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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2005

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 an accelerated filer (as defined in the Exchange Act of Rule 12b-2).
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>June 30,</u> <u>2005</u>	<u>December 31,</u> <u>2004*</u>
	(in thousands)	
ASSETS:	(unaudited)	
Electric Plant:		
In service	\$ 1,514,773	\$ 1,511,848
Less accumulated depreciation	(452,345)	(431,678)
	<u>1,062,428</u>	<u>1,080,170</u>
Nuclear fuel, at amortized cost	7,655	10,493
Construction work in progress	13,489	10,832
Net Electric Plant	<u>1,083,572</u>	<u>1,101,495</u>
Investments:		
Nuclear decommissioning trust	76,489	75,917
Lease deposits	158,070	156,909
Other	15,378	17,694
Total Investments	<u>249,937</u>	<u>250,520</u>
Current Assets:		
Cash and cash equivalents	35,956	17,564
Accounts receivable	7,115	9,438
Accounts receivable - members	74,243	62,402
Fuel, materials and supplies	27,055	29,153
Deferred energy	11,671	-
Prepayments	2,213	2,866
Total Current Assets	<u>158,253</u>	<u>121,423</u>
Deferred Charges:		
Regulatory assets	48,486	53,920
Other	31,723	22,980
Total Deferred Charges	<u>80,209</u>	<u>76,900</u>
Total Assets	<u>\$ 1,571,971</u>	<u>\$ 1,550,338</u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 265,609	\$ 259,724
Non-controlling interest	15,791	8,225
Long-term debt	854,402	852,910
Total Capitalization	<u>1,135,802</u>	<u>1,120,859</u>
Current Liabilities		
Long-term debt due within one year	22,917	22,917
Accounts payable	50,258	59,798
Accounts payable-members	43,180	38,655
Accrued expenses	21,307	14,527
Deferred energy	-	4,807
Deferred taxes	4,563	-
Total Current Liabilities	<u>142,225</u>	<u>140,704</u>
Deferred Credits and Other Liabilities		
Asset retirement obligation	47,531	46,295
Obligations under long-term leases	160,840	159,902
Regulatory liabilities	46,141	41,782
Other	39,432	40,796
Total Deferred Credits and Other Liabilities	<u>293,944</u>	<u>288,775</u>
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	<u>\$ 1,571,971</u>	<u>\$ 1,550,338</u>

* The Condensed Consolidated Balance Sheet at December 31, 2004, has been derived from the audited financial statements at that date, but does not include all disclosures required by generally accepted accounting principles. 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		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Operating Revenues	\$ 160,457	\$ 132,646	\$ 332,048	\$ 267,607
Operating Expenses:				
Fuel	24,222	21,475	49,785	41,600
Purchased power	90,899	71,797	207,736	152,730
Deferred energy	1,130	432	(16,478)	(7,437)
Operations and maintenance	7,626	6,701	16,424	15,526
Administrative and general	7,848	6,957	15,767	14,569
Depreciation, amortization and decommissioning	9,651	7,336	19,315	14,668
Amortization of regulatory asset/(liability), net	202	2,530	1,173	4,286
Taxes other than income taxes	1,571	1,199	3,162	2,419
Accretion	618	553	1,236	1,106
Total Operating Expenses	<u>143,767</u>	<u>118,980</u>	<u>298,120</u>	<u>239,467</u>
Operating Margin	<u>16,690</u>	<u>13,666</u>	<u>33,928</u>	<u>28,140</u>
Other (Expense)/Income, net	(48)	44	(126)	32
Investment Income	1,401	1,402	2,240	1,963
Interest Charges, net	<u>(14,671)</u>	<u>(12,112)</u>	<u>(29,316)</u>	<u>(24,183)</u>
Net Margin Before Income Taxes and Non-Controlling Interest	<u>3,372</u>	<u>3,000</u>	<u>6,726</u>	<u>5,952</u>
Income Taxes	(170)	-	(336)	-
Non-Controlling Interest	<u>(256)</u>	<u>-</u>	<u>(505)</u>	<u>-</u>
Net Margin	<u>2,946</u>	<u>3,000</u>	<u>5,885</u>	<u>5,952</u>
Patronage Capital - Beginning of Period	<u>262,663</u>	<u>250,542</u>	<u>259,724</u>	<u>247,590</u>
Patronage Capital - End of Period	<u>\$ 265,609</u>	<u>\$ 253,542</u>	<u>\$ 265,609</u>	<u>\$ 253,542</u>

