

**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, 2015

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

Non-accelerated
filer

Accelerated filer

Smaller reporting com
pany

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:

<u>Abbreviation or Acronym</u>	<u>Definition</u>
Alstom	Alstom Power, Inc.
Bear Island	Bear Island Paper WB LLC
CCR	Coal combustion residual
Clover	Clover Power Station
CO ₂	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction
FASB	Financial Accounting Standards Board
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
RPM	Reliability Pricing Model
RTO	Regional transmission organization
TEC	TEC Trading, Inc.
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, 2015	December 31, 2014
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	\$ 1,713,175	\$ 1,690,555
Less accumulated depreciation	(811,942)	(784,215)
Net Property, plant, and equipment	901,233	906,340
Nuclear fuel, at amortized cost	19,222	19,376
Construction work in progress	442,316	171,953
Net Electric Plant	1,362,771	1,097,669
Investments:		
Nuclear decommissioning trust	140,692	145,822
Lease deposits	101,080	99,191
Unrestricted investments and other	7,013	7,049
Total Investments	248,785	252,062
Current Assets:		
Cash and cash equivalents	174,312	1,424
Accounts receivable	6,345	8,656
Accounts receivable—members	77,713	83,108
Fuel, materials, and supplies	60,998	64,154
Deferred energy	—	19,948
Prepayments and other	37,892	5,131
Total Current Assets	357,260	182,421
Deferred Charges:		
Regulatory assets	84,380	87,987
Other	11,224	18,603
Total Deferred Charges	95,604	106,590
Total Assets	<u>\$ 2,064,420</u>	<u>\$ 1,638,742</u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 387,988	\$ 379,097
Non-controlling interest	5,694	5,687
Total Patronage capital and Non-controlling interest	393,682	384,784
Long-term debt	1,053,038	721,038
Revolving credit facility	—	86,000
Total Long-term debt and Revolving credit facility	1,053,038	807,038
Total Capitalization	1,446,720	1,191,822
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	142,896	96,702
Accounts payable—members	103,291	35,217
Accrued expenses	23,742	4,568
Deferred energy	13,227	—
Total Current Liabilities	311,448	164,779
Deferred Credits and Other Liabilities:		
Asset retirement obligations	117,038	104,936
Obligations under long-term lease	89,148	84,730
Regulatory liabilities	69,918	78,764
Other	30,148	13,711
Total Deferred Credits and Other Liabilities	306,252	282,141
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	<u>\$ 2,064,420</u>	<u>\$ 1,638,742</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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Operating Revenues	\$ 254,265	\$ 233,904	\$ 795,862	\$ 716,331
Operating Expenses:				
Fuel	48,717	33,667	127,945	178,294
Purchased power	95,339	118,605	391,772	391,951
Transmission	29,456	19,688	84,614	56,504
Deferred energy	31,481	12,704	33,175	(64,256)
Operations and maintenance	10,750	12,468	39,584	39,151
Administrative and general	9,702	9,000	30,193	31,453
Depreciation and amortization	11,456	10,476	33,657	31,480
Amortization of regulatory asset/(liability), net	835	1,282	2,421	4,080
Accretion of asset retirement obligations	1,161	1,019	3,533	3,057
Taxes, other than income taxes	2,071	1,980	6,263	6,287
Total Operating Expenses	<u>240,968</u>	<u>220,889</u>	<u>753,157</u>	<u>678,001</u>
Operating Margin	13,297	13,015	42,705	38,330
Other expense, net	(801)	(785)	(2,489)	(2,224)
Investment income	1,542	1,650	4,498	5,177
Interest charges, net	(11,035)	(11,537)	(35,815)	(34,305)
Income taxes	1	1	(1)	2
Net Margin including Non-controlling interest	<u>3,004</u>	<u>2,344</u>	<u>8,898</u>	<u>6,980</u>
Non-controlling interest	1	5	(7)	9
Net Margin attributable to ODEC	<u>3,005</u>	<u>2,349</u>	<u>8,891</u>	<u>6,989</u>
Patronage Capital - Beginning of Period	384,983	374,637	379,097	369,997
Patronage Capital - End of Period	<u>\$ 387,988</u>	<u>\$ 376,986</u>	<u>\$ 387,988</u>	<u>\$ 376,986</u>

