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

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**FORM 10-Q**

(Mark One)

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

For the quarterly period ended September 30, 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

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# OLD DOMINION ELECTRIC COOPERATIVE

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**OLD DOMINION ELECTRIC COOPERATIVE  
PART 1. FINANCIAL INFORMATION**

**ITEM 1. FINANCIAL STATEMENTS  
CONDENSED CONSOLIDATED BALANCE SHEETS**

	September 30, 2006	December 31, 2005
	(in thousands)	
	(unaudited)	
<b>ASSETS:</b>		
<b>Electric Plant:</b>		
In service	\$ 1,523,523	\$ 1,519,578
Less accumulated depreciation	(501,350)	(470,735)
	1,022,173	1,048,843
Nuclear fuel, at amortized cost	9,750	9,018
Construction work in progress	16,322	16,365
Net Electric Plant	1,048,245	1,074,226
<b>Investments:</b>		
Nuclear decommissioning trust	86,472	79,464
Lease deposits	168,903	163,156
Other	47,634	12,193
Total Investments	303,009	254,813
<b>Current Assets:</b>		
Cash and cash equivalents	46,388	98,633
Deposits	-	24,686
Accounts receivable	16,459	25,242
Accounts receivable-members	79,899	80,569
Fuel, materials and supplies	30,216	25,669
Deferred energy	29,723	21,328
Prepayments	2,536	3,304
Total Current Assets	205,221	279,431
<b>Deferred Charges:</b>		
Regulatory assets	48,452	43,753
Other	24,125	60,143
Total Deferred Charges	72,577	103,896
Total Assets	\$ 1,629,052	\$ 1,712,366
<b>CAPITALIZATION AND LIABILITIES:</b>		
<b>Capitalization:</b>		
Patronage capital	\$ 280,947	\$ 271,833
Non-controlling interest	11,835	25,062
Long-term debt	835,380	832,980
Total Capitalization	1,128,162	1,129,875
<b>Current Liabilities:</b>		
Long-term debt due within one year	22,917	22,917
Accounts payable	62,920	89,854
Accounts payable-members	62,962	64,110
Accounts payable-deposits	-	24,686
Accrued expenses	47,550	33,740
Total Current Liabilities	196,349	235,307
<b>Deferred Credits and Other Liabilities:</b>		
Asset retirement obligation	50,763	48,810
Obligations under long-term leases	171,448	166,043
Regulatory liabilities	47,855	95,271
Other	34,475	37,060
Total Deferred Credits and Other Liabilities	304,541	347,184
<b>Commitments and Contingencies</b>		
Total Capitalization and Liabilities	\$ 1,629,052	\$ 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)**

	<u>Three Months Ended</u> <u>September 30,</u>		<u>Nine Months Ended</u> <u>September 30,</u>	
	<u>2006</u>	<u>2005</u>	<u>2006</u>	<u>2005</u>
	(in thousands)		(in thousands)	
Operating Revenues	\$ 221,231	\$ 207,491	\$ 610,644	\$ 539,539
Operating Expenses:				
Fuel	65,636	62,754	120,936	112,539
Purchased power	109,675	118,171	359,796	325,908
Deferred energy	339	(22,144)	(8,395)	(38,622)
Operations and maintenance	8,459	9,190	26,097	25,614
Administrative and general	7,530	10,175	24,879	25,942
Depreciation, amortization and decommissioning	9,628	9,798	28,922	29,113
Amortization of regulatory asset/(liability), net	444	175	1,137	1,348
Taxes other than income taxes	2,245	1,562	5,358	4,724
Accretion	651	618	1,953	1,854
Total Operating Expenses	<u>204,607</u>	<u>190,299</u>	<u>560,683</u>	<u>488,420</u>
Operating Margin	<u>16,624</u>	<u>17,192</u>	<u>49,961</u>	<u>51,119</u>
Other Expense, net	(16)	(76)	(84)	(202)
Investment Income	2,243	1,362	6,413	3,602
Interest Charges, net	<u>(15,306)</u>	<u>(14,717)</u>	<u>(45,376)</u>	<u>(44,033)</u>
Net Margin Before Income Taxes and Non-Controlling Interest	<u>3,545</u>	<u>3,761</u>	<u>10,914</u>	<u>10,486</u>
Income Taxes	(182)	(322)	(720)	(658)
Non-Controlling Interest	<u>(274)</u>	<u>(483)</u>	<u>(1,080)</u>	<u>(987)</u>
Net Margin	<u>3,089</u>	<u>2,956</u>	<u>9,114</u>	<u>8,841</u>
Patronage Capital - Beginning of Period	<u>277,858</u>	<u>265,609</u>	<u>271,833</u>	<u>259,724</u>
Patronage Capital - End of Period	<u>\$ 280,947</u>	<u>\$ 268,565</u>	<u>\$ 280,947</u>	<u>\$ 268,565</u>