OLD DOMINION ELECTRIC COOPERATIVE

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Net Margin	\$ 2,946	\$ 3,000	\$ 5,885	\$ 5,952
Other Comprehensive Income:				
Unrealized gain/(loss) on derivative contracts ⁽¹⁾	(1,772)	111	7,138	111
Other Comprehensive Income	<u>(1,772)</u>	<u>111</u>	<u>7,138</u>	<u>111</u>
Comprehensive Income	<u>\$ 1,174</u>	<u>\$ 3,111</u>	<u>\$ 13,023</u>	<u>\$ 6,063</u>

⁽¹⁾ Unrealized gain/(loss) on derivative contracts net of tax benefit of \$1,133 for the three months ended June 30, 2005, and net of tax expense of \$4,563 for the six months ended June 30, 2005.

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

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended	
	June 30,	
	2005	2004
	(in thousands)	
Operating Activities:		
Net Margin	\$ 5,885	\$ 5,952
Adjustments to reconcile net margins to net cash provided by (used for) operating activities:		
Depreciation, amortization and decommissioning	19,315	14,668
Other non-cash charges	5,537	1,540
Non-controlling interest	505	-
Amortization of lease obligations	5,164	4,966
Interest on lease deposits	(4,955)	(4,755)
Change in current assets	(6,767)	(6,137)
Change in deferred energy	(16,478)	(7,437)
Change in current liabilities	1,765	5,230
Change in regulatory assets and liabilities	10,697	6,175
Deferred charges and credits	2,897	(1,090)
Net Cash Provided by Operating Activities	<u>23,565</u>	<u>19,112</u>
Financing Activities:		
Obligations under long-term leases	(432)	(436)
Net Cash Used for Financing Activities	<u>(432)</u>	<u>(436)</u>
Investing Activities:		
Purchases of available for sale securities	(15,015)	(108,400)
Proceeds from sale of available for sale securities	15,000	115,901
Decrease (Increase) in other investments	855	(2,207)
Electric plant additions	(5,581)	(34,034)
Net Cash Used for Investing Activities	<u>(4,741)</u>	<u>(28,740)</u>
Net Change in Cash and Cash Equivalents	18,392	(10,064)
Cash and Cash Equivalents - Beginning of Period	17,564	31,758
Cash and Cash Equivalents - End of Period	<u>\$ 35,956</u>	<u>\$ 21,694</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 June 30, 2005, and our consolidated results of operations, comprehensive income, and cash flows for the three and six months ended June 30, 2005 and 2004. The consolidated results of operations for the three and six months ended June 30, 2005, 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 2004 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.

TEC was formed in 2001 for the primary purpose of purchasing from us, to sell in the market, power that is not needed to meet the actual needs of our member distribution cooperatives, acquiring natural gas and forward purchase contracts to hedge the price of natural gas to supply our combustion turbine facilities, and taking advantage of other power-related trading opportunities in the market which will help lower our member distribution cooperatives’ costs. TEC does not engage in speculative trading. TEC is a taxable corporation and a provision for income taxes has been established based upon TEC’s pre-tax income using statutory tax rates of 35% for federal purposes and 4% for state purposes.

In accordance with Financial Accounting Standards Board 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 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 \$22.1 million and \$10.2 million at June 30, 2005, and December 31, 2004, 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 two 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 \$0.1 million for the three and six months ended June 30, 2005. There was no hedge ineffectiveness during the quarter ended March 31, 2005, or the year ended December 31, 2004.