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,	
	2015	2014
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	\$ 8,898	\$ 6,980
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	33,657	31,480
Other non-cash charges	13,881	13,512
Amortization of lease obligations	4,418	4,126
Interest on lease deposits	(2,174)	(2,121)
Change in current assets	(21,899)	(2,562)
Change in deferred energy	33,175	(64,256)
Change in current liabilities	75,756	42,992
Change in regulatory assets and liabilities	3,969	336
Change in deferred charges-other and deferred credits and other liabilities-other	6,425	(2,643)
Net Cash Provided by Operating Activities	<u>156,106</u>	<u>27,844</u>
Investing Activities:		
Purchases of held to maturity securities	(130,000)	(2,240)
Proceeds from sale of held to maturity securities	130,000	20,000
Increase in other investments	(3,769)	(4,409)
Electric plant additions	(223,695)	(91,921)
Net Cash Used for Investing Activities	<u>(227,464)</u>	<u>(78,570)</u>
Financing Activities:		
Issuance of long-term debt	332,000	—
Debt issuance costs	(1,754)	—
Draws on revolving credit facility	104,000	222,954
Repayments on revolving credit facility	(190,000)	(187,954)
Net Cash Provided by Financing Activities	<u>244,246</u>	<u>35,000</u>
Net Change in Cash and Cash Equivalents	<u>172,888</u>	<u>(15,726)</u>
Cash and Cash Equivalents - Beginning of Period	1,424	51,669
Cash and Cash Equivalents - End of Period	<u>\$ 174,312</u>	<u>\$ 35,943</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. 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, 2015, our consolidated results of operations for the three and nine months ended September 30, 2015 and 2014, and cash flows for the nine months ended September 30, 2015 and 2014. The consolidated results of operations for the three and nine months ended September 30, 2015, 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 2014 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, 2015 and December 31, 2014. 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.

Transmission expense has been presented as a separate line item in the prior year's condensed consolidated financial statements 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.

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The following table summarizes our financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2015 and December 31, 2014:

	September 30, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)			
Nuclear decommissioning trust ⁽¹⁾⁽²⁾	\$ 140,692	\$ 46,103	\$ 94,589	\$ —
Unrestricted investments and other ⁽³⁾	202	—	202	—
Total Financial Assets	\$ 140,894	\$ 46,103	\$ 94,791	\$ —
Derivatives - gas and power ⁽⁴⁾	\$ 2,490	\$ 2,490	\$ —	\$ —
Total Financial Liabilities	\$ 2,490	\$ 2,490	\$ —	\$ —

	December 31, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	(in thousands)			
Nuclear decommissioning trust ⁽¹⁾⁽²⁾	\$ 145,822	\$ 45,573	\$ 100,249	\$ —
Unrestricted investments and other ⁽³⁾	198	—	198	—
Total Financial Assets	\$ 146,020	\$ 45,573	\$ 100,447	\$ —
Derivatives - gas and power ⁽⁴⁾	\$ 5,215	\$ 5,215	\$ —	\$ —
Total Financial Liabilities	\$ 5,215	\$ 5,215	\$ —	\$ —

⁽¹⁾ For additional information about our nuclear decommissioning trust see Note 4 below.

⁽²⁾ Nuclear decommissioning trust includes investments that are available for sale and classified as Level 2. These Level 2 assets consist of an equity fund that attempts to replicate the return of the S&P 500, an equity fund that invests in small capitalization stocks, and an equity fund that invests in international stocks. The fair values of the investments in the nuclear decommissioning trust have been estimated using the net asset value per share.

⁽³⁾ Unrestricted investments and other includes investments that are related to equity securities.

