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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 June 30, 2010

or

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission file 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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).  
Yes  No

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "larger accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Larger accelerated filer  Accelerated filer   
Non-accelerated filer  Smaller reporting company

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

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**

	<b>June 30, 2010</b>	<b>December 31, 2009</b>
	(in thousands)	
	(unaudited)	
<b>ASSETS:</b>		
Electric Plant		
In service	\$ 1,592,624	\$ 1,578,459
Less accumulated depreciation	(646,570)	(630,600)
	<u>946,054</u>	<u>947,859</u>
Nuclear fuel, at amortized cost	16,412	13,519
Construction work in progress	62,017	46,995
Net Electric Plant	<u>1,024,483</u>	<u>1,008,373</u>
Investments:		
Nuclear decommissioning trust	85,341	85,437
Lease deposits	88,333	87,052
Unrestricted investments and other	3,954	3,587
Total Investments	<u>177,628</u>	<u>176,076</u>
Current Assets:		
Cash and cash equivalents	40,228	6,278
Accounts receivable	5,209	264
Accounts receivable – deposits	4,500	3,800
Accounts receivable – members	85,188	72,716
Fuel, materials and supplies	44,226	49,290
Prepayments and other	3,103	3,521
Total Current Assets	<u>182,454</u>	<u>135,869</u>
Deferred Charges:		
Regulatory assets	118,620	97,864
Other	19,806	21,730
Total Deferred Charges	<u>138,426</u>	<u>119,594</u>
Total Assets	<u>\$ 1,522,991</u>	<u>\$ 1,439,912</u>
<b>CAPITALIZATION AND LIABILITIES:</b>		
Capitalization:		
Patronage capital	\$ 334,094	\$ 329,520
Non-controlling interest	13,152	13,178
Total Patronage capital and Non-controlling interest	<u>347,246</u>	<u>342,698</u>
Long-term debt	473,725	688,736
Total Capitalization	<u>820,971</u>	<u>1,031,434</u>
Current Liabilities		
Long-term debt due within one year	237,917	22,917
Lines of credit	-	26,954
Accounts payable	84,992	48,966
Accounts payable – members	66,500	29,004
Interest rate hedge	21,191	-
Accrued expenses	6,061	4,659
Deferred energy	52,491	38,740
Total Current Liabilities	<u>469,152</u>	<u>171,240</u>
Deferred Credits and Other Liabilities		
Asset retirement obligations	66,194	64,543
Obligations under long-term leases	62,705	60,612
Regulatory liabilities	88,092	96,456
Other	15,877	15,627
Total Deferred Credits and Other Liabilities	<u>232,868</u>	<u>237,238</u>
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	<u>\$ 1,522,991</u>	<u>\$ 1,439,912</u>

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

**OLD DOMINION ELECTRIC COOPERATIVE**  
**CONDENSED CONSOLIDATED STATEMENTS OF REVENUES,**  
**EXPENSES AND PATRONAGE CAPITAL (UNAUDITED)**

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Operating Revenues	\$ 184,063	\$ 168,938	\$ 359,720	\$ 371,660
Operating Expenses				
Fuel	39,829	27,969	68,252	58,809
Purchased power	92,433	82,203	183,957	196,777
Deferred energy	5,680	8,062	13,751	14,022
Operations and maintenance	9,463	12,436	18,361	26,028
Administrative and general	10,184	9,856	22,789	19,215
Depreciation, amortization and decommissioning	10,343	10,240	20,677	20,483
Amortization of regulatory asset/(liability), net	732	68	1,699	(206)
Accretion of asset retirement obligations	842	817	1,651	1,635
Taxes, other than income taxes	2,229	2,009	4,310	4,038
Total Operating Expenses	171,735	153,660	335,447	340,801
Operating Margin	12,328	15,278	24,273	30,859
Other Expense, net	(429)	(442)	(871)	(882)
Investment Income	1,051	697	2,347	1,047
Interest Charges, net	(10,570)	(12,666)	(21,208)	(25,352)
Income Taxes	1	(114)	7	(197)
Net Margin Including Non-controlling Interest	2,381	2,753	4,548	5,475
Non-controlling Interest	2	(170)	26	(321)
Net Margin Attributable to Old Dominion Electric Cooperative	2,383	2,583	4,574	5,154
Patronage Capital—Beginning of Period	331,711	322,404	329,520	319,833
Patronage Capital—End of Period	\$ 334,094	\$ 324,987	\$ 334,094	\$ 324,987

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

**OLD DOMINION ELECTRIC COOPERATIVE**  
**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)**

	<b>Six Months Ended</b>	
	<b>June 30,</b>	
	<b>2010</b>	<b>2009</b>
	(in thousands)	
<b>Operating Activities:</b>		
Net Margin	\$ 4,574	\$ 5,154
Adjustments to reconcile net margins to net cash provided by operating activities:		
Depreciation, amortization and decommissioning	20,677	20,483
Other non-cash charges	5,033	4,817
Non-controlling interest	(26)	321
Amortization of lease obligations	2,093	2,737
Interest on lease deposits	(1,281)	(1,920)
Change in current assets	(12,635)	12,903
Change in deferred energy	13,751	14,022
Change in current liabilities	74,924	(24,353)
Change in regulatory assets and liabilities	(6,259)	(7,100)
Change in deferred charges and credits	2,717	(258)
Net Cash Provided by Operating Activities	<u>\$ 103,568</u>	<u>\$ 26,806</u>
<b>Financing Activities:</b>		
Obligations under long-term leases	-	(236)
Draws on lines of credit	84,632	351,167
Repayment on lines of credit	(111,586)	(364,593)
Net Cash Used for Financing Activities	<u>(26,954)</u>	<u>(13,662)</u>
<b>Investing Activities:</b>		
Increase in other investments	(1,940)	(415)
Electric plant additions	(40,724)	(20,332)
Net Cash Used for Investing Activities	<u>(42,664)</u>	<u>(20,747)</u>
Net Change in Cash and cash equivalents	33,950	(7,603)
Cash and cash equivalents—Beginning of Period	6,278	12,025
Cash and cash equivalents—End of Period	<u>\$ 40,228</u>	<u>\$ 4,422</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, 2010, and our consolidated results of operations, and cash flows for the three and six months ended June 30, 2010 and 2009. The consolidated results of operations for the three and six months ended June 30, 2010, 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 2009 Annual Report on Form 10-K filed with the Securities and Exchange Commission.
2. *Presentation.* The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative (“ODEC” or “we” or “our”) and TEC Trading, Inc. (“TEC”). We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our Class A members are eleven 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.

