10-Q for the period ending March 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jackson E. Reasor, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- 1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- 2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 12, 2006

/s/JACKSON E. REASOR

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

Exhibit 32.2

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION OF PRINCIPAL FINANCIAL AND ACCOUNTING OFFICER
PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-Q for the period ending March 31, 2006 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- 1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- 2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: May 12, 2006

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