⁽⁴⁾ Derivatives - gas and power represent natural gas futures contracts which are recorded on our Condensed Consolidated Balance Sheet in deferred credits and other liabilities-other, and which are indexed against NYMEX. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2014 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 2014 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.

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4. Investments

Investments were as follows at September 30, 2015 and December 31, 2014:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
(in thousands)						
September 30, 2015						
Nuclear decommissioning trust ⁽¹⁾						
Debt securities	Available for sale	\$ 42,565	\$ 3,250	\$ —	\$ 45,815	\$ 45,815
Equity securities	Available for sale	71,541	23,048	—	94,589	94,589
Cash and other	Available for sale	288	—	—	288	288
Total Nuclear Decommissioning Trust		<u>\$ 114,394</u>	<u>\$ 26,298</u>	<u>\$ —</u>	<u>\$ 140,692</u>	<u>\$ 140,692</u>
Lease Deposits ⁽²⁾						
Government obligations	Held to maturity	\$ 101,080	\$ 5,731	\$ —	\$ 106,811	\$ 101,080
Total Lease Deposits		<u>\$ 101,080</u>	<u>\$ 5,731</u>	<u>\$ —</u>	<u>\$ 106,811</u>	<u>\$ 101,080</u>
Unrestricted investments						
Government obligations	Held to maturity	\$ 2,004	\$ 7	\$ —	\$ 2,011	\$ 2,004
Debt securities	Held to maturity	2,636	2	—	2,638	2,636
Total Unrestricted Investments		<u>\$ 4,640</u>	<u>\$ 9</u>	<u>\$ —</u>	<u>\$ 4,649</u>	<u>\$ 4,640</u>
Other						
Equity securities	Trading	\$ 167	\$ 35	\$ —	\$ 202	\$ 202
Non-marketable equity investments	Equity	2,171	1,954	—	4,125	2,171
Total Other		<u>\$ 2,338</u>	<u>\$ 1,989</u>	<u>\$ —</u>	<u>\$ 4,327</u>	<u>\$ 2,373</u>
						<u>\$ 248,785</u>
December 31, 2014						
Nuclear decommissioning trust ⁽¹⁾						
Debt securities	Available for sale	\$ 41,654	\$ 3,516	\$ —	\$ 45,170	\$ 45,170
Equity securities	Available for sale	68,259	31,990	—	100,249	100,249
Cash and other	Available for sale	403	—	—	403	403
Total Nuclear Decommissioning Trust		<u>\$ 110,316</u>	<u>\$ 35,506</u>	<u>\$ —</u>	<u>\$ 145,822</u>	<u>\$ 145,822</u>
Lease Deposits ⁽²⁾						
Government obligations	Held to maturity	\$ 99,191	\$ 5,569	\$ —	\$ 104,760	\$ 99,191
Total Lease Deposits		<u>\$ 99,191</u>	<u>\$ 5,569</u>	<u>\$ —</u>	<u>\$ 104,760</u>	<u>\$ 99,191</u>
Unrestricted investments						
Government obligations	Held to maturity	\$ 2,005	\$ —	\$ —	\$ 2,005	\$ 2,005
Debt securities	Held to maturity	2,636	—	(18)	2,618	2,636
Total Unrestricted Investments		<u>\$ 4,641</u>	<u>\$ —</u>	<u>\$ (18)</u>	<u>\$ 4,623</u>	<u>\$ 4,641</u>
Other						
Equity securities	Trading	\$ 151	\$ 47	\$ —	\$ 198	\$ 198
Non-marketable equity investments	Equity	2,210	1,821	—	4,031	2,210
Total Other		<u>\$ 2,361</u>	<u>\$ 1,868</u>	<u>\$ —</u>	<u>\$ 4,229</u>	<u>\$ 2,408</u>
						<u>\$ 252,062</u>

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- (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 2014 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.
- (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 2014 Annual Report on Form 10-K.

