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

# FORM 10-Q

**(Mark One)**

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

**For the quarterly period ended September 30, 2016**

**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**<br>**(State or other jurisdiction of incorporation or organization)** | **23-7048405**<br>**(I.R.S. employer identification no.)** |
| **4201 Dominion Boulevard, Glen Allen, Virginia**<br>**(Address of principal executive offices)** | **23060**<br>**(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.

**GLOSSARY OF TERMS**

The following abbreviations or acronyms used in this Form 10-Q are defined below:

| Abbreviation or Acronym | Definition |
|---|---|
| ACES | Alliance for Cooperative Energy Services Power Marketing, LLC |
| Alstom | Alstom Power, Inc. |
| Bear Island | Bear Island Paper WB LLC |
| Clover | Clover Power Station |
| CPCN | Certificate of Public Convenience and Necessity |
| EPC | Engineering, procurement, and construction |
| FERC | Federal Energy Regulatory Commission |
| GAAP | Accounting principles generally accepted in the United States |
| Mitsubishi | Mitsubishi Hitachi Power Systems Americas, Inc. |
| MPSC | Maryland Public Service Commission |
| MW | Megawatt(s) |
| MWh | Megawatt hour(s) |
| North Anna | North Anna Nuclear Power Station |
| ODEC, We, Our | Old Dominion Electric Cooperative |
| PJM | PJM Interconnection, LLC |
| REC | Rappahannock Electric Cooperative |
| RTO | Regional transmission organization |
| TEC | TEC Trading, Inc. |
| VSCC | Virginia State Corporation Commission |
| Wildcat Point | Wildcat Point Generation Facility |
| XBRL | Extensible Business Reporting Language |

**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, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| | (unaudited) | |
| ASSETS: | | |
| Electric Plant: | | |
| Property, plant, and equipment | $ 1,744,164 | $ 1,722,477 |
| Less accumulated depreciation | (846,994) | (821,947) |
| Net Property, plant, and equipment | 897,170 | 900,530 |
| Nuclear fuel, at amortized cost | 16,239 | 15,720 |
| Construction work in progress | 704,730 | 541,323 |
| Net Electric Plant | 1,618,139 | 1,457,573 |
| Investments: | | |
| Nuclear decommissioning trust | 156,370 | 145,715 |
| Lease deposits | 103,759 | 101,816 |
| Unrestricted investments and other | 7,070 | 7,093 |
| Total Investments | 267,199 | 254,624 |
| Current Assets: | | |
| Cash and cash equivalents | 564 | 58,383 |
| Accounts receivable | 14,885 | 10,960 |
| Accounts receivable–deposits | — | 1,200 |
| Accounts receivable–members | 82,624 | 83,248 |
| Fuel, materials, and supplies | 53,526 | 63,829 |
| Prepayments and other | 3,173 | 4,683 |
| Total Current Assets | 154,772 | 222,303 |
| Deferred Charges: | | |
| Regulatory assets | 51,606 | 61,073 |
| Other | 1,060 | 6,026 |
| Total Deferred Charges | 52,666 | 67,099 |
| Total Assets | $ 2,092,776 | $ 2,001,599 |
| CAPITALIZATION AND LIABILITIES: | | |
| Capitalization: | | |
| Patronage capital | $ 399,875 | $ 390,976 |
| Non-controlling interest | 5,711 | 5,704 |
| Total Patronage capital and Non-controlling interest | 405,586 | 396,680 |
| Long-term debt | 1,018,263 | 1,017,926 |
| Revolving credit facility | 80,250 | — |
| Total long-term debt and revolving credit facility | 1,098,513 | 1,017,926 |
| Total Capitalization | 1,504,099 | 1,414,606 |
| Current Liabilities: | | |
| Long-term debt due within one year | 28,292 | 28,292 |
| Accounts payable | 115,745 | 109,887 |
| Accounts payable–members | 72,508 | 98,462 |
| Accrued expenses | 23,252 | 5,580 |
| Deferred energy | 48,811 | 27,835 |
| Total Current Liabilities | 288,608 | 270,056 |
| Deferred Credits and Other Liabilities: | | |
| Asset retirement obligations | 121,772 | 118,200 |
| Obligations under long-term lease | 95,352 | 90,622 |
| Regulatory liabilities | 81,216 | 73,702 |
| Other | 1,729 | 34,413 |
| Total Deferred Credits and Other Liabilities | 300,069 | 316,937 |
| Commitments and Contingencies | — | — |
| Total Capitalization and Liabilities | $ 2,092,776 | $ 2,001,599 |

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 September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| | (in thousands) | | (in thousands) | |
| Operating Revenues | $222,802 | $254,265 | $678,410 | $795,862 |
| Operating Expenses: | | | | |
| Fuel | 47,337 | 48,717 | 111,925 | 127,945 |
| Purchased power | 86,320 | 95,339 | 306,601 | 391,772 |
| Transmission | 30,008 | 29,456 | 92,368 | 84,614 |
| Deferred energy | 10,562 | 31,481 | 20,976 | 33,175 |
| Operations and maintenance | 13,100 | 10,750 | 38,277 | 39,584 |
| Administrative and general | 10,843 | 9,702 | 31,638 | 30,193 |
| Depreciation and amortization | 11,686 | 11,456 | 34,854 | 33,657 |
| Amortization of regulatory asset/(liability), net | 608 | 835 | 685 | 2,421 |
| Accretion of asset retirement obligations | 1,212 | 1,161 | 3,633 | 3,533 |
| Taxes, other than income taxes | 2,104 | 2,071 | 6,323 | 6,263 |
| Total Operating Expenses | 213,780 | 240,968 | 647,280 | 753,157 |
| Operating Margin | 9,022 | 13,297 | 31,130 | 42,705 |
| Other expense, net | (887) | (801) | (2,836) | (2,489) |
| Investment income | 1,712 | 1,542 | 3,177 | 4,498 |
| Interest charges, net | (6,856) | (11,035) | (22,562) | (35,815) |
| Income taxes | — | 1 | (3) | (1) |
| Net Margin including Non-controlling interest | 2,991 | 3,004 | 8,906 | 8,898 |
| Non-controlling interest | — | 1 | (7) | (7) |
| Net Margin attributable to ODEC | 2,991 | 3,005 | 8,899 | 8,891 |
| Patronage Capital - Beginning of Period | 396,884 | 384,983 | 390,976 | 379,097 |
| Patronage Capital - End of Period | $399,875 | $387,988 | $399,875 | $387,988 |