We do not have any other comprehensive income for the periods presented.

In accordance with Consolidation accounting, TEC is considered a variable interest entity for which we are the primary beneficiary. We have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the net assets consolidated were \$13.2 million at June 30, 2010, and December 31, 2009. The income taxes reported on our Statement of Revenues, Expenses and Patronage Capital relate to the tax provision for TEC. As TEC is 100% owned by our Class A members, its equity is presented as a non-controlling interest in our consolidated financial statements.

Our rates are set periodically by a formula that was accepted for filing by the Federal Energy Regulatory Commission (“FERC”), but are not regulated by the respective states’ public service commissions.

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.

Certain reclassifications have been made to the prior years’ consolidated financial statements to conform to the current year’s presentation.

3. *Fair Value Measurements.*

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

The following table summarizes our financial assets and liabilities measured at fair value on a recurring basis (at least annually) as of June 30, 2010 and December 31, 2009:

	<b>June 30, 2010</b>	<b>Quoted Prices in Active Markets for Identical Assets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>
		(in thousands)		
Nuclear decommissioning trust <sup>(1)</sup>	\$ 85,341	\$ 85,341	\$ -	\$ -
Unrestricted investments and other <sup>(2)(3)</sup>	2,233	51	-	2,182
Total Financial Assets	<u>\$ 87,574</u>	<u>\$ 85,392</u>	<u>\$ -</u>	<u>\$ 2,182</u>
Derivatives – gas and power <sup>(4)</sup>	\$ 7,700	\$ 7,700	\$ -	\$ -
Derivative – interest rate hedge <sup>(5)</sup>	21,191	-	21,191	-
Total Financial Liabilities	<u>\$ 28,891</u>	<u>\$ 7,700</u>	<u>\$ 21,191</u>	<u>\$ -</u>

  

	<b>December 31, 2009</b>	<b>Quoted Prices in Active Markets for Identical Assets (Level 1)</b>	<b>Significant Other Observable Inputs (Level 2)</b>	<b>Significant Unobservable Inputs (Level 3)</b>
		(in thousands)		
Nuclear decommissioning trust <sup>(1)</sup>	\$ 85,437	\$ 85,437	\$ -	\$ -
Unrestricted investments and other <sup>(2)(3)</sup>	1,869	56	-	1,813
Total Financial Assets	<u>\$ 87,306</u>	<u>\$ 85,493</u>	<u>\$ -</u>	<u>\$ 1,813</u>
Derivatives – gas/power <sup>(4)</sup>	\$ 6,904	\$ 6,152	\$ 752	\$ -
Total Financial Liabilities	<u>\$ 6,904</u>	<u>\$ 6,152</u>	<u>\$ 752</u>	<u>\$ -</u>

- (1) For additional information about our nuclear decommissioning trust see Note 7 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.
- (2) Unrestricted investments and other includes investments that were available for sale and classified as level 1 related to equity securities.
- (3) Unrestricted investments and other includes investments that were available for sale and classified as level 3. As of June 30, 2010 and December 31, 2009, we had \$17.3 million of principal invested in six auction rate security investments and preferred stock (“ARS”). As of June 30, 2010 and December 31, 2009, we had an unrealized loss of \$15.1 million and \$15.5 million, respectively, related to these ARS which was recorded as a regulatory asset in accordance with Accounting for Regulated Operations. For additional information, see Notes 7 and 8 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.
- (4) Derivatives – gas and power represent natural gas futures contracts and purchased power contracts. For additional information about our derivative financial instruments, refer to Notes 1 and 4 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.
- (5) Derivative – interest rate hedge represents the fair value of the interest rate hedge. On May 14, 2010, we entered into an interest rate hedge with an initial notional amount of \$300.0 million and a settlement rate tied to the 30-year U.S. Treasury bond. At June 30, 2010, the fair value of this interest rate hedge was a liability of \$21.2 million, which is recorded on our balance sheet as a current liability.

The following table presents the net change in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category for the six months ended June 30, 2010:

	<b>Six Months Ended June 30, 2010</b>
	(in thousands)
Balance at January 1, 2010	\$ 1,813
Total realized and unrealized gain:	
Included in regulatory and other assets/liabilities	369
Purchases, issuances and settlements	-
Transfers out of Level 3	-
Balance at June 30, 2010	<u>\$ 2,182</u>

The unrealized gain (change in market value) was reported in regulatory assets in our Consolidated Balance Sheet as of June 30, 2010.

4. *Derivatives and Hedging:*

We are exposed to market purchases of power and natural gas to meet the power supply needs of our member distribution cooperatives that are not met by our owned generation. In addition, we are exposed to fluctuations in long-term interest rates related to our issuance and refunding of long-term debt. To manage this exposure, we utilize derivative contracts. See Note 1 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

Changes in the fair value of our derivative instruments are recorded as a regulatory asset or regulatory liability. The change in these accounts is included in the operating section of our statement of cash flows.