Our investments by classification at September 30, 2015 and December 31, 2014, were as follows:

<u>Description</u>	<u>September 30, 2015</u>		<u>December 31, 2014</u>	
	<u>Cost</u>	<u>Carrying Value</u>	<u>Cost</u>	<u>Carrying Value</u>
	(in thousands)			
Available for sale	\$ 114,394	\$ 140,692	\$ 110,316	\$ 145,822
Held to maturity	105,720	105,720	103,832	103,832
Equity	2,171	2,171	2,210	2,210
Trading	167	202	151	198
	<u>\$ 222,452</u>	<u>\$ 248,785</u>	<u>\$ 216,509</u>	<u>\$ 252,062</u>

Contractual maturities of debt securities at September 30, 2015, 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 ⁽¹⁾	\$ —	\$ —	\$ 45,815	\$ —	\$ 45,815
Held to maturity	517	105,203	—	—	105,720
	<u>\$ 517</u>	<u>\$ 105,203</u>	<u>\$ 45,815</u>	<u>\$ —</u>	<u>\$ 151,535</u>

- (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 generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to obtainment of necessary 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. Site preparation and engineering activities are in process, and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We currently have a ground lease related to land and land rights associated with Wildcat Point that is being accounted for as an operating lease. On June 22, 2015, we reached an agreement to purchase this land and these land rights from Essential Power, LLC for \$40.0 million and a payment of \$35.5 million was made in the third quarter and is recorded in prepayments and other. We anticipate the transaction will close in the fourth quarter of 2015. Upon closing of the transaction, title will be transferred to us and we will make the remaining payment of \$4.5 million. Prior to entering into the agreement to purchase the land and land rights, thus terminating the ground lease, we made prepaid rent payments related to the ground lease. We established a regulatory asset for the unamortized portion of the prepaid rent that will be amortized through May 31, 2017. The balance of this regulatory asset as of September 30, 2015, was \$3.5 million. As a result of the agreement to purchase the land and land rights, we currently anticipate that the project cost will be approximately \$834.3 million, including financing costs. To fund a portion of the project cost, on January 15, 2015, we issued \$332.0 million of first mortgage bonds in a private placement transaction.

Wildcat Point will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. Beginning 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. Through December 31, 2014, we capitalized construction costs related to Wildcat Point totaling \$115.8 million, which are recorded in construction work in progress. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through September 30, 2015, we capitalized construction costs related to Wildcat Point totaling \$390.8 million, including \$7.6 million of capitalized interest.

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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. A hearing was held in December 2014, briefs were filed in January 2015, and 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 on May 13, 2015, and June 2, 2015, respectively. 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. The results of FERC's further consideration of the matter cannot currently be determined and we have not recorded a receivable related to this matter.

Revolving Credit Facility

We currently maintain a \$500.0 million revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019. At September 30, 2015, we did not have any borrowings under this facility, as compared to December 31, 2014, when we had \$86.0 million outstanding. At September 30, 2015, and December 31, 2014, we had letters of credit outstanding in the amount of \$8.2 million and \$10.0 million, respectively.

Long-term Debt

On January 15, 2015, we issued \$332.0 million of first mortgage bonds in a private placement transaction. The issuance consisted of \$260.0 million of 4.46% First Mortgage Bonds, 2015 Series A due December 1, 2044 and \$72.0 million of 4.56% First Mortgage Bonds, 2015 Series B due December 1, 2053.

Disposal of Coal Combustion Residual

In December 2014, the EPA issued the final rule regulating the disposal of CCRs, commonly known as coal ash. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act. The final rule was published in the Federal Register in April 2015 and, as a result, we established asset retirement obligations totaling \$8.6 million during the second quarter of 2015.

New Accounting Pronouncements

In April 2015, the FASB issued Accounting Standards Update 2015-03 Interest-Imputation of Interest (Subtopic 835-30). This update requires that debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. We currently present debt issuance costs as an asset in deferred charges-other on our Condensed Consolidated Balance Sheet. We plan to adopt this standard for the fiscal year beginning January 1, 2016.