4. *Commitments and Contingencies.* See Note 15—Commitments and Contingencies to the Notes to the Consolidated Financial Statements in our 2004 Annual Report on Form 10-K.

On April 1, 2005, during the discovery phase of the trial, Ragnar Benson, Inc. (“RBI”) revised its claim from \$15.0 million to \$33.0 million. We have reviewed the asserted claims of RBI and believe they are without merit. We do not believe any liability is estimable or probable and we intend to vigorously defend these claims.

5. *Reclassifications.* Certain reclassifications have been made to the prior year’s condensed consolidated financial statements to conform to the current year’s presentation.

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 June 30, 2005, 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, 2004. 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 ("Old Dominion" or "we" or "our") and TEC Trading, Inc. ("TEC") effective December 31, 2004. 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, power purchase contracts, and forward, short-term and spot market energy purchases.

The event having the most significant effect on our financial results for the six months ended June 30, 2005, was a delay in Virginia Electric and Power Company ("Virginia Power") becoming a member of PJM Interconnection, LLC ("PJM") and the resulting postponement of the transfer of Virginia Power's operational control of its transmission facilities to PJM. See "Other Information" in Part II, Item 5 of our Quarterly Report on Form 10-Q for the three-months ended March 31, 2005, for more information relating to the effects of Virginia Power joining PJM.

In anticipation of Virginia Power becoming a member of PJM on January 1, 2005, we purchased several forward energy contracts for delivery to the PJM control area beginning on that date for purpose of serving the needs of our member distribution cooperatives on the Virginia mainland. Virginia Power did not join PJM and transfer operational control of its transmission facilities to PJM until May 1, 2005. Although we could have arranged for the energy under these forward energy contracts to be transmitted to our member distribution cooperatives in the Virginia mainland, it was more economical to sell this energy to non-members and procure a similar amount of energy from other sources. As a result, on the revenue side, our sales to non-members increased dramatically because we sold significant amounts of energy to the market that we had initially scheduled for delivery to the PJM control area for our mainland Virginia member distribution cooperatives' power requirements. On the expense side, our purchased power expense also rose 36.0% because we procured significant replacement energy outside of the PJM control area to serve these requirements.

In addition, Virginia Power joining PJM affected our financial results because since May 1, 2005, PJM has dispatched the Clover Power Station ("Clover"), in which we have a 50% undivided interest, below the levels at which Virginia Power has historically

dispatched it. Clover Units 1 and 2 also had scheduled maintenance outages during the second quarter of 2005. The resulting reduction in fuel expense partially mitigated significant increases in fuel expenses relating to the cost of coal. Our average cost of coal increased 50.7%, and our fuel expense increased 19.7% for the first six months of 2005 as compared to the same period in 2004.

Increases of our non-member revenues also were significantly increased by the consolidation of TEC Trading, Inc. ("TEC"), our sole Class B member, in accordance with Financial Accounting Standards Board Interpretation No. 46R, "Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51 ("the Interpretation"). Under the Interpretation, revenues from sales by TEC constitute non-member revenues effective January 1, 2005. Previously our sales of energy to TEC were reflected as member revenues and TEC's sales to third parties were not reflected in our financial statements.

The other significant event broadly affecting our financial results was the availability of our Marsh Run combustion turbine facility for commercial operation effective in September 2004. As a result, depreciation, amortization and decommissioning expense increased; and interest charges, net increased because we ceased capitalizing interest with respect to the facility.

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 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. Because the fuel factor adjustment rate can be revised without FERC approval, we can effectively change our total energy rate to recover all 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 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 extraordinary deductions, and decommissioning cost, which is a fixed amount in the formulary rate that requires FERC approval prior to any adjustment. As of December 23, 2003, decommissioning costs have been fixed at zero, reflecting our assessment that, based on current projections, our decommissioning trust fund is adequately funded. Our demand rate is revised automatically to recover the costs contained in our annual budget and any revisions made by our Board of Directors to our annual budget.