Excluding contracts accounted for as normal purchase/normal sale, we had the following outstanding natural gas futures contracts and purchased power contracts:

<u>Commodity</u>	<u>Unit of Measure</u>	<u>As of June 30, 2010 Quantity</u>	<u>As of December 31, 2009 Quantity</u>
Natural gas	MMBTU	4,040,000	4,910,000
Purchased power-excess sales	MWh	68,800	108,935
Renewable energy credits	REC	70,000	-
Interest rate hedge	US Dollars	300,000,000	-

The fair value of our derivative instruments, excluding contracts accounted for as normal purchase/normal sale, was as follows:

**Fair Value of Derivative Instruments**

<u>Balance Sheet Location</u>		<u>Fair Value</u>	
		<u>As of June 30, 2010</u>	<u>As of December 31, 2009</u>
<b>Derivatives in an asset position designated as hedging instruments:</b>			
Purchased power-excess sales	Prepayments and other	\$ 78	\$ -
Renewable energy credit sales	Prepayments and other	382	-
<b>Total derivatives in an asset position designated as hedging instruments</b>		<u>\$ 460</u>	<u>\$ -</u>
<b>Derivatives in a liability position designated as hedging instruments:</b>			
Natural gas futures contracts	Deferred credits and other liabilities-other	\$ 7,700	\$ 6,152
Interest rate hedge	Interest rate hedge	21,191	-
Purchased power contracts	Deferred credits and other liabilities-other	-	752
<b>Total derivatives in a liability position designated as hedging instruments</b>		<u>\$ 28,891</u>	<u>\$ 6,904</u>

**The Effect of Derivative Instruments on the Statement of Revenues, Expenses and Patronage Capital  
for the Three and Six Months Ended June 30, 2010 and June 30, 2009**

<b>Derivatives Accounted for Utilizing Regulatory Accounting</b>	<b>Amount of Gain (Loss) Recognized within Regulatory Asset/Liability for Derivatives as of June 30, Dec. 31,</b>		<b>Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income</b>	<b>Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Quarter Ended June 30,</b>		<b>Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Six Months Ended June 30,</b>	
	<u>2010</u>	<u>2009</u>		<u>2010</u>	<u>2009</u>	<u>2010</u>	<u>2009</u>
	(in thousands)			(in thousands)		(in thousands)	
Natural gas futures contracts <sup>(1)</sup>	\$ (8,551)	\$ (21,710)	Fuel/Purchased power	\$ (392)	\$ (6,197)	\$ (1,440)	\$ (9,083)
Purchased power-excess sales <sup>(2)</sup>	697	-	Operating revenue	-	-	-	-
Purchased power	-	-	Purchased power	-	-	(365)	-
Renewable energy credit sales	382	-	Operating revenue	-	-	-	-
Interest rate hedge	(21,191)	-	Interest charges, net	-	-	-	-
Total	<u>\$(28,663)</u>	<u>\$ (21,710)</u>		<u>\$ (392)</u>	<u>\$ (6,197)</u>	<u>\$ (1,805)</u>	<u>\$ (9,083)</u>

- <sup>(1)</sup> Gain (loss) related to natural gas futures contracts is recorded in fuel and purchased power. Includes \$851,600 of loss on contracts designated for July 2010 that were physically sold in June and the impact on the Statement of Financial Position has been deferred until July 2010.
- <sup>(2)</sup> Includes option premium of \$619,200 related to July and August 2010 sales and the impact on the Statement of Financial Position has been deferred until July and August 2010.

Our hedging activities expose us to credit-related risks. We use hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. Because we rely substantially on the purchase of energy from other power suppliers, we are exposed to the risk that counterparties will default in performance of their obligations to us. Although we assess the creditworthiness of counterparties and other credit issues related to these purchases, and we may require our counterparties to post collateral with us, defaults may still occur. Defaults may take the form of failure to physically deliver the purchased energy or failure to pay. If this occurs, we may be forced to enter into alternative contractual arrangements or purchase energy in the forward, short-term or spot markets at then-current market prices that may be more or less than the prices previously agreed upon with the defaulting counterparty.

5. *Investments:*

Investments were as follows at June 30, 2010 and December 31, 2009:

<u>Description</u>	<u>Designation</u>	<u>Cost</u>	<u>Gross Unrealized Gains</u>	<u>Gross Unrealized Losses</u>	<u>Fair Value</u>	<u>Carrying Value</u>
<b>June 30, 2010</b>						
Nuclear decommissioning trust <sup>(1)</sup>						
Debt securities	Available for sale	\$ 40,459	\$ 160	\$ -	\$ 40,619	\$ 40,619
Equity securities	Available for sale	47,389	1,275	(3,974)	44,690	44,690
Cash and other	Available for sale	32	-	-	32	32
Total Nuclear decommissioning trust		<u>\$ 87,880</u>	<u>\$ 1,435</u>	<u>\$ (3,974)</u>	<u>\$ 85,341</u>	<u>\$ 85,341</u>
Lease deposits <sup>(2)</sup>						
Government obligations	Held to maturity	\$ 88,333	\$ 1,070	\$ -	\$ 89,403	\$ 88,333
Total Lease deposits		<u>\$ 88,333</u>	<u>\$ 1,070</u>	<u>\$ -</u>	<u>\$ 89,403</u>	<u>\$ 88,333</u>
Unrestricted investments <sup>(3)</sup>						
Debt securities	Available for sale	\$ 2,137	\$ -	\$ -	\$ 2,137	\$ 2,137
Equity securities	Available for sale	45	-	-	45	45
Total Unrestricted investments		<u>\$ 2,182</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 2,182</u>	<u>\$ 2,182</u>
Other						
Equity securities	Available for sale	\$ 63	\$ -	\$ (11)	\$ 52	\$ 52
Non-marketable equity investments	Equity	1,720	-	-	1,720	1,720
Total Other		<u>\$ 1,783</u>	<u>\$ -</u>	<u>\$ (11)</u>	<u>\$ 1,772</u>	<u>\$ 1,772</u>
					Total Carrying Value	<u>\$ 177,628</u>
<b>December 31, 2009</b>						
Nuclear decommissioning trust <sup>(1)</sup>						
Debt securities	Available for sale	\$ 39,289	\$ -	\$ (2,020)	\$ 37,269	\$ 37,269
Equity securities	Available for sale	46,577	3,661	(2,142)	48,096	48,096
Cash and other	Available for sale	72	-	-	72	72
Total Nuclear decommissioning trust		<u>\$ 85,938</u>	<u>\$ 3,661</u>	<u>\$ (4,162)</u>	<u>\$ 85,437</u>	<u>\$ 85,437</u>
Lease deposits <sup>(2)</sup>						
Government obligations	Held to maturity	\$ 87,052	\$ 138	\$ (7,213)	\$ 79,977	\$ 87,052
Total Lease deposits		<u>\$ 87,052</u>	<u>\$ 138</u>	<u>\$ (7,213)</u>	<u>\$ 79,977</u>	<u>\$ 87,052</u>
Unrestricted investments <sup>(4)</sup>						
Debt securities	Available for sale	\$ 1,761	\$ -	\$ -	\$ 1,761	\$ 1,761
Equity securities	Available for sale	52	-	-	52	52
Total Unrestricted investments		<u>\$ 1,813</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 1,813</u>	<u>\$ 1,813</u>
Other						
Equity securities	Available for sale	\$ 62	\$ -	\$ (6)	\$ 56	\$ 56
Non-marketable equity investments	Equity	1,718	-	-	1,718	1,718
Total Other		<u>\$ 1,780</u>	<u>\$ -</u>	<u>\$ (6)</u>	<u>\$ 1,774</u>	<u>\$ 1,774</u>
					Total Carrying Value	<u>\$ 176,076</u>