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, 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Operating Activities: | | |
| Net Margin including Non-controlling interest | $ 8,906 | $ 8,898 |
| Adjustments to reconcile net margin to net cash provided by operating activities: | | |
| Depreciation and amortization | 34,854 | 33,657 |
| Other non-cash charges | 13,739 | 13,881 |
| Amortization of lease obligations | 4,730 | 4,418 |
| Interest on lease deposits | (2,229) | (2,174) |
| Change in current assets | 9,712 | (21,899) |
| Change in deferred energy | 20,976 | 33,175 |
| Change in current liabilities | (19,774) | 75,756 |
| Change in regulatory assets and liabilities | 8,796 | 3,969 |
| Change in deferred charges-other and deferred credits and other liabilities-other | 1,406 | 6,425 |
| Net Cash Provided by Operating Activities | 81,116 | 156,106 |
| Investing Activities: | | |
| Purchases of held to maturity securities | — | (130,000) |
| Proceeds from sale of held maturity securities | — | 130,000 |
| Increase in other investments | (2,152) | (3,769) |
| Electric plant additions | (217,033) | (223,695) |
| Net Cash Used for Investing Activities | (219,185) | (227,464) |
| Financing Activities: | | |
| Issuance of long-term debt | — | 332,000 |
| Debt issuance costs | — | (1,754) |
| Draws on revolving credit facility | 177,850 | 104,000 |
| Repayments on revolving credit facility | (97,600) | (190,000) |
| Net Cash Provided by Financing Activities | 80,250 | 244,246 |
| Net Change in Cash and Cash Equivalents | (57,819) | 172,888 |
| Cash and Cash Equivalents - Beginning of Period | 58,383 | 1,424 |
| Cash and Cash Equivalents - End of Period | $ 564 | $ 174,312 |

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

**OLD DOMINION ELECTRIC COOPERATIVE**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

*1. General*

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. In the opinion of 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, 2016, our consolidated results of operations for the three and nine months ended September 30, 2016 and 2015, and cash flows for the nine months ended September 30, 2016 and 2015. The consolidated results of operations for the three and nine months ended September 30, 2016, 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 2015 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative and 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 customers located in Virginia, Delaware, and Maryland. 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 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 consolidated assets were $5.7 million at September 30, 2016 and December 31, 2015. The income taxes reported on our Condensed Consolidated Statement of Revenues, Expenses, and Patronage Capital relate to the tax provision for TEC. As TEC is wholly-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 FERC, but are not regulated by the respective public service commissions of the states in which our member distribution cooperatives operate. See Note 5—Other—FERC Proceeding Related to Formula Rate below.

We comply with the Uniform System of Accounts as prescribed by FERC. In conformity with 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.

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

As a result of the adoption of Accounting Standards Update 2015-03 Interest-Imputation of Interest (Subtopic 835-30), we have reclassified debt issuance costs from deferred charges-other to long-term debt in the prior year's Condensed Consolidated Balance Sheet to conform to the current year's presentation.

*2. 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 as of September 30, 2016 and December 31, 2015:

| | September 30, 2016 | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Observable Inputs (Level 3) |
|---|---|---|---|---|
| | | (in thousands) | | |
| Nuclear decommissioning trust [1] | $ 49,074 | $ 49,074 | $ — | $ — |
| Nuclear decommissioning trust - net asset value [1][2] | 107,296 | — | — | — |
| Unrestricted investments and other [3] | 237 | — | 237 | — |
| Derivatives - gas and power [4] | 842 | 842 | — | — |
| Total Financial Assets | $ 157,449 | $ 49,916 | $ 237 | $ — |
| | | | | |
| Derivatives - gas and power [4] | $ 138 | $ - | $ 138 | $ — |
| Total Financial Liabilities | $ 138 | $ - | $ 138 | $ — |

| | December 31, 2015 | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Observable Inputs (Level 3) |
|---|---|---|---|---|
| | | (in thousands) | | |
| Nuclear decommissioning trust [1] | $ 46,051 | $ 46,051 | $ — | $ — |
| Nuclear decommissioning trust - net asset value [1][2] | 99,664 | — | — | — |
| Unrestricted investments and other [3] | 211 | — | 211 | — |
| Total Financial Assets | $ 145,926 | $ 46,051 | $ 211 | $ — |
| | | | | |
| Derivatives - gas and power [4] | $ 3,653 | $ 3,653 | $ — | $ — |
| Total Financial Liabilities | $ 3,653 | $ 3,653 | $ — | $ — |

(1) For additional information about our nuclear decommissioning trust see Note 4 below.
(2) Nuclear decommissioning trust includes investments measured at net asset value per share (or its equivalent) as a practical expedient and these investments have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Condensed Consolidated Balance Sheet.
(3) Unrestricted investments and other includes investments that are related to equity securities.
(4) Derivatives - gas and power represent natural gas futures contracts. Level 1 are indexed against NYMEX. Level 2 are valued by ACES using observable market inputs for similar transactions. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K.

We did not have any financial assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category.

3. *Derivatives and Hedging*

We are exposed to market price risk by purchasing power to supply the power requirements of our member distribution cooperatives that are not met by our owned generation. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk. To manage this exposure, we utilize derivative instruments. See Note 1 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K.

Changes in the fair value of our derivative instruments accounted for at fair value are recorded as a regulatory asset or regulatory liability. The change in these accounts is included in the operating activities section of our Condensed Consolidated Statements of Cash Flows.

Excluding contracts accounted for as normal purchase/normal sale, we had the following outstanding derivative instruments:

| Commodity | Unit of Measure | As of September 30, 2016 Quantity | As of December 31, 2015 Quantity |
|---|---|---|---|
| Natural Gas | MMBTU | 8,430,000 | 10,620,000 |

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

| | Balance Sheet Location | Fair Value As of September 30, 2016 | Fair Value As of December 31, 2015 |
|---|---|---|---|
| | | (in thousands) | |
| **Derivatives in an asset position:** | | | |
| Natural gas futures contracts | Deferred charges-other | $ 842 | $ — |
| **Total derivatives in an asset position** | | $ 842 | $ — |
| **Derivatives in a liability position:** | | | |
| Natural gas futures contracts | Deferred credits and other liabilities-other | $ 138 | $ 3,653 |
| **Total derivatives in a liability position** | | $ 138 | $ 3,653 |

**The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three and Nine Months Ended September 30, 2016 and 2015**

| Derivatives Accounted for Utilizing Regulatory Accounting | Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of September 30, 2016 | 2015 | Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income | Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Three Months Ended September 30, 2016 | 2015 | Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Nine Months Ended September 30, 2016 | 2015 |
|---|---|---|---|---|---|---|---|
| | (in thousands) | | | (in thousands) | | (in thousands) | |
| Natural gas futures contracts | $ 704 | $ (2,530) | Fuel | $ 77 | $ (4,079) | $ (2,421) | $ (5,737) |
| Purchased power contracts | — | — | Purchased Power | — | — | — | (14) |
| Total | $ 704 | $ (2,530) | Total | $ 77 | $ (4,079) | $ (2,421) | $ (5,751) |

Our hedging activities expose us to credit-related risks. We use hedging instruments, including forwards, futures, financial transmission rights, and options, to mitigate our power market price risks. Because we rely substantially on the use of hedging instruments, 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 hedging instruments, 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 purchased energy or failure to pay. If a default 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 exceed the prices previously agreed upon with the defaulting counterparty.