**OLD DOMINION ELECTRIC COOPERATIVE**

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

	<u>Three Months Ended</u> <u>September 30,</u>		<u>Nine Months Ended</u> <u>September 30,</u>	
	<u>2006</u>	<u>2005</u>	<u>2006</u>	<u>2005</u>
	(in thousands)		(in thousands)	
Net Margin	\$ 3,089	\$ 2,956	\$ 9,114	\$ 8,841
Other Comprehensive Income:				
Unrealized (loss)/gain on derivative contracts <sup>(1)</sup>	(467)	28,894	(14,307)	21,850
Other Comprehensive Income Before Non-Controlling Interest	(467)	28,894	(14,307)	21,850
Less: Non-controlling interest in comprehensive income	467	(28,894)	14,307	(21,850)
Comprehensive Income	<u>\$ 3,089</u>	<u>\$ 2,956</u>	<u>\$ 9,114</u>	<u>\$ 8,841</u>

<sup>(1)</sup> Unrealized (loss)/gain on derivative contracts net of tax benefit of \$0.3 million and \$9.1 million for the three and nine months ended September 30, 2006, respectively. Unrealized (loss)/gain on derivative contracts net of tax expense of \$9.3 million \$13.9 million for the three and nine months ended September 30, 2005, respectively.

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

**OLD DOMINION ELECTRIC COOPERATIVE**

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)**

**Nine Months Ended  
September 30,**

**2006                      2005**

(in thousands)

Operating Activities:		
Net Margin	\$ 9,114	\$ 8,841
Adjustments to reconcile net margins to net cash provided by (used for) operating activities:		
Depreciation, amortization and decommissioning	28,922	29,113
Other non-cash charges	8,852	7,586
Non-controlling interest	1,080	987
Amortization of lease obligations	8,218	7,766
Interest on lease deposits	(7,965)	(7,453)
Change in current assets	30,360	(57,696)
Change in deferred energy	(8,395)	(38,622)
Change in current liabilities	(29,811)	156,558
Change in regulatory assets and liabilities	(56,090)	63,857
Deferred charges and credits	12,052	(3,830)
Net Cash (Used for)/Provided by Operating Activities	<u>(3,663)</u>	<u>167,107</u>
 Financing Activities:		
Obligations under long-term leases	<u>(595)</u>	<u>(523)</u>
Net Cash (Used for) Financing Activities	<u>(595)</u>	<u>(523)</u>
 Investing Activities:		
Purchases of available for sale securities	(57,650)	(60,693)
Proceeds from sale of available for sale securities	21,975	45,000
(Increase)/Decrease in other investments	(2,800)	435
Electric plant additions	(9,512)	(12,940)
Net Cash (Used for) Investing Activities	<u>(47,987)</u>	<u>(28,198)</u>
Net Change in Cash and Cash Equivalents	(52,245)	138,386
Cash and Cash Equivalents - Beginning of Period	98,633	17,564
Cash and Cash Equivalents - End of Period	<u>\$ 46,388</u>	<u>\$ 155,950</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 September 30, 2006, and our consolidated results of operations, comprehensive income, and cash flows for the three and nine months ended September 30, 2006 and 2005. The consolidated results of operations for the three and nine months ended September 30, 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, (“FIN 46”), 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 FIN 46. 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 \$6.2 million and \$36.1 million at September 30, 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 and nine months ended September 30, 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 September 30, 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 Electric & Power Company, ("Virginia Power"), as operator of Clover, had an initial 20-year term and provides that the amounts payable for coal transportation services are subject to adjustment based on a reference index. In October 2003, Norfolk Southern claimed that it had been using an incorrect reference index to calculate amounts due to it since the inception of the agreement, and that it would begin to escalate prices for these services in the future based on an alternate reference index. On November 26, 2003, together with Virginia Power, we filed suit against Norfolk Southern in the Circuit Court of Halifax County, Virginia, seeking an order to clarify the price escalation provisions in the coal transportation agreement. In its reply to our suit, Norfolk Southern filed a counter-claim and sought (1) recovery from Virginia Power and us for additional amounts resulting from its use of the alternate reference index since December 1, 2003, and (2) an order requiring the parties to calculate the amounts Norfolk Southern claims it was underpaid since the inception of the agreement by using the alternate reference index.