(1) Investments in the nuclear decommissioning trust are restricted for the use of funding our share of the asset retirement obligations of the future decommissioning of the North Anna Power Station. See Note 3 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K. Realized and unrealized gains and losses related to assets held in the nuclear decommissioning trust are deferred as a regulatory asset or liability.

(2) Investments in lease deposits are restricted for the use of funding our future lease obligations. See Note 6 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

(3) The cost represents investments in ARS with a par value of \$28.8 million, that have been written down by \$26.6 million due to the \$11.5 million recognition of a loss and the \$15.1 million unrealized loss. We have deferred the \$15.1 million as a regulatory asset in accordance with Accounting for Regulated Operations. See Note 8 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

(4) The cost represents investments in ARS with a par value of \$28.8 million, net of a \$5.0 million par value redemption in 2009 that resulted in a \$1.4 million recognized loss. The cost has been written down by \$27.0 million due to the \$11.5 million recognition of a loss and the \$15.5 million unrealized loss. We have deferred the \$15.5 million as a regulatory asset in accordance with Accounting for Regulated Operations. See Note 8 of the Notes to Consolidated Financial Statements in our 2009 Annual Report on Form 10-K.

Contractual maturities of unrestricted debt securities at June 30, 2010, were as follows:

<u>Description</u>	<u>Less than 1 year</u>	<u>1-5 years</u>	<u>5-10 years</u>	<u>More than 10 years</u>	<u>Total</u>
	(in thousands)				
Available for Sale	\$ -	\$ -	\$ -	\$ 2,137	\$ 2,137
Held to Maturity	-	-	-	-	-
	<u>\$ -</u>	<u>\$ -</u>	<u>\$ -</u>	<u>\$ 2,137</u>	<u>\$ 2,137</u>

6. *Subsequent Event.* In July 2010, we acquired a tract of land in Sussex County, Virginia, as a possible site for a future generation facility for a purchase price of \$14.4 million.

## 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, demand for energy, federal and state legislative and regulatory actions and legal and administrative proceedings, changes in and compliance with environmental laws and policies, general credit and capital market conditions, 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, 2010, there have been no significant changes in our critical accounting policies as disclosed in our 2009 Annual Report on Form 10-K. These policies include the accounting for rate regulation, deferred energy, margin stabilization plan, and accounting for asset retirement obligations and derivative contracts.

#### Basis of Presentation

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

#### Overview

ODEC is a not-for-profit power supply cooperative owned entirely by its eleven Class A member distribution cooperatives and a Class B 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 six months ended June 30, 2010, were significantly impacted by:

- Unseasonably warm weather in May and June which increased our member distribution cooperatives requirements for power resulting in increased dispatch of our combustion turbine facilities,
- Acquisition of additional service territory by two of our member distribution cooperatives,
- Reduction in our total energy rate, and
- Entry into an interest rate hedge transaction.

#### Member Distribution Cooperatives—Acquisition of Additional Service Territory

On June 1, 2010, two of our member distribution cooperatives, Rappahannock Electric Cooperative ("REC") and Shenandoah Valley Electric Cooperative ("SVEC"), acquired the distribution assets and right to provide electric distribution services to approximately 102,000 customers (meters) previously owned by The Potomac Edison Company in Virginia ("Potomac Edison"). We estimate REC's and SVEC's acquisitions will increase our megawatt hour ("MWh") and megawatt ("MW") sales to our member distribution cooperatives by approximately 35 to 40% on an annualized basis.

In accordance with the wholesale power contracts between ODEC and its member distribution cooperatives, ODEC will serve the additional power requirements resulting from REC's and SVEC's acquisitions. We were not a party to this transaction; however, we assumed power supply contracts previously entered into by Potomac Edison for the service territory to serve the load of these customers. These contracts expire on June 30, 2011. A valuation of these contracts was performed as of June 1, 2010, and the value of the contracts approximated a fair value of zero.

In accordance with our load acquisition policy, we will pay a transition fee to REC and to SVEC that represents a portion of the projected power cost savings related to these acquisitions. The aggregate transition fee is approximately \$66.7 million and approximately \$1.4 million was recorded in the second quarter of 2010. The transition fee will be reflected as a credit on the monthly power invoices to REC and SVEC over 48 months as a reduction in sales and is being collected from our member distribution cooperatives through our formulary rate.

**Results of Operations**

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

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

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

The formulary rate has three main components: a demand rate, a base energy rate and a fuel factor adjustment rate. The formulary rate identifies the cost components that we can collect through rates, but not the actual amounts to be collected. With limited minor exceptions, we can change our rates periodically to match the costs we have incurred and we expect to incur without seeking FERC approval. For further discussion on our formulary rate, see Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results – Formulary Rate in our 2009 Annual Report on Form 10-K.