Our operating revenues are derived from power sales to our members and non-members. Sales to members include sales to our Class A members, which are our twelve member distribution cooperatives. Prior to January 1, 2005, sales to members also included sales to our single Class B member, TEC. We 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 the adoption of the Interpretation. Sales between Old Dominion and TEC have been eliminated from our financial statements. TEC's sales to third parties are reflected as non-member revenues. See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1. Our operating revenues by type of purchaser for the three and six months ended June 30, 2005 and 2004, were as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Member revenues:				
Member distribution cooperatives	\$ 149,475	\$ 130,147	\$ 302,760	\$ 262,751
TEC	-	765	-	1,901
Total member revenues	149,475	130,912	302,760	264,652
Non-member revenues	10,982	1,734	29,288	2,955
Total revenues	<u>\$ 160,457</u>	<u>\$ 132,646</u>	<u>\$ 332,048</u>	<u>\$ 267,607</u>

Non-member revenues for 2005 include our sales to TEC of \$10.5 million and \$25.1 million for the three and six months ended June 30, 2005, respectively. TEC is our sole Class B member, the sales of which are now recorded as non-member sales as a result of the consolidation of TEC.

Our energy sales in megawatt hours ("MWh") to our members and non-members for the three months and six months ended June 30, 2005 and 2004, were as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30.	
	2005	2004	2005	2004
	(in MWh)		(in MWh)	
Member energy sales:				
Member distribution cooperatives	2,411,149	2,411,331	5,297,852	5,253,287
TEC	-	13,767	-	46,397
Total energy sales to members	2,411,149	2,425,098	5,297,852	5,299,684
Non-member energy sales	250,890	22,695	668,507	56,242
Total energy sales	<u>2,662,039</u>	<u>2,447,793</u>	<u>5,966,359</u>	<u>5,355,926</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, 2004, 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 six months ended June 30, 2005 and 2004, were as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Revenues from sales to member distribution cooperatives:				
Base energy revenues	\$ 43,528	\$ 43,693	\$ 95,325	\$ 95,051
Fuel factor adjustment revenues	51,015	34,053	98,009	62,057
Total energy revenues	94,543	77,746	193,334	157,108
Demand (capacity) revenues	54,932	52,401	109,426	105,643
Total revenues from sales to member distribution cooperatives	<u>\$149,475</u>	<u>\$130,147</u>	<u>\$302,760</u>	<u>\$262,751</u>
Average costs to member distribution cooperatives (per MWh) ⁽¹⁾	\$ 61.99	\$ 53.97	\$ 57.15	\$ 50.02

⁽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' consumers' 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 Months Ended June 30, 2005 compared to Three Months ended June 30, 2004:

Total revenues from sales to our member distribution cooperatives for the three months ended June 30, 2005, increased \$19.3 million, or 14.9%, over the same period in 2004, primarily as a result of higher energy rates and slightly 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 21.6% higher during the three months ended June 30, 2005, as compared to the same period in 2004. We increased our fuel factor adjustment rate effective October 1, 2004, and April 1, 2005, resulting in an increase to our total energy rate of approximately 6.3% and 14.6%, respectively. These increases were implemented due to continued rising energy costs in 2004 and 2005 resulting in increased fuel and purchased power expenses.

The capacity costs we incurred, and thus the capacity-related revenues we reflected pursuant to the formulary rate, for the three months ended June 30, 2005, as compared to the same period in 2004, increased \$2.5 million, or 4.8%, primarily as a result of slightly higher depreciation and interest expense because of the commercial operation of Marsh Run in September 2004. See "Interest Charges" for a discussion of interest expenses.

Our average costs to member distribution cooperatives per MWh increased \$8.02 per MWh, or 14.9%, for the three months ended June 30, 2005, as compared to the same period in 2004, primarily as a result of the increase in our total energy rates related to increased fuel and purchased power costs.