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

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.

In our legal proceeding against Norfolk Southern, the court issued an order on September 1, 2006, granting Norfolk Southern's request to substantially dispose of the issues in the case. On September 23, 2006, we timely filed, along with Virginia Power, a Notice of Appeal on the order and on September 25, 2006, we filed an appropriate Appeal Bond. Our

Petition for Appeal is due on November 30, 2006, and we intend to vigorously prosecute the appeal, if the Supreme Court of Virginia grants our Petition.

### ***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. 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.

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.

On March 27, 2006, the Marsh Run facility attained substantial completion according to the terms of the contract.

On August 4, 2006, the court ruled in our favor on all remaining issues in the case and awarded us damages of \$5.2 million plus expenses. We have not recorded any damages that have been awarded to us and will do so when they are collected. We have filed our expenses and after the court rules on our expenses and any motions RBI may file, each party will have 30 days to appeal any of the court's rulings to the United States Court of Appeals for the Fourth Circuit. We intend to enforce the court's rulings against RBI, to the extent permitted by its bankruptcy proceeding, and against Seaboard Surety Company, the surety of RBI's performance bond.

### ***Tax Increase Prevention and Reconciliation Act of 2005***

On May 17, 2006, President Bush signed into law an act entitled the "Tax Increase Prevention and Reconciliation Act of 2005" (the "2005 Tax Act"). Among other provisions, the 2005 Tax Act imposes an excise tax on certain types of leasing transactions entered into by tax-exempt entities. At this time, it is not clear whether the excise tax imposed by the 2005 Tax Act is applicable to our lease transactions. We are continuing to evaluate this legislation and the impact on us; however, specific guidance has not yet been made available. We have estimated a potential impact and have recorded a liability of approximately \$0.4 million as of September 30, 2006. However, once further guidance is issued, our potential liability under the 2005 Tax Act may change.

## **5. New Accounting Pronouncements.**

In July 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN 48"). FIN 48 prescribes a recognition threshold and measurement process for recording in the financial statements the benefit of uncertain tax positions taken or expected to be taken in a tax return. Additionally, FIN 48 provides guidance on the derecognition, classification, accounting in interim periods and disclosure requirements for uncertain tax positions. The provisions of FIN 48 become effective for fiscal years beginning after December 15, 2006. We are currently evaluating the impact of FIN 48 on our financial statements.

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

6. **Subsequent Event.** On October 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 5.2%, effective October 1, 2006. This increase was implemented due to continued increases in our energy costs and the collection of our deferred energy balance.

## OLD DOMINION ELECTRIC COOPERATIVE

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

#### **Caution Regarding Forward-Looking Statements**

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

#### **Critical Accounting Policies**

As of September 30, 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. 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, 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 and nine months ended September 30, 2006, were impacted by changing conditions in the energy markets. These changes impacted the fair value of our derivatives, purchased power costs, and our deferred energy balance for the three and nine months ended September 30, 2006. Sales of energy to non-members decreased for the three months ended September 30, 2006, and increased for the nine months ended September 30, 2006, 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. Excess energy, which is primarily sold to PJM Interconnection, LLC ("PJM"), is the result of changes in our purchased power portfolio, differences between actual and forecasted energy needs, as well as changes in market conditions.