4. *Investments*

Investments were as follows as of September 30, 2016 and December 31, 2015:

| Description | Designation | Cost | Gross Unrealized Gains | Gross Unrealized Losses | Fair Value | Carrying Value |
|---|---|---|---|---|---|---|
| | | | | (in thousands) | | |
| **September 30, 2016** | | | | | | |
| Nuclear decommissioning trust [1] | | | | | | |
| Debt securities | Available for sale | $ 43,814 | $ 5,156 | $ — | $ 48,970 | $ 48,970 |
| Equity securities | Available for sale | 73,876 | 33,442 | (22) | 107,296 | 107,296 |
| Cash and other | Available for sale | 104 | — | — | 104 | 104 |
| Total Nuclear Decommissioning Trust | | $ 117,794 | $ 38,598 | $ (22) | $ 156,370 | $ 156,370 |
| Lease Deposits [2] | | | | | | |
| Government obligations | Held to maturity | $ 103,759 | $ 4,097 | $ — | $ 107,856 | $ 103,759 |
| Total Lease Deposits | | $ 103,759 | $ 4,097 | $ — | $ 107,856 | $ 103,759 |
| Unrestricted investments | | | | | | |
| Government obligations | Held to maturity | $ 2,001 | $ 3 | $ — | $ 2,004 | $ 2,001 |
| Debt securities | Held to maturity | 2,689 | 18 | — | 2,707 | 2,689 |
| Total Unrestricted Investments | | $ 4,690 | $ 21 | $ — | $ 4,711 | $ 4,690 |
| Other | | | | | | |
| Equity securities | Trading | $ 191 | $ 46 | $ — | $ 237 | $ 237 |
| Non-marketable equity investments | Equity | 2,143 | 2,082 | — | 4,225 | 2,143 |
| Total Other | | $ 2,334 | $ 2,128 | $ — | $ 4,462 | $ 2,380 |
| | | | | | | $ 267,199 |
| **December 31, 2015** | | | | | | |
| Nuclear decommissioning trust [1] | | | | | | |
| Debt securities | Available for sale | $ 42,898 | $ 2,940 | $ — | $ 45,838 | $ 45,838 |
| Equity securities | Available for sale | 72,213 | 29,164 | (1,713) | 99,664 | 99,664 |
| Cash and other | Available for sale | 213 | — | — | 213 | 213 |
| Total Nuclear Decommissioning Trust | | $ 115,324 | $ 32,104 | $ (1,713) | $ 145,715 | $ 145,715 |
| Lease Deposits [2] | | | | | | |
| Government obligations | Held to maturity | $ 101,816 | $ 4,428 | $ — | $ 106,244 | $ 101,816 |
| Total Lease Deposits | | $ 101,816 | $ 4,428 | $ — | $ 106,244 | $ 101,816 |
| Unrestricted investments | | | | | | |
| Government obligations | Held to maturity | $ 2,003 | $ — | $ (2) | $ 2,001 | $ 2,003 |
| Debt securities | Held to maturity | 2,689 | — | (5) | 2,684 | 2,689 |
| Total Unrestricted Investments | | $ 4,692 | $ — | $ (7) | $ 4,685 | $ 4,692 |
| Other | | | | | | |
| Equity securities | Trading | $ 175 | $ 36 | $ — | $ 211 | $ 211 |
| Non-marketable equity investments | Equity | 2,190 | 1,978 | — | 4,168 | 2,190 |
| Total Other | | $ 2,365 | $ 2,014 | $ — | $ 4,379 | $ 2,401 |
| | | | | | | $ 254,624 |

[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 North Anna. See Note 3 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K. Unrealized gains and losses related to assets held in the nuclear decommissioning trust are deferred as a regulatory asset or liability, respectively.

[2] Investments in lease deposits are restricted for the use of funding our future lease obligations. See Note 8 of the Notes to Consolidated Financial Statements in our 2015 Annual Report on Form 10-K.

Our investments by classification as of September 30, 2016 and December 31, 2015, were as follows:

| Description | September 30, 2016 Cost | September 30, 2016 Carrying Value | December 31, 2015 Cost | December 31, 2015 Carrying Value |
|---|---|---|---|---|
| | (in thousands) | | (in thousands) | |
| Available for sale | $ 117,794 | $ 156,370 | $ 115,324 | $ 145,715 |
| Held to maturity | 108,449 | 108,449 | 106,508 | 106,508 |
| Equity | 2,143 | 2,143 | 2,190 | 2,190 |
| Trading | 191 | 237 | 175 | 211 |
| Total | $ 228,577 | $ 267,199 | $ 224,197 | $ 254,624 |

Contractual maturities of debt securities as of September 30, 2016, were as follows:

| Description | Less than 1 year | 1-5 years | 5-10 years | More than 10 years | Total |
|---|---|---|---|---|---|
| | | | (in thousands) | | |
| Available for sale (1) | $ — | $ — | $ 48,970 | $ — | $ 48,970 |
| Held to maturity | 3,532 | 104,917 | — | — | 108,449 |
| Total | $ 3,532 | $ 104,917 | $ 48,970 | $ — | $ 157,419 |

(1) The contractual maturities of available for sale debt securities are measured using the effective duration of the bond fund within the nuclear decommissioning trust.

*5. Other*

*Wildcat Point Generation Facility*

We are currently constructing, and will be the sole owner of, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor and permanent construction began in January 2015. We currently anticipate that the project cost will be approximately $834.3 million, including capitalized interest. On September 14, 2016, a transformer at Wildcat Point caught fire. The fire was contained and extinguished, and did not present an environmental hazard. There was no other damage to the facility and no loss is expected to be recorded. The facility is still scheduled to become operational in mid-2017.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. In June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through September 30, 2016, we capitalized construction costs related to Wildcat Point totaling $670.0 million, including $34.3 million of capitalized interest.

*FERC Proceeding Related to Formula Rate*

On September 30, 2013, we filed with FERC to revise our cost-based formula rate in order to more closely align our cost recovery from our member distribution cooperatives with the methodologies used by PJM to allocate costs to us. On November 8, 2013, Bear Island, a customer of REC, filed a motion to intervene, protest, and request for hearing. On December 2, 2013, FERC issued its order accepting the proposed revisions for filing to become effective January 1, 2014, subject to refund, and establishing hearing and settlement procedures. We received an initial decision from the hearing judge on April 13, 2015. The hearing judge found many components of the formula rate to be just and reasonable. We believe all components of the formula rate are just and reasonable and addressed the components the hearing judge found to be unjust and unreasonable in our brief on exceptions. Briefs on exceptions to the initial decision and briefs opposing exceptions to the initial decision were filed in 2015. The FERC commissioners have the ultimate authority in this proceeding and they have no timetable to issue a final order. Our formula rate remains in effect subject to refund pending a final order from FERC. If a refund is ultimately determined, we believe it will result in a reallocation of costs among our member distribution cooperatives.