Six Months Ended June 30, 2005 compared to Six Months ended June 30, 2004:

Total revenues from sales to our member distribution cooperatives for the six months ended June 30, 2005, increased \$40.0 million, or 15.2%, as compared to the same period in 2004 primarily as a result of higher energy rates and slightly 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 22.0% higher during the six months ended June 30, 2005, as compared to the same period in 2004. We increased our fuel factor adjustment rate effective October 1, 2004, and April 1, 2005, resulting in an increase to our total energy rate of approximately 6.3% and 14.6%, respectively. These increases were implemented due to higher than anticipated energy costs in 2004 and 2005 related to continued 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 six months ended June 30, 2005, as compared to the same period in 2004, increased \$3.8 million, or 3.6%, primarily as a result of slightly higher depreciation and interest expense because of the commercial operation of Marsh Run in September 2004. For the six months ended June 30, 2004, costs for Marsh Run, including interest, were being capitalized. See “Interest Charges” for a discussion of interest expenses.

Our average costs to member distribution cooperatives per MWh increased \$7.13 per MWh, or 14.3%, for the six months ended June 30, 2005, as compared to the same period in 2004, primarily as a result of the increase in our total energy rates related to increased fuel and purchased power costs.

Sales to TEC. Beginning January 1, 2005, we reported no sales to TEC because TEC is now consolidated as a result of the adoption of the Interpretation. Sales between Old Dominion and TEC have been eliminated in consolidation and TEC’s sales to third parties are reflected as non-member revenues. See Note 2—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1. Prior to January 1, 2005, sales to TEC consisted primarily of sales of excess energy that we did not need to meet the actual needs of our member distribution cooperatives. We sold the portion of this energy that could not be utilized by our member distribution cooperatives to TEC for resale into the market, or to non-members.

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 under its rates for providing energy imbalance services. Prior to May 1, 2005, we also sold excess energy from Clover to Virginia Power pursuant to the requirements of the Clover operating agreement. Beginning in 2005, TEC’s sales to third parties are also reflected as non-member revenue. Non-member revenue increased by \$9.2 million and \$26.3 million in the three and six months ended June 30, 2005, respectively, over the same periods in 2004 primarily due to increased sales of excess energy. As a result of the delay of Virginia Power joining PJM, we had more excess energy, which was sold to third parties.

Operating Expenses

We supply our member distribution cooperatives’ power requirements, consisting of capacity requirements and energy requirements, through (i) our owned or leased 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”), 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 six months ended June 30, 2005 and 2004, was as follows:

	Three Months Ended				Six Months Ended			
	June 30,		June 30,		June 30,		June 30,	
	2005	2004	2005	2004	2005	2004	2005	2004
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	559,669	20.4 %	655,009	26.0 %	1,458,626	23.8 %	1,533,800	27.7 %
North Anna	467,127	17.1	389,235	15.4	931,494	15.2	841,710	15.2
Louisa	28,068	1.0	83,701	3.3	30,719	0.5	125,455	2.3
Marsh Run	46,445	1.7	-	-	61,073	1.0	-	-
Rock Springs	14,632	0.6	82,388	3.3	22,528	0.3	83,440	1.5
Distributed generation	273	-	-	-	637	-	-	-
Total generated	<u>1,116,214</u>	<u>40.8</u>	<u>1,210,333</u>	<u>48.0</u>	<u>2,505,077</u>	<u>40.8</u>	<u>2,584,405</u>	<u>46.7</u>
Purchased:								
Total purchased	<u>1,622,868</u>	<u>59.2</u>	<u>1,310,356</u>	<u>52.0</u>	<u>3,628,217</u>	<u>59.2</u>	<u>2,945,831</u>	<u>53.3</u>
Total available energy	<u>2,739,082</u>	<u>100.0 %</u>	<u>2,520,689</u>	<u>100.0 %</u>	<u>6,133,294</u>	<u>100.0 %</u>	<u>5,530,236</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 and six months ended June 30, 2005 and 2004, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	Clover				North Anna			
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
	June 30,		June 30,		June 30,		June 30,	
	2005	2004	2005	2004	2005	2004	2005	2004
Unit 1	72.5 %	51.1 %	83.6 %	70.7 %	100.5 %	100.4 %	100.8 %	96.6 %
Unit 2	43.3	86.4	70.6	90.3	99.8	66.9	100.2	83.5
Combined	57.9	68.8	77.1	80.5	100.2	83.7	100.5	90.1