#### **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 and nine months ended September 30, 2006 and 2005, were as follows:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
	(in thousands)		(in thousands)	
Revenues:				
Member distribution cooperatives	\$ 201,620	\$ 181,607	\$ 550,217	\$ 484,367
Non-member	19,611	25,884	60,427	55,172
Total revenues	<u>\$ 221,231</u>	<u>\$ 207,491</u>	<u>\$ 610,644</u>	<u>\$ 539,539</u>

Our energy sales in megawatt hours (“MWh”) to our members and non-members for the three months and nine months ended September 30, 2006 and 2005, were as follows:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30.</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
	(in MWh)		(in MWh)	
Energy sales:				
Member distribution cooperatives	3,122,086	3,164,270	8,366,995	8,462,122
Non-member	290,740	298,634	1,049,175	967,141
Total energy sales	<u>3,412,826</u>	<u>3,462,904</u>	<u>9,416,170</u>	<u>9,429,263</u>

**Sales to Member Distribution Cooperatives.** Revenues from sales to our member distribution cooperatives are a function of our formulary rate for sales of power to our member distribution cooperatives and our member distribution cooperatives' consumers' requirements for power. Operating revenues on our Condensed Consolidated Statements of Revenues, Expenses and Patronage Capital reflect the actual capacity-related costs we incurred plus the energy costs that we collected during the period. Estimated capacity-related costs are collected during the period through the demand component of our formulary rate. Under our formulary rate, we make adjustments for the refund or recovery of amounts under our Margin Stabilization Plan. We adjust demand revenues and accounts payable—members or accounts receivable—members each quarter to reflect these adjustments. 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 average costs to our member distribution cooperatives in MWh for the three and nine months ended September 30, 2006 and 2005, were as follows:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30.</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
	<b>(in thousands)</b>		<b>(in thousands)</b>	
Revenues from sales to member distribution cooperatives:				
Base energy revenues	\$ 56,120	\$ 56,655	\$150,480	\$151,980
Fuel factor adjustment revenues	92,109	67,503	232,707	165,512
Total energy revenues	148,229	124,158	383,187	317,492
Demand (capacity) revenues	53,391	57,449	167,030	166,875
Total revenues from sales to member distribution cooperatives	<u>\$201,620</u>	<u>\$181,607</u>	<u>\$550,217</u>	<u>\$484,367</u>
Average costs to member distribution cooperatives (per MWh) <sup>(1)</sup>	\$ 64.58	\$ 57.39	\$ 65.76	\$ 57.24

<sup>(1)</sup> 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 and Nine months Ended September 30, 2006 compared to Three and Nine months ended September 30, 2005:**

Total revenues from sales to our member distribution cooperatives for the three and nine months ended September 30, 2006, increased \$20.0 million, or 11.0%, and increased \$65.9 million, or 13.6%, respectively as compared to the same periods in 2005 as a result of our higher energy rates.

Our total energy rate (including our base energy rate and our fuel factor adjustment rate) was 21.0% and 22.1% higher during the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005. We increased our fuel factor adjustment rate effective October 1, 2005, and April 1, 2006, resulting in an increase to our total energy rate of approximately 8.1% and 11.9%, 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 September 30, 2006, as compared to the same period in 2005, decreased \$4.1 million, or 7.1%. The decrease in capacity costs related primarily to a decrease in purchased power costs and a decrease in administrative and general costs. Capacity costs for the nine months ended September 30, 2006, remained relatively flat as compared to the same period in 2005.

Our average costs to member distribution cooperatives per MWh increased \$7.19, or 12.5%, and \$8.52, or 14.9%, per MWh, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005, 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 energy to 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 the Virginia Electric & Power Company pursuant to the requirements of the Clover operating agreement. Non-member revenue decreased by \$6.3 million, or 24.2%, in the three months ended September 30, 2006, as compared to the same period in 2005. The decrease in non-member revenue is primarily due to a decrease in the average price at which we sold excess. Non-member revenue increased by \$5.3 million, or 9.5%, in the nine months ended September 30, 2006, as compared to the same period in 2005. The increase in non-member revenue for the nine months ended September 30, 2006, is primarily due to an increase in the volume of excess energy sales. Excess energy is sold at the prevailing market price at the time of sale and 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 and nine months ended September 30, 2006 and 2005, was as follows:

	Three Months Ended				Nine Months Ended			
	September 30,				September 30,			
	2006		2005		2006		2005	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	861,235	24.8 %	879,854	24.9 %	2,598,499	27.1 %	2,338,480	24.2 %
North Anna	469,832	13.6	457,806	13.0	1,298,083	13.5	1,389,300	14.4
Louisa	175,565	5.1	144,271	4.1	205,249	2.1	174,990	1.8
Marsh Run	188,726	5.4	137,400	3.9	221,420	2.3	198,473	2.1
Rock Springs	48,968	1.4	86,348	2.4	53,377	0.6	108,876	1.1
Distributed generation	606	-	1,534	-	711	-	2,171	-
Total generated	<u>1,744,932</u>	<u>50.3</u>	<u>1,707,213</u>	<u>48.3</u>	<u>4,377,339</u>	<u>45.6</u>	<u>4,212,290</u>	<u>43.6</u>
Purchased:								
Total purchased	<u>1,725,499</u>	<u>49.7</u>	<u>1,830,414</u>	<u>51.7</u>	<u>5,219,015</u>	<u>54.4</u>	<u>5,458,631</u>	<u>56.4</u>
Total available energy	<u>3,470,431</u>	<u>100.0 %</u>	<u>3,537,627</u>	<u>100.0 %</u>	<u>9,596,354</u>	<u>100.0 %</u>	<u>9,670,921</u>	<u>100.0 %</u>

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

Our operating expenses are significantly affected by the extent to which we purchase power and, relatedly, the availability of our base load generating facilities, Clover and North Anna. Base load generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs, but nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities also have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run and Rock Springs. Owners of nuclear and other power plants incur the embedded fixed costs of these facilities whether or not the units operate. When either Clover or North Anna is off-line, we must purchase replacement energy from the PJM market, which may be more or less costly. 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. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility, but are more expensive to operate; therefore, we operate them only when the market price of energy makes their operation economical or when their operation is required by PJM for system reliability purposes. 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 nine months ended September 30, 2006 and 2005, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	<b>Clover</b>				<b>North Anna</b>			
	<b>Three Months Ended</b>		<b>Nine Months Ended</b>		<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>		<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
Unit 1	90.3 %	91.5 %	91.3 %	86.3 %	99.9 %	97.6 %	86.1 %	99.8 %
Unit 2	89.1	91.5	91.0	77.8	99.5	96.5	100.0	99.2
Combined	89.7	91.5	91.2	82.1	99.7	97.1	93.1	99.5

**Clover.** During the nine months ended September 30, 2006, Clover Units 1 and 2 were each off-line for 5 days for scheduled maintenance outages. During the nine months ended September 30, 2005, Clover Units 1 and 2 were off-line for 9 days and 34 days, respectively, for scheduled maintenance outages. Clover Units 1 and 2 experienced minor unscheduled outages for the three and nine months ended September 30, 2006, and for the nine months ended September 30, 2005.

**North Anna.** During the nine months ended September 30, 2006, North Anna Unit 1 was off-line for 29 days for a scheduled refueling and maintenance outage. North Anna Unit 1 experienced minor unscheduled outages during the nine months ended September 30, 2006. North Anna Unit 2 did not experience any outages during the nine months ended September 30, 2006. North Anna Units 1 and 2 experienced minor unscheduled outages during the three and nine months ended September 30, 2005.

**Combustion turbine facilities.** During the three and nine months ended September 30, 2006, and 2005, the operational availability of Louisa, Marsh Run and Rock Springs was as follows:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
Louisa	99.5 %	98.9 %	99.6 %	97.6 %
Marsh Run	99.5	93.6	99.6	96.6
Rock Springs	100.0	97.9	93.2	97.6

On June 1, 2006, we completed the transition of the operation and maintenance of our Louisa and Marsh Run combustion turbine facilities to our own personnel.