*Recovery of Costs from PJM*

On June 23, 2014, we filed a petition at FERC seeking recovery from PJM of approximately $14.9 million of unreimbursed costs, which were incurred during the first quarter of 2014 related to the dispatch of our combustion turbine generating facilities. On June 9, 2015, FERC denied our petition, on July 9, 2015, we filed a request for rehearing, and on August 10, 2015, FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. On March 1, 2016, FERC denied our request for rehearing and on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit. We have not recorded a receivable related to this matter.

*Revolving Credit Facility*

We maintain a $500.0 million revolving credit facility to cover our short-term and medium-term funding needs that are not met by cash from operations or other available funds. Commitments under this syndicated credit agreement extend until March 5, 2019. At September 30, 2016, we had $80.3 million outstanding under this facility. At December 31, 2015, we did not have any borrowings outstanding under this facility. At September 30, 2016 and December 31, 2015, we had letters of credit outstanding in the amount of $5.2 million and $8.2 million, respectively.

*Limited Exception under Wholesale Power Contracts*

We have a wholesale power contract with each of our member distribution cooperatives. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions. One of the limited exceptions permits the member distribution cooperative to receive up to the greater of 5% of its power requirements or 5 MW from owned generation or other suppliers. As of March 31, 2016, our member distribution cooperatives collectively received approximately 9 MW under this exception. Beginning May 1, 2016, our member distribution cooperatives collectively receive approximately 60 MW under this exception. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows.

*Retail Choice in Virginia*

In Virginia, retail choice in the selection of a power supplier is available to customers that consume at least 5 MW of power individually or in the aggregate (with aggregation subject to the approval of the VSCC) and that do not account for more than 1% of the incumbent utility's peak load during the past year. Currently, no customer of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Beginning June 1, 2016, Bear Island, an industrial customer of REC and the only customer of any of our member distribution cooperatives that has noncoincident peak demand that exceeds 90 MW, elected to purchase its power requirements from an alternate supplier. During 2015, Bear Island represented approximately 3.3% of our revenues from our member distribution cooperatives. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows.

*New Accounting Pronouncements*

We adopted Accounting Standards Update 2015-03 Interest-Imputation of Interest (Subtopic 835-30) for the fiscal year beginning January 1, 2016. Debt issuance costs related to a recognized debt liability are presented on our Condensed Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. Debt issuance costs were previously presented as an asset in deferred charges-other on our Condensed Consolidated Balance Sheet. We have reclassified debt issuance costs in the prior year's Condensed Consolidated Balance Sheet to conform to the current year's presentation. Debt issuance costs related to a recognized debt liability were $6.5 million and $6.8 million as of September 30, 2016 and December 31, 2015, respectively, and are included as a direct deduction to long-term debt.

We adopted Accounting Standards Update 2015-07 Fair Value Measurement (Topic 820) for the fiscal year beginning January 1, 2016. This update affects the presentation of investments for which fair value is measured at net asset value per share (or its equivalent) as a practical expedient. See Note 2 - Fair Value Measurements above.

# 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. These risks, uncertainties, and other factors include, but are not limited to, general business conditions, 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 September 30, 2016, there have been no significant changes in our critical accounting policies as disclosed in our 2015 Annual Report on Form 10-K. These policies include the accounting for regulated operations, deferred energy, margin stabilization, accounting for asset retirement and environmental obligations, and accounting for derivatives and hedging.

## Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of ODEC and TEC. See Note 1—Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

## Overview

We are a not-for-profit power supply cooperative owned entirely by our eleven Class A member distribution cooperatives and a Class B member, TEC. We supply our member distribution cooperatives' energy and demand requirements through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases. We also supply the transmission services necessary to deliver this power to our member distribution cooperatives.

Our results for the three and nine months ended September 30, 2016, were primarily impacted by changes in our member distribution cooperatives' requirements for power and our need for purchased power, and our continued investment in Wildcat Point.

- Our energy sales in MWh to our member distribution cooperatives for the three and nine months ended September 30, 2016, were relatively flat and 7.8% lower, respectively, as compared to the same periods in 2015. The milder weather we experienced during the first half of 2016 was partially offset by the warmer weather in the third quarter of 2016 as compared to the same periods in 2015. Additionally, we had decreases in our load requirements related to a limited exception provision in our wholesale power contract and retail choice in Virginia.

- Purchased power expense decreased $85.2 million, or 21.7%, for the nine months ended September 30, 2016, respectively, as compared to the same period in 2015, due to decreased volume of purchased energy as well as decreased average cost of purchased energy.

- During the nine months ended September 30, 2016, we capitalized $181.3 million of construction costs related to Wildcat Point. Through September 30, 2016, capitalized construction costs related to Wildcat Point totaled $670.0 million.

**Wildcat Point Generation Facility**

We are currently constructing, and will be the sole owner of, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to governmental and regulatory approvals. On April 8, 2014, we received a Final Order granting approval of the CPCN from the MPSC. On June 2, 2014, we selected White Oak Power Constructors as the EPC contractor and permanent construction began in January 2015. We currently anticipate that the project cost will be approximately $834.3 million, including capitalized interest. On September 14, 2016, a transformer at Wildcat Point caught fire. The fire was contained and extinguished, and did not present an environmental hazard. There was no other damage to the facility and no loss is expected to be recorded. The facility is still scheduled to become operational in mid-2017.

Wildcat Point's major equipment will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. In June 2014, following the approval of the CPCN and our selection of the EPC contractor, we began capitalizing all construction-related costs related to Wildcat Point. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through September 30, 2016, we capitalized construction costs related to Wildcat Point totaling $670.0 million, including $34.3 million of capitalized interest.

**Limited Exception under Wholesale Power Contracts**

We have a wholesale power contract with each of our member distribution cooperatives. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions. One of the limited exceptions permits the member distribution cooperative to receive up to the greater of 5% of its power requirements or 5 MW from owned generation or other suppliers. As of March 31, 2016, our member distribution cooperatives collectively received approximately 9 MW under this exception. Beginning May 1, 2016, our member distribution cooperatives collectively receive approximately 60 MW under this exception. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows. For further discussion on Wholesale Power Contracts, see "Business—Members—Member Distribution Cooperatives—Wholesale Power Contracts" in Item 1 of our 2015 Annual Report on Form 10-K.

**Retail Choice in Virginia**

In Virginia, retail choice in the selection of a power supplier is available to customers that consume at least 5 MW of power individually or in the aggregate (with aggregation subject to the approval of the VSCC) and that do not account for more than 1% of the incumbent utility's peak load during the past year. Currently, no customer of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Beginning June 1, 2016, Bear Island, an industrial customer of REC and the only customer of any of our member distribution cooperatives that has noncoincident peak demand that exceeds 90 MW, elected to purchase its power requirements from an alternate supplier. During 2015, Bear Island represented approximately 3.3% of our revenues from our member distribution cooperatives. We do not anticipate that this will have a material impact on our financial condition, results of operations, or cash flows. For further discussion on Retail Choice in Virginia, see "Business—Members—Member Distribution Cooperatives—Competition" in Item 1 of our 2015 Annual Report on Form 10-K.