**Operating Revenues.** Our operating revenues are derived from power sales to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the three and six months ended June 30, 2010 and 2009, were as follows:

	<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2010</b>	<b>2009</b>	<b>2010</b>	<b>2009</b>
	(in thousands)		(in thousands)	
Revenue from sales to:				
Member distribution cooperatives	\$ 168,082	\$ 157,129	\$ 343,118	\$ 350,387
Non-members	15,981	11,809	16,602	21,273
Total revenues	<u>\$ 184,063</u>	<u>\$ 168,938</u>	<u>\$ 359,720</u>	<u>\$ 371,660</u>

**Energy and Demand Sales Volumes.** Our energy sales in MWh to our member distribution cooperatives and non-members for the three and six months ended June 30, 2010 and 2009, were as follows:

	<b>Three Months Ended</b>		<b>Six Months Ended</b>	
	<b>June 30,</b>		<b>June 30,</b>	
	<b>2010</b>	<b>2009</b>	<b>2010</b>	<b>2009</b>
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	2,321,776	1,843,402	4,797,457	4,286,240
Non-members	345,043	388,877	364,447	611,888
Total energy sales	<u>2,666,819</u>	<u>2,232,279</u>	<u>5,161,904</u>	<u>4,898,128</u>

Our energy sales in MWh to our member distribution cooperatives were 26.0% and 11.9% higher for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009, primarily as a result of the service territory acquisition of two of our member distribution cooperatives as of June 1, 2010 and changes in weather. The additional service

territory increased our energy sales in MWh to our member distribution cooperatives approximately 15.0% and 6.5% for the three and six months ended June 30, 2010, respectively. During the May and June of 2010, we experienced unseasonably warm weather.

Our energy sales in MWh to non-members were 11.3% and 40.4% lower for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009. Sales to non-members consist of sales of excess purchased and generated energy.

Our demand sales in megawatts (“MW”) to our member distribution cooperatives for the three and six months ended June 30, 2010 and 2009, were as follows:

	<b>Three Months Ended June 30,</b>		<b>Six Months Ended June 30,</b>	
	<b>2010</b>	<b>2009</b>	<b>2010</b>	<b>2009</b>
	(in MW)		(in MW)	
Demand sales to member distribution cooperatives	<u>4,595</u>	<u>3,586</u>	<u>9,416</u>	<u>9,040</u>

Our demand sales in MW to our member distribution cooperatives were 28.1% and 4.2% higher for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009, primarily as a result of additional service territory of two of our member distribution cooperatives and changes in the weather. The additional service territory increased our demand sales in MW to our member distribution cooperatives approximately 14.5% and 5.5% for the three and six months ended June 30, 2010, respectively. During the May and June of 2010, we experienced unseasonably warm weather which was partially offset by milder weather experienced in the first quarter of 2010.

**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 2009 Annual Report on Form 10-K. Growth in the number of consumers and growth in consumers’ requirements for power significantly affect our member distribution cooperatives’ requirements for power. Factors affecting our member distribution cooperatives’ consumers’ requirements for power include weather, the economy, and residential and commercial growth. See “Consumers Requirements for Power” in Part II, Item 7, of our 2009 Annual Report on Form 10-K.

Revenues from sales to our member distribution cooperatives by formulary rate component and our average costs to our member distribution cooperatives in MWh for the three and six months ended June 30, 2010 and 2009, were as follows:

	<b>Three Months Ended June 30,</b>		<b>Six Months Ended June 30,</b>	
	<b>2010</b>	<b>2009</b>	<b>2010</b>	<b>2009</b>
	(in thousands)		(in thousands)	
Revenue from sales to member distribution cooperatives:				
Base energy revenues	\$ 41,312	\$ 32,912	\$ 85,525	\$ 76,538
Fuel factor adjustment revenues	<u>60,690</u>	<u>64,278</u>	<u>129,686</u>	<u>154,350</u>
Total energy revenues	102,002	97,190	215,211	230,888
Demand (capacity) revenues	<u>66,080</u>	<u>59,939</u>	<u>127,907</u>	<u>119,499</u>
Total Revenues	<u>\$ 168,082</u>	<u>\$ 157,129</u>	<u>\$ 343,118</u>	<u>\$ 350,387</u>
Average costs to member distribution cooperatives (per MWh)	\$ 72.39	\$ 85.24	\$ 71.52	\$ 81.75

Total revenues from sales to our member distribution cooperatives for the three months ended June 30, 2010, increased \$11.0 million, or 7.0%, as compared to the same period in 2009. The increase in total revenues for the three months ended June 30, 2010, is related to the additional service territory and weather-related increases in our energy sales volumes, partially offset by a lower total energy rate. Total revenues from sales to our member distribution cooperatives for the six months ended June 30, 2010, decreased \$7.3 million, or 2.1%, as compared to the same period in 2009 primarily due to the lower total energy rate partially offset by an increase in energy sales volumes.

Our total energy rate (including base energy rate and fuel factor adjustment rate) was \$8.79, or 16.7% and \$9.01, or 16.7%, lower on a per MWh basis for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009.

The following table summarizes the changes to our total energy rate as a result of changes to our fuel factor adjustment rate:

<u>Effective Date of Rate Change:</u>	<u>% Change (Decrease)</u>
January 1, 2009	(8.2)
April 1, 2009	(3.7)
August 1, 2009	(5.7)
October 1, 2009	(8.0)
April 1, 2010	(3.8)

These decreases are due to the continued reduction in our realized as well as projected energy costs due to overall reduced energy costs.

The capacity costs we incurred, and thus the capacity-related revenues we reflected pursuant to the formulary rate, increased \$6.1 million, or 10.2%, and \$8.4 million, or 7.0%, for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009, due to higher purchased power capacity costs and administrative and general costs, offset by lower operations and maintenance expense and net interest expense.