The components of our operating expenses for the three and nine months ended September 30, 2006 and 2005, were as follows:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
	<b>(in thousands)</b>		<b>(in thousands)</b>	
Fuel	\$ 65,636	\$ 62,754	\$ 120,936	\$ 112,539
Purchased power	109,675	118,171	359,796	325,908
Deferred energy	339	(22,144)	(8,395)	(38,622)
Operations and maintenance	8,459	9,190	26,097	25,614
Administrative and general	7,530	10,175	24,879	25,942
Depreciation, amortization and decommissioning	9,628	9,798	28,922	29,113
Amortization of regulatory asset/(liability), net	444	175	1,137	1,348
Taxes, other than income taxes	2,245	1,562	5,358	4,724
Accretion	651	618	1,953	1,854
Total Operating Expenses	<u>\$ 204,607</u>	<u>\$ 190,299</u>	<u>\$ 560,683</u>	<u>\$ 488,420</u>

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 rising energy costs. Effective April 1, 2006, we decreased the demand component of our rate approximately 1.8% in accordance with the annual budget for 2006 that

our Board of Directors approved in December 2005. Increases or decreases in our budget automatically amend the demand component of our formulary rate. The increase to our total energy rate effective April 1, 2006, was not sufficient to permit us to collect all incurred energy expenses and on October 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 5.2%, effective October 1, 2006.

***Three and Nine months Ended September 30, 2006 compared to Three and Nine months ended September 30, 2005:***

Aggregate operating expenses increased \$14.3 million, or 7.5%, and \$72.3 million, or 14.8%, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005, primarily due to changes in purchased power expense, deferred energy, and fuel expense.

Purchased power expense decreased \$8.5 million, or 7.2% for the three months ended September 30, 2006, as compared to the same period in 2005 primarily due to a decrease in the volume of purchased power. Purchased power expense increased \$33.9 million, or 10.4%, for the nine months ended September 30, 2006, as compared to the same period in 2005, due to an increase in the average cost of purchased power partially offset by the decrease in the volume of purchased power. Additionally, in 2005 we had a greater portion of our purchased power costs hedged at lower prices than we did in 2006. For the three months ended September 30, 2006, the average cost of purchased power decreased 1.6% as compared to the same periods in 2005. For the nine months ended September 30, 2006, the average cost of purchased power increased 15.5% as compared to the same periods in 2005. The increase in the average cost of purchased power is reflective of the overall price increases in energy costs across all markets. For the three and nine months ended September 30, 2006, the volume of purchased power decreased 5.7% and 4.4%, respectively.

Deferred energy expense changed \$22.5 million, or 101.5%, and \$30.2 million, or 78.3%, for the three and nine months ended September 30, 2006, as compared to the same periods in 2005. During the three months ended September 30, 2006, we over-collected \$0.3 million in energy costs; whereas in the three months ended September 30, 2005, we under-collected \$22.1 million in energy costs. During the nine months ended September 30, 2006, we under-collected \$8.4 million in energy costs as compared to an under-collection of \$38.6 million for the same period in 2005. At September 30, 2006 and 2005, we had an under-collected deferred energy balance of \$29.7 million and \$33.8 million, respectively.

Fuel expense increased \$2.9 million, or 4.6%, and \$8.4 million, or 7.5%, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005. The increases in fuel expense were primarily due to increased coal costs related to generation at Clover. The average price of coal increased 18.4% and 14.2% for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005. The increase in coals costs was partially offset by a decrease in natural gas costs related to the operation of our combustion turbine facilities. Natural gas costs decreased \$1.0 million, or 2.5%, and \$6.9 million, or 13.7%, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005.

***Other Items***

***Investment Income.*** Investment income increased \$0.9 million, or 64.7%, and \$2.8 million, or 78.0%, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005, primarily due to income earned on our increased average balances in cash and temporary investments as a result of higher member prepayments and higher interest rates.

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

The major components of interest charges, net for the three and nine months ended September 30, 2006 and 2005, were as follows:

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
	<b>(in thousands)</b>		<b>(in thousands)</b>	
Interest expense on long-term debt	\$ (13,880)	\$ (14,161)	\$ (41,749)	\$ (42,546)
Other	(1,563)	(614)	(3,818)	(1,657)
Total Interest Charges	(15,443)	(14,775)	(45,567)	(44,203)
Allowance for borrowed funds used during construction	137	58	191	170
Interest Charges, net	<u>\$ (15,306)</u>	<u>\$ (14,717)</u>	<u>\$ (45,376)</u>	<u>\$ (44,033)</u>

Interest charges, net increased \$0.6 million, or 4.0%, and \$1.3 million, or 3.1%, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005. Other interest increased \$0.9 million, or 154.6% and \$2.2 million, or 130.4%, for the three and nine months ended September 30, 2006, respectively, as compared to the same periods in 2005, primarily as a result of accrued interest related to our dispute with Norfolk Southern.