In May 2015, the FASB issued Accounting Standards Update 2015-07 Fair Value Measurement (Topic 820). This update affects the presentation of investments for which fair value is measured at net asset value per share (or its equivalent). We are currently evaluating the impact of this pronouncement on the presentation of the fair value of our nuclear decommissioning trust. We plan to adopt this standard for the fiscal year beginning January 1, 2016.

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. 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, 2015, there have been no significant changes in our critical accounting policies as disclosed in our 2014 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, 2015, were primarily impacted by the continuing effects from the unusually cold weather in the first quarter of 2014, and the construction of Wildcat Point.

- The unusually cold weather experienced in the entire mid-Atlantic region during the first quarter of 2014 continued to impact our operating results through the third quarter of 2015, and year over year comparisons. Increased costs in the first quarter of 2014, particularly fuel expense for our combustion turbine facilities, resulted in the under-collection of our energy costs, and an under-collected deferred energy balance of \$56.2 million at March 31, 2014. To address the under-collection of costs, we increased our energy rates during 2014. At September 30, 2015, our deferred energy balance was an over-collection of \$13.2 million.
- We continue with the construction of Wildcat Point (see "Wildcat Point Generation Facility" below). Through September 30, 2015, we capitalized construction costs totaling \$390.8 million. To fund a portion of the Wildcat Point project cost, on January 15, 2015, we issued \$332.0 million of long-term debt, and used a portion of the proceeds to repay borrowings outstanding under our revolving credit facility.

Wildcat Point Generation Facility

We are currently constructing, and will be the sole owner of, an approximate 1,000 MW natural gas-fueled generation facility, named Wildcat Point, in Cecil County, Maryland. The development, construction, and operation of Wildcat Point are subject to obtaining of necessary 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. Site preparation and engineering activities are in process, and permanent construction began in January 2015. The facility is scheduled to become operational in mid-2017. We currently have a ground lease related to land and land rights associated with Wildcat Point that is being accounted for as an operating lease. On June 22, 2015, we reached an agreement to purchase this land and these land rights from Essential Power, LLC for \$40.0 million and a payment of \$35.5 million was made in the third quarter and is recorded in

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prepayments and other. We anticipate the transaction will close in the fourth quarter of 2015. Upon closing of the transaction, title will be transferred to us and we will make the remaining payment of \$4.5 million. Prior to entering into the agreement to purchase the land and land rights, thus terminating the ground lease, we made prepaid rent payments related to the ground lease. We established a regulatory asset for the unamortized portion of the prepaid rent that will be amortized through May 31, 2017. The balance of this regulatory asset as of September 30, 2015, was \$3.5 million. As a result of the agreement to purchase the land and land rights, we currently anticipate that the project cost will be approximately \$834.3 million, including financing costs. To fund a portion of the project cost, on January 15, 2015, we issued \$332.0 million of first mortgage bonds in a private placement transaction.

Wildcat Point will consist of two Mitsubishi combustion turbines, two Alstom heat recovery steam generators, and one Alstom steam turbine generator. Beginning 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. Through December 31, 2014, we capitalized construction costs related to Wildcat Point totaling \$115.8, which are recorded in construction work in progress. In January 2015, we began capitalizing interest with respect to the facility upon commencement of permanent construction. Through September 30, 2015, we capitalized construction costs related to Wildcat Point totaling \$390.8 million, including \$7.6 million of capitalized interest.

Wholesale Power Contracts

We have wholesale power contracts 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 cooperatives to receive up to the greater of 5.0% of their power requirements or 5 MW from owned generation or other suppliers, and to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. Currently, our member distribution cooperatives collectively receive approximately 9 MW under this exception. Beginning in the second quarter of 2016, we currently anticipate that our member distribution cooperatives will 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 2014 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 no longer a fixed rate that requires FERC approval prior to adjustment. The base energy rate now 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.