Clover. During the three months ended June 30, 2005, Clover Units 1 and 2 were off-line for nine days and 34 days, respectively, for scheduled maintenance outage. Clover Units 1 and 2 experienced minor unscheduled outages during the three and six months ended June 30, 2005, and June 30, 2004. On May 1, 2005, operational control of the 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. During the three months ended June 30, 2005, Clover Units 1 and 2 were dispatched less by PJM based upon economic factors. When our generating facilities are dispatched less, we purchase power to meet the needs of our member distribution cooperatives. Clover Units 1 and 2 were off-line for 37 days and 18 days, respectively, for scheduled maintenance outages during the three and six months ended June 30, 2004.

North Anna. North Anna Units 1 and 2 did not experience any outages during the three months ended and six months ended June 30, 2005. North Anna Unit 2 was off-line for 28 days for a scheduled refueling outage during the three and six months ended June 30, 2004.

Combustion turbine facilities. During the three and six months ended June 30, 2005, the operational availability of our Louisa, Marsh Run and Rock Springs combustion turbine facilities was as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
Louisa	93.9 %	98.7 %	97.0 %	96.4 %
Marsh Run ⁽¹⁾	96.3	-	98.1	-
Rock Springs	99.2	99.6	97.4	94.0

⁽¹⁾ Marsh Run became commercially operable in September 2004.

The components of our operating expenses for the three and six months ended June 30, 2005 and 2004, were as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Fuel	\$ 24,222	\$ 21,475	\$ 49,785	\$ 41,600
Purchased power	90,899	71,797	207,736	152,730
Deferred energy	1,130	432	(16,478)	(7,437)
Operations and maintenance	7,626	6,701	16,424	15,526
Administrative and general	7,848	6,957	15,767	14,569
Depreciation, amortization and decommissioning	9,651	7,336	19,315	14,668
Amortization of regulatory asset/(liability), net	202	2,530	1,173	4,286
Taxes, other than income taxes	1,571	1,199	3,162	2,419
Accretion	618	553	1,236	1,106
Total Operating Expenses	\$ 143,767	\$ 118,980	\$ 298,120	\$ 239,467

Three Months Ended June 30, 2005 compared to Three Months ended June 30, 2004:

Aggregate operating expenses increased \$24.8 million, or 20.8%, for the three months ended June 30, 2005, as compared to the same period in 2004, primarily due to increases in fuel, purchased power expense.

Fuel expense increased \$2.7 million, or 12.8%, for the three months ended June 30, 2005, as compared to the same period in 2004, primarily as a result of the 67.4% increase in the average cost of coal.

Purchased power expense increased \$19.1 million, or 26.6%, for the three months ended June 30, 2005, as compared to the same period in 2004, primarily due to a 23.9% increase in the volume of purchased power and a slight increase in the average cost 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. The average cost of purchased power for the three months ended June 30, 2005, increased 2.2%, as compared to the same period in 2004. As described above, on May 1, 2005, operational control of Virginia Power's transmission facilities was transferred to PJM. With this 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. During the three months ended June 30, 2005, Clover Units 1 and 2 were dispatched less based upon economic factors. Clover Units 1 and 2 also had scheduled maintenance outages during the second quarter of 2005. When our generating facilities are dispatched less, we purchase power to meet the needs of our member distribution cooperatives.

Depreciation, amortization and decommissioning increased \$2.3 million, or 31.6%, for the three months ended June 30, 2005, because we had depreciation expense related to Marsh Run in 2005 but not for the three months ended June 30, 2004.