**Net Margin.** Our net margin, which is a function of our total interest charges, remained relatively flat for the three and nine months ended September 30, 2006, as compared to the same period in 2005.

### Financial Condition

The principal changes in our financial condition from December 31, 2005 to September 30, 2006, were caused by decreases in regulatory liabilities, deferred charges—other, accounts payable, deposits, accounts payable—deposits, and accounts receivable. Regulatory liabilities decreased \$47.4 million primarily due to the change in the fair value of our derivatives. Deferred charges—other decreased \$36.0 million as a result of the decrease in the fair value of our derivatives. Accounts payable decreased \$26.9 million primarily as a result of decreased purchased power in September 2006 as compared to December 2005. 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 September 30, 2006, due to changes in energy prices, our counterparties were not required to post deposits as compared to December 2005. Accounts receivable decreased \$8.8 million as a result of decreased purchased power receivables, which was substantially offset by an increase of \$15.3 million related to collateral we were required to post with our counterparties.

### Liquidity and Capital Resources

**Operations.** Historically, our operating cash flows have been sufficient to meet our short- and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. During the first nine months of 2006, our cash needs exceeded our cash flows from operating activities by \$3.7 million. Our operating activities provided cash flow of \$167.1 million during the first nine months of 2005. Operating activities during the first nine months of 2006 were primarily impacted by the change in regulatory assets and liabilities, current liabilities, and deferred energy partially offset by the change in current assets. Regulatory assets and liabilities changed \$56.1 million primarily due to the change in the fair value of our derivatives. Current liabilities changed \$29.8 million primarily as a result of decreased accounts payable related to purchased power 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. At September 30, 2006, we had an under-collected deferred energy balance of \$29.7 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 \$8.4 million. Current assets changed \$30.4 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. The change in current assets also related to the decrease in accounts receivable which was primarily due to the decrease in purchased power receivables, substantially offset by an increase of \$15.3 million related to collateral we were required to post with our counterparties.

**Financing Activities.** In addition to liquidity from our operating activities, we maintain committed lines of credit and revolving credit facilities to cover short-term and medium-term funding needs. As of September 30, 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 purposes. One of these revolving credit facilities expires on March 18, 2007 and the other expires on January 30, 2009.

At September 30, 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 and revolving credit facilities to be renewed as they expire.

***Investing Activities.*** Investing activities in the first nine 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 third 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**

In the proceedings before FERC relative to the complaint of Northern Virginia Electric Cooperative (“NOVEC”) against our Wholesale Power Contract, on August 24, 2006, FERC issued an Order Denying Rehearing, upholding its March 2, 2006, Order Denying Complaint. NOVEC subsequently filed a Petition for Review of FERC’s Order Denying Rehearing in the U.S. Court of Appeals for the District of Columbia Circuit on October 20, 2006. We plan to intervene in the case and will participate in the appeal process. For further description of our legal proceedings for NOVEC, see Part 1, Item 3 of our 2005 Annual Report on Form 10-K.

##### **Norfolk Southern**

In our legal proceeding against Norfolk Southern Railway Company (“Norfolk Southern”), the court issued an order on September 1, 2006, granting Norfolk Southern’s request to substantially dispose of the issues in the case. On September 23, 2006, we timely filed, along with Virginia Electric & Power Company, a Notice of Appeal on the order and on September 25, 2006, we filed an appropriate Appeal Bond. Our Petition for Appeal is due on November 30, 2006, and we intend to vigorously prosecute the appeal, if the Supreme Court of Virginia grants our Petition.

##### **Other Matters**

No material developments have occurred in our legal proceedings with Ragnar Benson, Inc. or FERC Proceedings Related to Potential Reorganization, since the filing of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006. See “Legal Proceedings” in Part II, Item 1 of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006. 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 6. EXHIBITS

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



## EXHIBIT INDEX

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

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

I, Jackson E. Reasor, certify that:

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

**Date: November 13, 2006**

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