Our average costs to member distribution cooperatives decreased \$12.85 per MWh, or 15.1%, and \$10.23, or 12.5%, for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009, as a result of decreases in our total energy rate slightly offset by higher capacity 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. Non-member revenue increased by \$4.2 million or 35.3%, and decreased by \$4.7 million, or 22.0%, in the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009. For the three months ended June 30, 2010, the increase is due to an increase in the prices at which we sold excess energy to non-members partially offset by a decrease in the volume of excess energy sales. The volume of excess energy sales decreased 11.3% for the three months ended June 30, 2010, as compared to the same period in 2009. For the six months ended June 30, 2010, the decrease is due to a 40.4% decrease in the volume of excess energy sales partially offset by an increase in the prices at which we sold excess energy to non-members. Excess energy is sold at the prevailing market price at the time of the sale and is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, as well as changes in market conditions.

**Power Supply Resources**

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 the Clover Power Station (“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 six months ended June 30, 2010 and 2009, was as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	757,151	28.0%	621,556	27.6%	1,617,575	31.0%	1,348,210	27.3%
North Anna	366,518	13.6	456,168	20.2	796,247	15.3	853,711	17.3
Louisa	95,874	3.5	9,658	0.4	105,651	2.0	26,372	0.5
Marsh Run	137,936	5.1	7,851	0.4	150,728	2.9	26,637	0.5
Rock Springs	52,864	2.0	7,551	0.3	54,279	1.0	7,844	0.2
Distributed generation	337	-	4	-	339	-	7	-
Total generated	<u>1,410,680</u>	<u>52.2</u>	<u>1,102,788</u>	<u>48.9</u>	<u>2,724,819</u>	<u>52.2</u>	<u>2,262,781</u>	<u>45.8</u>
Purchased:								
Total purchased	<u>1,293,422</u>	<u>47.8</u>	<u>1,153,230</u>	<u>51.1</u>	<u>2,494,555</u>	<u>47.8</u>	<u>2,676,083</u>	<u>54.2</u>
Total available energy	<u>2,704,102</u>	<u>100.0%</u>	<u>2,256,018</u>	<u>100.0%</u>	<u>5,219,374</u>	<u>100.0%</u>	<u>4,938,864</u>	<u>100.0%</u>

We satisfy the majority of our capacity requirements and approximately half of our 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 generally have relatively higher fixed costs but relatively lower variable costs. When either Clover or North Anna is off-line, we purchase replacement energy from either Virginia Electric and Power Company or from the market. As a result, our operating expenses, and consequently our rates to our member distribution cooperatives, are more significantly affected by the operations of Clover and North Anna than by our combustion turbine facilities. Our combustion turbine facilities have relatively lower fixed costs and greater operational flexibility; however, they have relatively higher variable costs; and as a result we will operate them only when the market price of energy makes their operation economical or when their operation is required by PJM Interconnection, LLC for system reliability purposes.

The output of Clover and North Anna for the three and six months ended June 30, 2010 and 2009, as a percentage of the maximum net dependable capacity rating of the facilities was as follows:

	Clover				North Anna			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009	2010	2009	2010	2009
Unit 1	78.4%	88.9%	85.1%	82.7%	102.0%	99.6%	100.6%	86.8%
Unit 2	81.6	42.6	86.5	60.6	62.0	100.3	72.6	100.8
Combined	80.0	65.8	85.8	71.7	82.0	100.0	86.6	93.8

The scheduled and unscheduled outages for Clover for the three and six months ended June 30, 2010 and 2009, were as follows:

	Scheduled Outages				Unscheduled Outages			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009	2010	2009	2010	2009
	(in days)				(in days)			
Unit 1	8.0	-	8.0	14.0	1.8	1.9	1.9	2.9
Unit 2	7.8	42.1	7.8	53.1	-	3.5	0.4	3.5
Combined	<u>15.8</u>	<u>42.1</u>	<u>15.8</u>	<u>67.1</u>	<u>1.8</u>	<u>5.4</u>	<u>2.3</u>	<u>6.4</u>

The scheduled and unscheduled outages for North Anna for the three and six months ended June 30, 2010 and 2009, were as follows:

	Scheduled Outages				Unscheduled Outages			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009	2010	2009	2010	2009
	(in days)		(in days)		(in days)		(in days)	
Unit 1	-	1.2	-	25.1	-	-	-	-
Unit 2	25.3	-	36.3	-	11.1	-	11.1	-
Combined	25.3	1.2	36.3	25.1	11.1	-	11.1	-

**Combustion turbine facilities.** During the three and six months ended June 30, 2010 and 2009, the operational availability of our Louisa, Marsh Run and Rock Springs combustion turbine facilities was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Louisa	98.7%	97.6%	99.3%	98.4%
Marsh Run	94.9	100.0	97.4	99.4
Rock Springs	87.9	97.7	93.5	94.1

### Operating Expenses

The components of our operating expenses for the three and six months ended June 30, 2010 and 2009, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)		(in thousands)	
Fuel	\$ 39,829	\$ 27,969	\$ 68,252	\$ 58,809
Purchased power	92,433	82,203	183,957	196,777
Deferred energy	5,680	8,062	13,751	14,022
Operations and maintenance	9,463	12,436	18,361	26,028
Administrative and general	10,184	9,856	22,789	19,215
Depreciation, amortization and decommissioning	10,343	10,240	20,677	20,483
Amortization of regulatory asset/(liability), net	732	68	1,699	(206)
Accretion of asset retirement obligations	842	817	1,651	1,635
Taxes other than income taxes	2,229	2,009	4,310	4,038
Total Operating Expenses	\$ 171,735	\$ 153,660	\$ 335,447	\$ 340,801

Aggregate operating expenses increased \$18.1 million, or 11.8%, for the three months ended June 30, 2010, as compared to the same period in 2009 primarily due to the increase in fuel expense and purchased power expense slightly offset by a decrease in operations and maintenance expense and deferred energy.

- Fuel expense increased \$11.9 million, or 42.4%, primarily due to the increase in the dispatch of our combustion turbine facilities.
- Purchased power expense increased \$10.2 million, or 12.4%, due to a 12.2% increase in the volume of purchased power related to the additional service territory partially offset by a decrease in the volume of purchased power due to our owned generation resources supplying 52.2% of our members power needs in 2010 versus 48.9% in 2009.
- Operations and maintenance expense decreased \$3.0 million, or 23.9%, as a result of differences in scheduled maintenance and refueling outages at Clover and North Anna during 2010 as compared to 2009.
- Deferred energy expense decreased \$2.4 million, or 29.5%. During the three months ended June 30, 2010, we over-collected \$5.7 million in energy costs; whereas in the three months ended June 30, 2009, we over-collected \$8.1 million in energy costs.