**Factors Affecting Results**

**Formula Rate**

Our power sales are comprised of two power products – energy and 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 demand.

The rates we charge our member distribution cooperatives for sales of energy and demand are determined by a formula rate accepted by 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 formula 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.

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 rates, the base energy rate and the energy adjustment rate. Effective January 1, 2014, pursuant to FERC's acceptance of revisions to the formula rate as issued in FERC's December 2, 2013 order, the base energy rate is developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the energy adjustment rate will be zero. With board approval, we can revise the energy adjustment rate at any time during the year if it becomes apparent that the combined base energy rate and the current energy adjustment rate are over-collecting or under-collecting our actual and anticipated energy costs. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part II, Item 1.

Demand costs, which are primarily fixed costs, such as depreciation expense, interest expense, administrative and general expenses, capacity costs under power purchase contracts with third parties, transmission costs, and our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. The formula rate allows us to change the actual demand rates we charge as our demand-related costs change, without FERC approval, with the exception of decommissioning cost, which is a fixed number in the formula rate that requires FERC approval prior to any adjustment. FERC approval is also needed to change account classifications currently in the formula or to add accounts not otherwise included in the current formula. Additionally, depreciation studies are required to be filed with FERC for its approval if they would result in a change in our depreciation rates. Effective January 1, 2014, pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order, we collect our total demand costs through the following three separate rates:

- transmission service rate – designed to collect transmission-related and distribution-related costs;
- RTO capacity service rate – a proxy rate based on capacity prices in PJM which PJM allocates to ODEC and all other PJM members; and
- remaining owned capacity service rate – recovers all remaining demand costs not billed and/or recovered under the transmission service and RTO capacity service rates.

As stated above, our margin requirements and additional equity contributions approved by our board of directors are recovered through our demand rates. We establish our demand rates to produce a net margin attributable to ODEC equal to 20% of our budgeted total interest charges plus additional equity contributions approved by our board of directors. Effective January 1, 2014:

- At year end, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 20% of our actual total interest charges, our board of directors may approve that, utilizing Margin Stabilization, revenues will be reduced by the amount of such excess margins, or that such excess margins will be retained as an additional equity contribution. For year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 20% of our actual total interest charges, utilizing Margin Stabilization, revenues will be reduced by the amount of such excess margins.
- At year end and for year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals more than 10% but less than 20% of our actual total interest charges, no adjustment is recorded.
- At year end and for year-to-date interim reporting, if the actual net margin attributable to ODEC, excluding any budgeted additional equity contributions, equals less than 10% of our actual total interest charges, utilizing Margin Stabilization, revenues will be increased to produce a net margin attributable to ODEC, excluding any budgeted additional equity contributions, equal to 10% of our actual total interest charges.

For the three and nine months ended September 30, 2016, we recorded a reduction in operating revenues of $11.5 million and $13.7 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges. For the three and nine months ended September 30, 2015, we recorded a reduction in operating revenues of $3.0 million and $9.8 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.

**Weather**

Weather affects the demand for electricity. Relatively higher or lower temperatures tend to increase the demand for energy to use air conditioning and heating systems, respectively. Mild weather generally reduces the demand because heating and air conditioning systems are operated less. Weather also plays a role in the price of market energy through its effects on the market price for fuel, particularly natural gas. Heating and cooling degree days are measurement tools used to quantify the need to utilize heating or cooling, respectively, for a building. The heating and cooling degree days for the three and nine months ended September 30, 2016 and 2015, were as follows:

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Change | 2016 | 2015 | Change |
| Heating degree days | — | — | — | 2,087 | 2,708 | (22.9)% |
| Cooling degree days | 1,255 | 916 | 37.0% | 1,519 | 1,369 | 11.0% |

**Power Supply Resources**

We provide power to our members through a combination of our interests in Clover, a coal-fired generating facility; North Anna, a nuclear power station; our three combustion turbine facilities – Louisa, Marsh Run, and Rock Springs; distributed generation facilities; and physically-delivered forward power purchase contracts and spot market energy purchases. Our energy supply resources for the three and nine months ended September 30, 2016 and 2015, were as follows:

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2016 | | 2015 | | 2016 | | 2015 | |
| | (in MWh and percentages) | | | | (in MWh and percentages) | | | |
| **Generated:** | | | | | | | | |
| Clover | 794,095 | 23.2% | 787,914 | 22.3% | 2,154,822 | 22.0% | 2,001,019 | 18.4% |
| North Anna | 418,197 | 12.2 | 487,545 | 13.8 | 1,313,814 | 13.4 | 1,387,335 | 12.8 |
| Louisa | 157,798 | 4.6 | 139,207 | 4.0 | 310,577 | 3.2 | 293,242 | 2.7 |
| Marsh Run | 307,072 | 9.0 | 276,357 | 7.8 | 438,925 | 4.5 | 603,772 | 5.6 |
| Rock Springs | 310,100 | 9.0 | 187,952 | 5.3 | 347,670 | 3.5 | 295,958 | 2.7 |
| Distributed Generation | 960 | — | 752 | — | 1,063 | — | 1,306 | — |
| Total Generated | 1,988,222 | 58.0 | 1,879,727 | 53.2 | 4,566,871 | 46.6 | 4,582,632 | 42.2 |
| **Purchased:** | | | | | | | | |
| Other than renewable: | | | | | | | | |
| Long-term and short-term | 1,008,487 | 29.4 | 1,380,504 | 39.0 | 4,008,255 | 40.9 | 5,218,070 | 48.1 |
| Spot market | 312,505 | 9.1 | 173,070 | 4.9 | 696,951 | 7.1 | 534,096 | 4.9 |
| Total Other than renewable | 1,320,992 | 38.5 | 1,553,574 | 43.9 | 4,705,206 | 48.0 | 5,752,166 | 53.0 |
| Renewable (1) | 120,356 | 3.5 | 101,649 | 2.9 | 530,260 | 5.4 | 519,340 | 4.8 |
| Total Purchased | 1,441,348 | 42.0 | 1,655,223 | 46.8 | 5,235,466 | 53.4 | 6,271,506 | 57.8 |
| Total Available Energy | 3,429,570 | 100.0% | 3,534,950 | 100.0% | 9,802,337 | 100.0% | 10,854,138 | 100.0% |

(1) Related to our contracts from renewable facilities from which we purchase renewable energy credits. We sell these renewable energy credits to our member distribution cooperatives and non-members.