On April 13, 2005, our Board of Directors approved an increase to our fuel factor adjustment rate, resulting in an increase to our total energy rate of approximately 14.6% effective April 1, 2005. This increase was implemented due to continued rising energy costs. Additionally, our Board of Directors approved a decrease in our demand rate of approximately 4.3%, effective April 1, 2005. This decrease was implemented due to an overall decline in fixed costs.

Six Months Ended June 30, 2005 compared to Six Months ended June 30, 2004:

Aggregate operating expenses increased \$58.7 million, or 24.5%, for the six months ended June 30, 2005, as compared to the same period in 2004, primarily due to increases in fuel, purchased power, and depreciation, amortization and decommissioning expense, partially offset by a change in deferred energy.

Fuel expense increased \$8.2 million, or 19.7%, for the six months ended June 30, 2005, as compared to the same period in 2004, primarily as a result of the 50.7% increase in the average cost of coal.

Purchased power expense increased \$55.0 million, or 36.0%, for the six months ended June 30, 2005, as compared to the same period in 2004, due to a 23.2% increase in the volume of purchased power and an increase in the average cost 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. The average cost of purchased power for the six months ended June 30, 2005, increased 14.3%, as compared to the same period in 2004. As described above, on May 1, 2005, operational control of Virginia Power's transmission facilities was

transferred to PJM. With this 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.

Depreciation, amortization and decommissioning increased \$4.6 million, or 31.7%, for the six months ended June 30, 2005, because we had depreciation expense related to Marsh Run in 2005 but not for the six months ended June 30, 2004.

Deferred energy expense changed \$9.0 million, or 121.6%, for the six months ended June 30, 2005, as compared to the same period in 2004. During the first six months of 2005, we under-collected \$16.5 million in energy costs; whereas in the first six months of 2004 we under-collected \$7.4 million in energy costs. At June 30, 2005, we had an under-collected deferred energy balance of \$11.7 million.

Other Items

Investment Income. Investment income remained relatively flat for the three months ended June 30, 2005, as compared to the same period in 2004. Investment income increased by \$0.3 million or 14.1% for the six months ended June 30, 2005, as compared to the same period in 2004, primarily due to interest associated with accounts payable—members.

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 and six months ended June 30, 2005 and 2004, were as follows:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2005	2004	2005	2004
	(in thousands)		(in thousands)	
Interest expense on long-term debt	\$ (14,242)	\$ (14,068)	\$ (28,385)	\$ (28,005)
Other	(485)	(936)	(1,043)	(1,757)
Total Interest Charges	(14,727)	(15,004)	(29,428)	(29,762)
Allowance for borrowed funds used during construction	56	2,892	112	5,579
Interest Charges, net	<u>\$ (14,671)</u>	<u>\$ (12,112)</u>	<u>\$ (29,316)</u>	<u>\$ (24,183)</u>

Interest charges, net increased by \$2.6 million, or 21.1%, for the three months ended June 30, 2005, and \$5.1 million, or 21.2%, for the six months ended June 30, 2005, as compared to the same periods in 2004, primarily due to our reduction in capitalized interest associated with Marsh Run. We ceased capitalizing interest on Marsh Run in September 2004 when the facility became commercially operable. Capitalized interest is computed monthly using an interest rate, which reflects our embedded cost of indebtedness, multiplied by our investment in projects under construction.

Net Margin. Our net margin, which is a function of our total interest charges, remained relatively flat for the three and six months ended June 30, 2005, as compared to the same period in 2004.