Aggregate operating expenses decreased by \$5.4 million, or 1.6%, for the six months ended June 30, 2010, as compared to the same period in 2009. The decrease was primarily due to the decrease in purchased power expense and operations and maintenance expense partially offset by the increase in fuel expense.

- Purchased power expense decreased \$12.8 million, or 6.5%, primarily due to changes in our purchased power needs. For the six months ended June 30, 2010, our owned generation resources supplied 52.2% of our member distribution cooperatives power needs versus 45.8% in 2009. This was partially offset by an increase in the volume of purchased power related to the additional service territory.
- Operations and maintenance expense decreased \$7.7 million, or 29.5% as a result of differences in scheduled maintenance and refueling outages at Clover and North Anna during 2010 as compared to 2009.
- Fuel expense increased \$9.4 million, or 16.1%, due to the increase in the dispatch of our combustion turbine facilities. This increase was slightly offset by decreased coal costs at Clover as a result of the amortization of the regulatory liability associated with the Norfolk Southern dispute settlement partially offset by higher coal consumption at Clover.

**Other Items**

**Investment Income.** Investment income increased \$0.4 million, or 50.8%, and \$1.3 million, or 124.2%, for the three and six months ended June 30, 2010, respectively, as compared to the same periods in 2009, primarily due to higher investment balances.

**Interest Charges, net.** The primary factors affecting our interest expense are scheduled annual payments of principal on our indebtedness, interest charges related to our dispute with Norfolk Southern Railway Company (“Norfolk Southern”), interest charges related to our credit facilities, and capitalized interest. We settled a dispute with Norfolk Southern in 2009. For further discussion of our dispute with Norfolk Southern, see Item 3 Legal Proceedings and Item 7 Management’s Discussion and Analysis of Financial Condition and Results of Operations see – Financial Condition in our 2009 Annual Report on Form 10-K.

The major components of interest charges, net for the three and six months ended June 30, 2010 and 2009, were as follows:

	<b>Three Months Ended June 30,</b>		<b>Six Months Ended June 30,</b>	
	<b>2010</b>	<b>2009</b>	<b>2010</b>	<b>2009</b>
	(in thousands)		(in thousands)	
Interest expense on long-term debt	\$ (11,588)	\$ (11,930)	\$ (23,167)	\$ (23,851)
Interest charges related to Norfolk Southern <sup>(1)</sup>	819	(895)	2,080	(1,377)
Other	(217)	(90)	(849)	(541)
Total Interest Charges	(10,986)	(12,915)	(21,936)	(25,769)
Allowance for borrowed funds used during construction	416	249	728	417
Interest Charges, net	<u>\$(10,570)</u>	<u>\$ (12,666)</u>	<u>\$ (21,208)</u>	<u>\$ (25,352)</u>

<sup>(1)</sup> In 2010, includes amortization of the regulatory liability related to settlement of a dispute with Norfolk Southern. In 2009, includes interest charge related to potential liability associated with the dispute.

**Net Margin.** Our net margin, which is a function of our total interest charges plus any equity contributions, decreased \$0.2 million, or 7.7% and \$0.6 million, or 11.3% for the three and six months ended June 30, 2010 as compared to the same periods in 2009. On June 29, 2010, our board of directors approved an equity contribution of \$1.3 million for 2010 to be collected June 1, 2010 to December 31, 2010. The three and six months ended June 30, 2010 includes \$0.2 million of equity contribution.

**Financial Condition**

The principal changes in our financial condition from December 31, 2009 to June 30, 2010, were caused by increases in long-term debt due within one year, accounts payable–members, accounts payable, interest rate hedge, regulatory assets, deferred energy, and accounts receivable–members, partially offset by decreases in long-term debt and lines of credit.

- Long-term debt due within one year increased \$215.0 million due to the maturity of our 2001 Series A Bonds on June 1, 2011.

- Accounts payable—members increased \$37.5 million due to higher member prepayments as compared to December 2009.
- Accounts payable increased \$36.0 million due to increased purchased power and natural gas.
- Interest rate hedge increased \$21.2 million. To mitigate a portion of our exposure to fluctuations in long-term interest rates we entered into an interest rate hedge on May 14, 2010, with an initial notional amount of \$300.0 million related to the 30-year U.S. Treasury bond. The liability is due to the interest rate on 30-year U.S. Treasury bonds decreasing after we executed the transaction.
- Regulatory assets increased \$20.8 million primarily related to the interest rate hedge described above.
- Deferred energy changed \$13.8 million due to the over-collection of energy costs in 2010.
- Accounts receivable—members increased \$12.5 million as a result of higher sales in June 2010 as compared to December 2009, primarily related to the additional service territory of two of our member distribution cooperatives (see “Member Distribution Cooperative – Acquisition of Additional Service Territory”).
- Long-term debt decreased \$215.0 million due to the maturity of our 2001 Series A Bonds on June 1, 2011.
- Amounts outstanding under our lines of credit decreased \$27.0 million reflecting our repayment of all amounts outstanding under our lines of credit.

## Liquidity and Capital Resources

**Operations.** Historically, our operating cash flows generally have been sufficient to meet our short-term and long-term capital expenditures related to our existing generating facilities, our debt service requirements, and our ordinary business operations. During the first six months of 2010 and 2009, our operating activities provided cash flow of \$103.6 million and \$26.8 million, respectively. Operating activities in the first six months of 2010 were primarily impacted by changes in current liabilities, deferred energy and current assets.

- Current liabilities changed \$74.9 million primarily related to the \$37.5 million increase in accounts payable—members and the \$36.0 million increase in accounts payable, partially offset by the \$27.0 million decrease in lines of credit.
- Deferred energy changed by \$13.8 million due to the over-collection of energy costs.
- Current assets changed \$12.6 million primarily related to the \$12.5 million increase in the accounts receivable—members balance, the \$4.9 million increase in accounts receivable, partially offset by the \$5.1 million decrease in fuel, materials and supplies.