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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 now 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, 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. For the three and nine months ended September 30, 2014, we recorded a reduction in operating revenues of \$40.1 thousand and \$1.9 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, 2015 and 2014, were as follows:

	Three Months Ended September 30,		%	Nine Months Ended September 30,		%
	2015	2014		Change	2015	
Heating degree days	—	—	—	2,708	2,607	3.9
Cooling degree days	916	744	23.1	1,369	1,064	28.7

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, 2015 and 2014, were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2015		2014		2015		2014	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	787,914	22.3%	685,719	21.0%	2,001,019	18.4%	1,996,626	19.8%
North Anna	487,545	13.8	423,734	13.0	1,387,335	12.8	1,399,014	13.8
Louisa	139,207	4.0	34,504	1.1	293,242	2.7	181,041	1.8
Marsh Run	276,357	7.8	93,499	2.8	603,772	5.6	342,820	3.4
Rock Springs	187,952	5.3	23,399	0.7	295,958	2.7	73,521	0.7
Distributed Generation	752	—	176	—	1,306	—	2,168	—
Total Generated	<u>1,879,727</u>	<u>53.2</u>	<u>1,261,031</u>	<u>38.6</u>	<u>4,582,632</u>	<u>42.2</u>	<u>3,995,190</u>	<u>39.5</u>
Purchased:								
Other than renewable:								
Long-term and short-term	1,380,504	39.0	1,620,616	49.6	5,218,070	48.1	4,710,558	46.6
Spot market	173,070	4.9	259,684	7.9	534,096	4.9	872,854	8.6
Total Other than renewable	<u>1,553,574</u>	<u>43.9</u>	<u>1,880,300</u>	<u>57.5</u>	<u>5,752,166</u>	<u>53.0</u>	<u>5,583,412</u>	<u>55.2</u>
Renewable ⁽¹⁾	101,649	2.9	127,748	3.9	519,340	4.8	538,059	5.3
Total Purchased	<u>1,655,223</u>	<u>46.8</u>	<u>2,008,048</u>	<u>61.4</u>	<u>6,271,506</u>	<u>57.8</u>	<u>6,121,471</u>	<u>60.5</u>
Total Available Energy	<u>3,534,950</u>	<u>100.0%</u>	<u>3,269,079</u>	<u>100.0%</u>	<u>10,854,138</u>	<u>100.0%</u>	<u>10,116,661</u>	<u>100.0%</u>

⁽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 are 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.

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 2014 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.

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The operational availability of our owned generating resources for the three and nine months ended September 30, 2015 and 2014, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Clover	95.6%	92.6%	82.1%	83.8%
North Anna	100.0	87.0	95.3	95.4
Louisa	98.3	100.0	97.5	97.5
Marsh Run	99.7	100.0	97.3	98.8
Rock Springs	77.3	99.4	91.5	97.6

The output of Clover and North Anna for the three and nine months ended September 30, 2015 and 2014, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Clover	82.3%	72.0%	70.7%	70.5%
North Anna	100.6	87.4	96.5	97.4

The scheduled and unscheduled outages for Clover and North Anna for the three and nine months ended September 30, 2015 and 2014, 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,	
	2015	2014	2015	2014	2015	2014	2015	2014
	(in days)				(in days)			
Scheduled	5.0	6.5	85.3	72.1	—	24.0	20.5	24.0
Unscheduled	3.1	7.2	12.4	16.5	—	—	5.3	1.3
Total	<u>8.1</u>	<u>13.7</u>	<u>97.7</u>	<u>88.6</u>	<u>—</u>	<u>24.0</u>	<u>25.8</u>	<u>25.3</u>

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 non-member revenues; however, in 2015 and 2014, 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, 2015 and 2014, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Revenues from sales to:				
Member distribution cooperatives				
Energy revenues ⁽¹⁾	\$ 153,850	\$ 147,770	\$ 479,680	\$ 436,414
Demand revenues	89,773	80,837	275,233	243,284
Total revenues from sales to member distribution cooperatives	243,623	228,607	754,913	679,698
Non-members ⁽²⁾	10,642	5,297	40,949	36,633
Total operating revenues	<u>\$ 254,265</u>	<u>\$ 233,904</u>	<u>\$ 795,862</u>	<u>\$ 716,331</u>
Average cost of energy to member distribution cooperatives (per MWh)	\$ 47.19	\$ 47.61	\$ 48.11	\$ 45.43
Average cost of demand to member distribution cooperatives (per MWh)	27.54	26.04	27.61	25.32
Average total cost to member distribution cooperatives (per MWh)	<u>\$ 74.73</u>	<u>\$ 73.65</u>	<u>\$ 75.72</u>	<u>\$ 70.75</u>