Financial Condition

The principal changes in our financial condition from December 31, 2004 to June 30, 2005, were caused by increases in accounts receivable—members, non-controlling interest related to the consolidation of TEC, deferred taxes, the decrease in net electric plant, and the change in deferred energy. Accounts receivable—members increased \$11.8 million, or 19.0% due to increased revenues. Non-controlling interest related to the consolidation of TEC increased \$7.6 million, or 92.0%, from December 31, 2004, to June 30, 2005 due to the increase in unrealized gain on derivatives recorded on TEC's financial statements as a result of a change in the market value of its contracts for delivery of gas in the future at specified prices. Deferred taxes increased \$4.6 million, due to the consolidation of TEC. Net electric plant decreased \$17.9 million as a result of the depreciation of these assets. 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. The deferred energy balance changed from a \$4.8 million liability (over-collection of costs) at December 31, 2004, to an \$11.7 million asset (under-collection of costs) at June 30, 2005.

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. Our operating activities provided cash flow of \$23.6 million and \$19.1 million during the first six months of 2005 and 2004, respectively. Operating activities were impacted primarily by changes in the first six months of 2005 in deferred energy and the change in regulatory assets and liabilities. At June 30, 2005, we had an under-collected deferred energy balance of \$11.7 million as compared to an over-collected deferred energy balance of \$4.8 million at December 31, 2004, which resulted in a cash outflow of \$16.5 million. Regulatory assets and liabilities changed \$4.5 million primarily due to deferred derivative activity.

Financing Activities. In addition to liquidity from our operating activities, we maintain committed lines of credit to cover short-term funding needs. As of June 30, 2005, we had short-term committed variable rate lines of credit in an aggregate amount of \$230.0 million. Of this amount, \$180.0 million was available for general working capital purposes and \$50.0 million was available for capital expenditures related to our generating facilities. Additionally, we have a \$50.0 million three-year revolving credit facility, which expires on March 18, 2007.

At June 30, 2005 and 2004, 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. We expect the construction-related line of credit to be renewed until such time as we determine it is not needed.

Investing Activities. Investing activities in the first six months of 2005 was 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 generation 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 second quarter of 2005.

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

FERC Proceedings Related to Potential Reorganization

On June 23, 2005, a pre-hearing conference was held regarding the applications for an amended cost-of-service formula for New Dominion Energy Cooperative's ("New Dominion") sales to the member distribution cooperatives and for the cost allocation formula for our sales to New Dominion. The parties agreed to a procedural schedule and on June 27, 2005, the presiding FERC administrative law judge issued an order adopting a procedural schedule which set the hearing for January 17, 2006, and set an initial decision due date of May 5, 2006. For further description of our legal proceedings for the FERC Proceedings Related to Potential Reorganization, see "Legal Proceedings" in Part 1, Item 3 of our 2004 Annual Report on Form 10-K.

On June 15, 2005, the judge in the U.S. Federal District Court, Eastern District of Virginia, Richmond Division, stayed the action brought by two of our member distribution cooperatives, Choptank Electric Cooperative and Delaware Electric Cooperative, against Northern Virginia Electric Cooperative pending resolution of the FERC proceedings related to the potential reorganization.

On July 26, 2005, the court denied the request of Choptank Electric Cooperative and Delaware Electric Cooperative to reconsider its stay of the action and their alternative request to appeal and established a date to discuss settlement options.

Other Matters

No material developments have occurred in our legal proceedings with Norfolk Southern Railway Company since the filing of our Annual Report on Form 10-K for the fiscal year ended December 31, 2004. No material developments have occurred in our legal proceedings with Ragnar Benson, Inc. since the filing of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2005. See "Legal Proceedings" in Part 1, Item 3 of our 2004 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 6. EXHIBITS

- 3 Amended and Restated Bylaws of Old Dominion Electric Cooperative dated as of January 1, 2005, adopted on July 26, 2005.
- 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: August 12, 2005

/s/Daniel M. Walker
Daniel M. Walker
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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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 in the design 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: August 12, 2005

 /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, Daniel M. Walker, 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 in the design 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: August 12, 2005

/s/ DANIEL M. WALKER

Daniel M. Walker
Senior Vice President and Chief Financial Officer
(Principal Financial and Accounting 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 June 30, 2005 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: August 12, 2005

/s/JACKSON E. REASOR

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