**Generating Facilities**

Our operating expenses, and consequently our rates to our member distribution cooperatives, are significantly affected by the operations of our baseload generating facilities, Clover and North Anna. Baseload generating facilities, particularly nuclear power plants such as North Anna, generally have relatively high fixed costs. Nuclear facilities operate with relatively low variable costs due to lower fuel costs and technological efficiencies. In addition, coal-fired facilities have relatively low variable costs, as compared to combustion turbine facilities such as Louisa, Marsh Run, and Rock Springs. Our combustion turbine facilities have relatively low fixed costs and greater operational flexibility; however, they may be more expensive to operate and, as a result, are dispatched only when the market price of energy makes their operation economical or when their operation is required by PJM to meet system reliability requirements. Recent prices of natural gas have made the operation of our combustion turbine facilities economical, resulting in increased dispatch.

Our generating facilities are under dispatch control of PJM. For further discussion on PJM, see "Business—Power Supply Resources—PJM" in Item 1 of our 2015 Annual Report on Form 10-K. Typically, nuclear facilities are almost always dispatched and coal-fired and combustion turbine facilities are generally dispatched based upon economic factors including the market price of energy, and to meet system reliability requirements.

The operational availability of our owned generating resources for the three and nine months ended September 30, 2016 and 2015, was as follows:

| | **Three Months Ended September 30,** | | **Nine Months Ended September 30,** | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Clover | 98.0% | 95.6% | 88.9% | 82.1% |
| North Anna | 86.8 | 100.0 | 89.1 | 95.3 |
| Louisa | 99.6 | 98.3 | 98.9 | 97.5 |
| Marsh Run | 100.0 | 99.7 | 97.7 | 97.3 |
| Rock Springs | 93.7 | 77.3 | 93.3 | 91.5 |

The output of Clover and North Anna for the three and nine months ended September 30, 2016 and 2015, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

| | **Three Months Ended September 30,** | | **Nine Months Ended September 30,** | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Clover | 83.0% | 82.3% | 75.8% | 70.7% |
| North Anna | 86.3 | 100.6 | 90.2 | 96.5 |

The scheduled and unscheduled outages for Clover and North Anna for the three and nine months ended September 30, 2016 and 2015, were as follows:

| | **Clover** | | | | **North Anna** | | | |
|---|---|---|---|---|---|---|---|---|
| | **Three Months Ended September 30,** | | **Nine Months Ended September 30,** | | **Three Months Ended September 30,** | | **Nine Months Ended September 30,** | |
| | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** |
| | (in days) | | (in days) | | (in days) | | (in days) | |
| Scheduled | — | 5.0 | 35.1 | 85.3 | 20.0 | — | 55.3 | 20.5 |
| Unscheduled | 3.6 | 3.1 | 25.5 | 12.4 | 4.3 | — | 4.3 | 5.3 |
| Total | 3.6 | 8.1 | 60.6 | 97.7 | 24.3 | — | 59.6 | 25.8 |

Each unit at North Anna is scheduled for refueling approximately every 18 months. While only one unit is refueled at a time, this typically results in both units being off-line for refueling during the same calendar year once every three years. During 2016, both units at North Anna have scheduled refueling outages.

**Sales to Member Distribution Cooperatives**

Revenues from sales to our member distribution cooperatives are a function of our formula rate for sales of power and sales of renewable energy credits to our member distribution cooperatives, and our member distribution cooperatives' customers' requirements for power. Our formula rate is based on our cost of service in meeting these requirements. See "Factors Affecting Results—Formula Rate" above.

**Sales to TEC**

In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which ODEC is the primary beneficiary. The financial statements of TEC are consolidated and the intercompany balances are eliminated in consolidation. TEC's sales to third parties are reflected as revenues from sales to non-members; however, in 2016 and 2015, TEC had no sales to third parties.

**Sales to Non-members**

Sales to non-members consist of sales of excess purchased and generated energy and sales of renewable energy credits. We primarily sell excess energy to PJM at the prevailing market price at the time of sale. Excess energy is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, and changes in market conditions. Renewable energy credits that are not sold to our member distribution cooperatives are sold to non-members.

## Results of Operations

### Operating Revenues

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives and non-members. Our operating revenues by type of purchaser for the three and nine months ended September 30, 2016 and 2015, were as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| | (in thousands) | | (in thousands) | |
| Revenues from sales to: | | | | |
| Member distribution cooperatives | | | | |
| Energy revenues [1] | $ 133,201 | $ 153,850 | $ 390,910 | $ 479,680 |
| Demand revenues | 81,764 | 89,773 | 262,963 | 275,233 |
| Total revenues from sales to member distribution cooperatives | 214,965 | 243,623 | 653,873 | 754,913 |
| Non-members [2] | 7,837 | 10,642 | 24,537 | 40,949 |
| Total operating revenues | $ 222,802 | $ 254,265 | $ 678,410 | $ 795,862 |
| | | | | |
| Average cost of energy to member distribution cooperatives (per MWh) | $ 40.93 | $ 47.19 | $ 42.51 | $ 48.11 |
| Average cost of demand to member distribution cooperatives (per MWh) | 25.13 | 27.54 | 28.60 | 27.61 |
| Average total cost to member distribution cooperatives (per MWh) | $ 66.06 | $ 74.73 | $ 71.11 | $ 75.72 |

(1) Includes sales of renewable energy credits of $0.9 million and $2.5 million for the three and nine months ended September 30, 2016, respectively, and $0.8 million and $2.2 million for the three and nine months ended September 30, 2015, respectively.

(2) Includes sales of renewable energy credits of $1.7 million and $8.4 million for the three and nine months ended September 30, 2016, respectively, and $1.0 million and $8.5 million for the three and nine months ended September 30, 2015, respectively.

Our energy sales in MWh to our member distribution cooperatives and non-members for the three and nine months ended September 30, 2016 and 2015, were as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| | (in MWh) | | (in MWh) | |
| Energy sales to: | | | | |
| Member distribution cooperatives | 3,254,047 | 3,259,985 | 9,194,937 | 9,969,176 |
| Non-members | 147,590 | 263,586 | 526,815 | 838,142 |
| Total energy sales | 3,401,637 | 3,523,571 | 9,721,752 | 10,807,318 |

Our energy sales in MWh to our member distribution cooperatives for the three and nine months ended September 30, 2016, were relatively flat and 7.8% lower, respectively, as compared to the same periods in 2015. The milder weather we experienced during the first half of 2016 was partially offset by the warmer weather in the third quarter of 2016 as compared to the same periods in 2015. Additionally, we had decreases in our load requirements of 268,024 MWh and 389,775 MWh for the three and nine months ended September 30, 2016, respectively, as compared to the same periods in 2015, related to a limited exception provision in our wholesale power contract and retail choice in Virginia. Effective May 1, 2016, one of our member distribution cooperatives elected to purchase 51 MW from an alternate supplier in accordance with a limited exception provision in our wholesale power contract. Effective June 1, 2016, Bear Island, an industrial customer of REC, elected to purchase its power requirements from an alternate supplier in accordance with retail choice in Virginia, thus reducing REC's requirements for power.