⁽¹⁾ Includes sales of renewable energy credits of \$0.8 million and \$2.2 million, for the three and nine months ended September 30, 2015, respectively, and \$0.8 million and \$1.3 million for the three and nine months ended September 30, 2014, respectively.

⁽²⁾ Includes sales of renewable energy credits of \$1.0 million and \$8.5 million for the three and nine months ended September 30, 2015, respectively, and \$0 million and \$3.7 million for the three and nine months ended September 30, 2014, respectively.

Our energy sales in MWh to our member distribution cooperatives and non-members for the three and nine months ended September 30, 2015 and 2014, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	3,259,985	3,103,902	9,969,176	9,607,339
Non-members	263,586	153,614	838,142	449,010
Total energy sales	<u>3,523,571</u>	<u>3,257,516</u>	<u>10,807,318</u>	<u>10,056,349</u>

Our energy sales in MWh to our member distribution cooperatives for the three and nine months ended September 30, 2015, were 5.0% and 3.8% higher, respectively, as compared to the same periods in 2014.

Our energy sales in MWh to non-members for the three and nine months ended September 30, 2015, were 71.6% and 86.7% higher, respectively, as compared to the same periods in 2014 as the result of the increase 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, 2015, increased \$15.0 million, or 6.6%, as compared to the same period in 2014, substantially due to the \$8.9 million, or 11.1%, increase in demand revenues, primarily due to increased transmission expenses. Additionally, energy revenues increased \$6.1 million, or 4.1%, due to the 5.0% increase in the volume of MWh sales to our member distribution cooperatives. Total revenues from sales to our member distribution cooperatives for the nine months ended September 30, 2015, increased \$75.2 million, or 11.1%, as compared to the same period in 2014, substantially due to the \$43.3 million, or 9.9%, increase in energy revenues. The increase in energy revenues is due to the 5.9% increase in the average cost of energy sold to our member distribution cooperatives and the 3.8% increase in the volume of MWh sales. Additionally, demand revenues increased \$31.9 million, or 13.1%, primarily due to increased transmission expenses.

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The average total cost to member distribution cooperatives is affected by changes in our revenues as well as sales volumes. Our average total cost to member distribution cooperatives per MWh for the three months ended September 30, 2015, was 1.5% higher, as compared to the same period in 2014, substantially as a result of an increase in demand costs primarily related to transmission expense. Our average total cost to member distribution cooperatives per MWh for the nine months ended September 30, 2015, was 7.0% higher, as compared to the same period in 2014, substantially as a result of the net increase in our total energy rate and an increase in demand costs primarily related to transmission expense.

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
April 1, 2014	11.8
October 1, 2014	2.4
January 1, 2015	(0.3)
July 1, 2015	(2.9)

Non-member revenue for the three months ended September 30, 2015, increased \$5.3 million, or 100.9%, as compared to the same period in 2014, primarily due to a 81.8% increase in revenue from sales of excess energy. The increase in revenue from sales of excess energy was due to a 71.6% increase in the volume of excess energy sales and a 5.9% increase in the average price of excess energy. Non-member revenue for the nine months ended September 30, 2015, increased \$4.3 million, or 11.8%, as compared to the same period in 2014, due to the 130.0% increase in revenue from 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.