**Financing Activities.** In addition to liquidity from our operating activities, we currently maintain a total of \$390.0 million in committed lines of credit and revolving credit facilities to cover short-term and medium-term funding needs. As of June 30, 2010, we had short-term committed variable rate lines of credit in an aggregate amount of \$145.0 million. Additionally, we had committed revolving credit facilities totaling \$245.0 million. At June 30, 2010 we had no short-term borrowings or letters of credit outstanding under any of these arrangements. At December 31, 2009, we had \$27.0 million of short-term borrowings outstanding under these arrangements. During the second quarter of 2010, we increased our three-year revolving credit facility with CoBank, ACB from \$75.0 million to \$100.0 million and extended the maturity to June 18, 2013. We renewed our \$70.0 million line of credit with JPMorgan Chase Bank, N.A. and extended the maturity to June 1, 2012.

Our short-term committed variable rate lines of credit are as follows:

<u>Lender</u>	<u>Amount</u> (in millions)	<u>Expiration Date</u>
Bank of America, N.A.	\$ 70.0	September 29, 2010
Branch Banking and Trust Company	25.0	April 30, 2011
Wachovia, National Association.	50.0	September 28, 2010
	<u>\$ 145.0</u>	

Our committed revolving credit facilities are as follows:

<u>Lender</u>	<u>Amount</u>	<u>Expiration Date</u>
	(in millions)	
CoBank, ACB	\$100.0	June 18, 2013
JPMorgan Chase Bank, National Association	70.0	June 1, 2012
National Rural Utilities Cooperative Finance Corp.	75.0	April 15, 2012
	<u>\$ 245.0</u>	

**Investing Activities.** Investing activities in the first three months of 2010 were primarily impacted by activity related to electric plant additions for our generating facilities, and interest earned on investments—unrestricted investments and other, and cash and cash equivalents.

**Interest Rate Hedge.** We are exposed to fluctuations in long-term interest rates related to the issuance of long-term debt and refunding of \$215.0 million principal amount of our 2001 Series A Bonds that mature on June 1, 2011. To mitigate a portion of this exposure, on May 14, 2010, we entered into an interest rate hedge with an initial notional amount of \$300.0 million and a settlement rate tied to the 30-year U.S. Treasury bond. At June 30, 2010, the fair value of this interest rate hedge was a \$21.2 million liability, and is recorded as a current liability on our balance sheet.

**Auction Rate Securities.** As of June 30, 2010 and December 31, 2009, we had \$17.3 million of principal invested in six securities, all of which were originally issued as auction rate securities and two of which have converted to preferred stock, (“ARS”). The estimated fair value of our ARS was \$2.2 million as of June 30, 2010, and was \$1.8 million as of December 31, 2009.

ARS pay variable rates of interest which reset periodically in connection with the auction to purchase or sell the securities. Generally, the periodic auctions provide owners of ARS the opportunity to liquidate their investment at par value. In the event auctions are not fully subscribed, which auction agents describe as failed auctions, these securities are typically illiquid.

In the absence of liquidity provided by auctions, we rely on a third party to establish the estimated fair values of our ARS. It is our understanding that the estimated fair values of our ARS are determined with a valuation model that utilizes expected cash flow streams, assessments of credit quality, discount rates, and overall credit market liquidity, among other things.

The following represents changes in our ARS principal, fair value, and unrealized loss for the six months ended June 30, 2010:

	<u>Principal</u>	<u>Fair Value</u>	<u>Unrealized Loss</u> <sup>(2)</sup>
	(in thousands)		
ARS at December 31, 2009 <sup>(1)</sup>	\$ 17,320	\$ 1,813	\$15,507
ARS at June 30, 2010 <sup>(1)</sup>	\$ 17,320	\$ 2,182	\$15,138

<sup>(1)</sup> Recorded on Consolidated Balance Sheet in Investments–Unrestricted investments and other, and are classified as available for sale.

<sup>(2)</sup> Recorded on Consolidated Balance Sheet in Deferred Charges–Regulatory assets.

The cumulative \$15.1 million difference between the principal of our ARS and the estimated fair value of our ARS at June 30, 2010, was accounted for as a regulatory asset in accordance with Accounting for Regulated Operations. Future changes in the estimated fair value of our ARS will be accounted for in a similar manner.

## **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 2010.

### **ITEM 4. CONTROLS AND PROCEDURES**

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

# **OLD DOMINION ELECTRIC COOPERATIVE**

## **PART II. OTHER INFORMATION**

### **ITEM 1. LEGAL PROCEEDINGS**

#### **Other Matters**

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, 2009, 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

**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 11, 2010

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

## 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

**CERTIFICATIONS**

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 quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
  - (a) designed such disclosure controls and procedures or caused such disclosure controls 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 quarterly report is being prepared;
  - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date 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
  - (d) 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;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, 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 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 11, 2010

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

## CERTIFICATIONS

I, Robert L. Kees, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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-15e and 15d-15e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
  - (a) designed such disclosure controls and procedures or caused such disclosure controls 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 quarterly report is being prepared;
  - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date 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
  - (d) 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;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation, 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 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 11, 2010

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

**OLD DOMINION ELECTRIC COOPERATIVE**  
**CERTIFICATION PURSUANT TO**  
**18 U.S.C. SECTION 1350,**  
**AS ADOPTED 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, 2010 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 result of operations of the Company.

Date: August 11, 2010

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

**OLD DOMINION ELECTRIC COOPERATIVE**  
**CERTIFICATION PURSUANT TO**  
**18 U.S.C. SECTION 1350,**  
**AS ADOPTED 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, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert L. Kees, Senior Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

Date: August 11, 2010

\_\_\_\_\_  
/s/ROBERT L. KEES

Robert L. Kees  
Senior Vice President and Chief Financial Officer  
(Principal financial officer)