Our energy sales in MWh to non-members for the three and nine months ended September 30, 2016, were 44.0% and 37.1% lower, respectively, as compared to the same periods in 2015 as the result of the decrease in the volume of excess purchased and generated energy.

Total revenues from sales to our member distribution cooperatives for the three months ended September 30, 2016, decreased $28.7 million, or 11.8%, as compared to the same period in 2015, substantially due to the $20.6 million, or 13.4%, decrease in energy revenues. The decrease in energy revenues is due to the 13.3% decrease in the average cost of energy to member distribution cooperatives. Total revenues from sales to our member distribution cooperatives for the nine months ended September 30, 2016, decreased $101.0 million, or 13.4%, as compared to the same period in 2015, substantially due to the $88.8 million, or 18.5%, decrease in energy revenues. The decrease in energy revenues is due to the 11.6% decrease in the average cost of energy to member distribution cooperatives and the 7.8% decrease in energy sales volume.

The average total cost to member distribution cooperatives is affected by changes in our revenues as well as energy sales volumes. Our average total cost to member distribution cooperatives per MWh for the three and nine months ended September 30, 2016, was 11.6% and 6.1% lower as compared to the same periods in 2015, substantially as a result of the decrease in our total energy rate.

The following table summarizes the changes to our total energy rate which were implemented to address the differences in our realized as well as projected energy costs:

| Effective Date of Rate Change | % Change |
|---|---|
| January 1, 2015 | (0.3) |
| July 1, 2015 | (2.9) |
| January 1, 2016 | (5.4) |
| April 1, 2016 | (6.8) |
| September 1, 2016 | (6.5) |

Revenues from sales to non-members for the three months ended September 30, 2016, decreased $2.8 million, or 26.4%, as compared to the same period in 2015, due to an $3.4 million decrease in revenue from sales of excess energy slightly offset by a $0.6 million increase in revenue from sales of renewable energy credits. The decrease in revenue from sales of excess energy was due to a 44.0% decrease in the volume of excess energy sales partially offset by a 15.0% increase in the average price of excess energy. Revenues from sales to non-members for the nine months ended September 30, 2016, decreased $16.4 million, or 40.1%, as compared to the same period in 2015, primarily due to a $15.9 million decrease in revenue from sales of excess energy. The decrease in revenue from sales of excess energy was due to a 37.1% decrease in the volume of excess energy sales and a 19.9% decrease in the average price of excess energy. We primarily sell excess energy to PJM at the prevailing market price at the time of sale. Excess energy is the result of changes in our purchased power portfolio, differences between actual and forecasted needs, and changes in market conditions.

**Operating Expenses**

The following is a summary of the components of our operating expenses for three and nine months ended September 30, 2016 and 2015:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| | (in thousands) | | (in thousands) | |
| Fuel | $ 47,337 | $ 48,717 | $ 111,925 | $ 127,945 |
| Purchased power | 86,320 | 95,339 | 306,601 | 391,772 |
| Transmission | 30,008 | 29,456 | 92,368 | 84,614 |
| Deferred energy | 10,562 | 31,481 | 20,976 | 33,175 |
| Operations and maintenance | 13,100 | 10,750 | 38,277 | 39,584 |
| Administrative and general | 10,843 | 9,702 | 31,638 | 30,193 |
| Depreciation and amortization | 11,686 | 11,456 | 34,854 | 33,657 |
| Amortization of regulatory asset/(liability), net | 608 | 835 | 685 | 2,421 |
| Accretion of asset retirement obligations | 1,212 | 1,161 | 3,633 | 3,533 |
| Taxes, other than income taxes | 2,104 | 2,071 | 6,323 | 6,263 |
| Total Operating Expenses | $ 213,780 | $ 240,968 | $ 647,280 | $ 753,157 |

Our operating expenses are comprised of the costs that we incur to generate and purchase power to meet the needs of our member distribution cooperatives, and the costs associated with any sales of power to non-members. Our energy costs generally are variable and include the energy portion of our purchased power expense, fuel expense, and the variable portion of operations and maintenance expense. Our demand costs generally are fixed and include transmission expense, the capacity portion of our purchased power expense, the fixed portion of operations and maintenance expense, administrative and general expense, and depreciation and amortization expense. Additionally, all non-operating expenses and income items, including interest charges, net and investment income, are components of our demand costs. See "Factors Affecting Results—Formula Rate" above.

Total operating expenses decreased $27.2 million, or 11.3%, and $105.9 million, or 14.1%, for the three and nine months ended September 30, 2016, respectively, as compared to the same periods in 2015. The decrease for the three months ended September 30, 2016, was primarily due to decreases in deferred energy expense and purchased power expense. The decrease for the nine months ended September 30, 2016, was primarily due to decreases in purchased power expense, fuel expense, and deferred energy expense, partially offset by the increase in transmission expense.

- Purchased power expense, which includes the cost of purchased energy and capacity, decreased $9.0 million, or 9.5%, for the three months ended September 30, 2016, as compared to the same period in 2015. The volume of purchased energy decreased 12.9% and the average cost of purchased energy increased 12.7% for the three months ended September 30, 2016, as compared to the same period in 2015. In September 2016, we recorded a $6.5 million reduction to purchased power expense related to a billing dispute settlement with FirstEnergy Service Company. Purchased power expense decreased $85.2 million, or 21.7%, for the nine months ended September 30, 2016, as compared to the same period in 2015. The volume of purchased energy decreased 16.5% and the average cost of purchased energy decreased 6.1%.

- Fuel expense decreased $16.0 million, or 12.5%, for the nine months ended September 30, 2016, as compared to the same period in 2015. This decrease was primarily driven by the 23.3% decrease in the average cost of fuel for our combustion turbine facilities and the 8.0% decrease in the dispatch of our combustion turbine facilities.

- Deferred energy expense decreased $20.9 million for the three months ended September 30, 2016, as compared to the same period in 2015. For the three months ended September 30, 2016 and 2015, we over-collected $10.6 million and $31.5 million, respectively. Deferred energy expense decreased $12.2 million for the nine months ended September 30, 2016, as compared to the same period in 2015. For the nine months ended September 30, 2016 and 2015, we over-collected $21.0 million and $33.2 million, respectively. Deferred energy expense represents the difference between energy revenues and energy expenses. For further discussion on deferred energy, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Deferred Energy" in Item 7 of our 2015 Annual Report on Form 10-K.

- Transmission expense increased $7.8 million, or 9.2%, for the nine months ended September 30, 2016, as compared to the same period in 2015, primarily due to increases in PJM charges for network transmission services.

**Other Items**

**Investment Income**

Investment income increased $0.2 million, or 11.0%, and decreased $1.3 million, or 29.4%, for the three and nine months ended September 30, 2016, respectively, as compared to the same periods in 2015. In September 2016, we recorded $0.5 million of interest income related to a billing dispute settlement with FirstEnergy Service Company. This increase was partially offset by decreases in income earned on our nuclear decommissioning trust.

**Interest Charges, Net**

The primary factors affecting our interest charges, net are issuance of indebtedness, scheduled payments of principal on our indebtedness, interest charges related to our revolving credit facility, and capitalized interest. The major components of interest charges, net for the three and nine months ended September 30, 2016 and 2015, were as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2016 | 2015 | 2016 | 2015 |
| | (in thousands) | | (in thousands) | |
| Interest on long-term debt | $ (14,282) | $ (14,693) | $ (42,843) | $ (43,510) |
| Interest on revolving credit facility | (451) | (164) | (815) | (545) |
| Other interest | (223) | (171) | (836) | (405) |
| Total interest charges | (14,956) | (15,028) | (44,494) | (44,460) |
| Allowance for borrowed funds used during construction | 8,100 | 3,993 | 21,932 | 8,645 |
| Interest charges, net | $ (6,856) | $ (11,035) | $ (22,562) | $ (35,815) |

Interest charges, net decreased $4.2 million, or 37.9%, and $13.3 million, or 37.0%, for the three and nine months ended September 30, 2016, respectively, as compared to the same periods in 2015, primarily due to the increase in allowance for borrowed funds used during construction (capitalized interest) related to Wildcat Point.

**Net Margin Attributable to ODEC**

Net margin attributable to ODEC, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, was relatively flat for the three and nine months ended September 30, 2016, as compared to the same periods in 2015.

## Financial Condition

The principal changes in our financial condition from December 31, 2015 to September 30, 2016, were caused by the increases in construction work in progress, revolving credit facility, deferred energy, and accrued expenses, and decreases in deferred credits and other liabilities–other and accounts payable–members.

- Construction work in progress increased $163.4 million primarily due to expenditures related to Wildcat Point.
- Revolving credit facility increased $80.3 million due to outstanding borrowings under this facility.
- Deferred energy increased $21.0 million as a result of the over-collection of our energy costs in 2016. The deferred energy balance was a liability of $48.8 million and $27.8 million at September 30, 2016 and December 31, 2015, respectively.
- Accrued expenses increased $17.7 million primarily due to accrued interest on long-term debt.
- Deferred credits and other liabilities–other decreased $32.7 million primarily due to the reclassification of the $28.4 million retainage payable related to Wildcat Point which is now classified as a current liability.
- Accounts payable–members decreased $26.0 million primarily due to the decrease in member prepayments partially offset by the increase in amounts owed to our member distribution cooperatives under Margin Stabilization.

## Liquidity and Capital Resources

### Sources

Cash generated by our operations, periodic borrowings under our credit facility, and occasional issuances of long-term indebtedness provide our sources of liquidity and capital.

#### Operations

During the first nine months of 2016 and 2015, our operating activities provided cash flows of $81.1 million and $156.1 million, respectively. Operating activities in 2016 were primarily impacted by the following:

- Deferred energy changed $21.0 million due to the increase in the over-collection of our energy costs in 2016 as compared to 2015;
- Current liabilities changed $19.8 million due to changes in accounts payable–members, accounts payable, and accrued expenses;
- Current assets changed $9.7 million primarily due to the change in fuel, materials, and supplies; and
- Regulatory assets and liabilities changed $8.8 million due to changes in derivative activity.

#### Revolving Credit Facility

We maintain a $500.0 million revolving credit facility to cover our short-term and medium-term funding needs that are not met by cash from operations or other available funds. Commitments under this syndicated credit agreement extend until March 5, 2019. At September 30, 2016, we had $80.3 million outstanding under this facility. At December 31, 2015, we did not have any borrowings outstanding under this facility. At September 30, 2016 and December 31, 2015, we had letters of credit outstanding in the amount of $5.2 million and $8.2 million, respectively.

#### Financings

We fund the portion of our capital expenditures that we are not able to fund from operations through borrowings under our revolving credit facility and financings in the debt capital markets. These capital expenditures consist primarily of the costs related to the development, construction, acquisition, or improvement of our owned generating facilities.

### Uses

Our uses of liquidity and capital relate to funding our working capital needs, investment activities, and financing activities. Substantially all of our investment activities relate to capital expenditures in connection with our generating facilities. We expect that cash flow from our operations, borrowings under our revolving credit facility, and financings in the debt capital markets will be sufficient to meet our currently anticipated future operational and capital requirements.

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

No material changes occurred in our exposure to market risk during the third quarter of 2016.

## 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 material changes in our internal controls over financial reporting or in other factors that could significantly affect such controls during the past fiscal quarter.

## PART II. OTHER INFORMATION

## ITEM 1. LEGAL PROCEEDINGS

### FERC Proceeding Related to Formula Rate

On September 30, 2013, we filed with FERC to revise our cost-based formula rate in order to more closely align our cost recovery from our member distribution cooperatives with the methodologies used by PJM to allocate costs to us. On November 8, 2013, Bear Island, a customer of REC, filed a motion to intervene, protest, and request for hearing. On December 2, 2013, FERC issued its order accepting the proposed revisions for filing to become effective January 1, 2014, subject to refund, and establishing hearing and settlement procedures. We received an initial decision from the hearing judge on April 13, 2015. The hearing judge found many components of the formula rate to be just and reasonable. We believe all components of the formula rate are just and reasonable and addressed the components the hearing judge found to be unjust and unreasonable in our brief on exceptions. Briefs on exceptions to the initial decision and briefs opposing exceptions to the initial decision were filed in 2015. The FERC commissioners have the ultimate authority in this proceeding and they have no timetable to issue a final order. Our formula rate remains in effect subject to refund pending a final order from FERC. If a refund is ultimately determined, we believe it will result in a reallocation of costs among our member distribution cooperatives.

### 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 2015 Annual Report on Form 10-K, which could affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

## ITEM 5. OTHER INFORMATION

*Recovery of Costs from PJM*

On June 23, 2014, we filed a petition at FERC seeking recovery from PJM of approximately $14.9 million of unreimbursed costs, which were incurred during the first quarter of 2014 related to the dispatch of our combustion turbine generating facilities. On June 9, 2015, FERC denied our petition, on July 9, 2015, we filed a request for rehearing, and on August 10, 2015, FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. On March 1, 2016, FERC denied our request for rehearing and on April 11, 2016, we filed a Petition for Review in the U.S. Court of Appeals for the District of Columbia Circuit. We have not recorded a receivable related to this matter.

**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 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

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: November 10, 2016

/s/ Robert L. Kees

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

EXHIBIT INDEX

| Exhibit Number | Description of Exhibit |
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| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

**Exhibit 31.1**

**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 annual 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: November 10, 2016

/s/ JACKSON E. REASOR

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

**Exhibit 31.2**

**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 annual 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: November 10, 2016

/s/ ROBERT L. KEES

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

**Exhibit 32.1**

**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 September 30, 2016 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: November 10, 2016

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

**Exhibit 32.2**

**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 September 30, 2016 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: November 10, 2016

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