Operating Expenses

The following is a summary of the components of our operating expenses for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Fuel	\$ 48,717	\$ 33,667	\$ 127,945	\$ 178,294
Purchased power	95,339	118,605	391,772	391,951
Transmission	29,456	19,688	84,614	56,504
Deferred energy	31,481	12,704	33,175	(64,256)
Operations and maintenance	10,750	12,468	39,584	39,151
Administrative and general	9,702	9,000	30,193	31,453
Depreciation and amortization	11,456	10,476	33,657	31,480
Amortization of regulatory asset/(liability), net	835	1,282	2,421	4,080
Accretion of asset retirement obligations	1,161	1,019	3,533	3,057
Taxes, other than income taxes	2,071	1,980	6,263	6,287
Total Operating Expenses	<u>\$ 240,968</u>	<u>\$ 220,889</u>	<u>\$ 753,157</u>	<u>\$ 678,001</u>

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 increased \$20.1 million, or 9.1%, and \$75.2 million, or 11.1%, for the three and nine months ended September 30, 2015, respectively, as compared to the same periods in 2014. The increase for the three months ended September 30, 2015, was primarily due to increases in deferred energy expense, fuel expense, and transmission expense, partially offset by the decrease in purchased power expense. The increase for the nine months ended September 30, 2015, was primarily due to increases in deferred energy expense and transmission expense, partially offset by the decrease in fuel expense.

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- Deferred energy expense increased \$18.8 million and \$97.4 million for the three and nine months ended September 30, 2015, respectively, as compared to the same periods in 2014. For the three months ended September 30, 2015 and 2014, we over-collected \$31.5 million and \$12.7 million, respectively. For nine months ended September 30, 2015, we over-collected \$33.2 million whereas for the nine months ended September 30, 2014, we under-collected \$64.3 million. 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 2014 Annual Report on Form 10-K.
- Transmission expense increased \$9.8 million, or 49.6%, and \$28.1 million, or 49.7%, for the three and nine months ended September 30, 2015, respectively, as compared to the same periods in 2014, primarily due to an increase in PJM charges for network transmission services.
- Fuel expense increased \$15.1 million, or 44.7%, for the three months ended September 30, 2015, as compared to the same period in 2014, primarily due to the 298.6% increase in the dispatch of our combustion turbine facilities partially offset by the 34.3% decrease in the average cost of fuel for our combustion turbine facilities. Fuel expense decreased \$50.3 million, or 28.2%, for the nine months ended September 30, 2015, as compared to the same period in 2014. This decrease was primarily driven by the 74.5% decrease in the average cost of fuel for our combustion turbine facilities partially offset by the 99.7% increase in the dispatch of our combustion turbine facilities.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased \$23.3 million, or 19.6%, for the three months ended September 30, 2015, as compared to the same period in 2014. The volume of purchased energy decreased 17.6% and the average cost of purchased energy decreased 5.1% for the three months ended September 30, 2015, as compared to the same period in 2014.

Other Items

Investment Income

Investment income decreased \$0.1 million, or 6.5%, and \$0.7 million, or 13.1%, for the three and nine months ended September 30, 2015, respectively, as compared to the same periods in 2014, primarily due to lower 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, 2015 and 2014, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Interest on long-term debt	\$ (14,693)	\$ (11,385)	\$ (43,510)	\$ (34,140)
Interest on revolving credit facility	(164)	(263)	(545)	(592)
Other interest	(171)	(100)	(405)	(213)
Total interest charges	(15,028)	(11,748)	(44,460)	(34,945)
Allowance for borrowed funds used during construction	3,993	211	8,645	640
Interest charges, net	<u>\$ (11,035)</u>	<u>\$ (11,537)</u>	<u>\$ (35,815)</u>	<u>\$ (34,305)</u>

Interest charges, net decreased for the three months ended September 30, 2015, by \$0.5 million, or 4.4%, as compared to the same period in 2014, due to the increase in allowance for borrowed funds used during construction, substantially offset by the increase in interest on long-term debt. Interest charges, net increased by \$1.5 million, or 4.4%, for the nine months ended September 30, 2015, as compared to the same period in 2014, primarily as a result of the increase in total interest charges due to the January 2015 debt issuance, substantially offset by the increase in allowance for borrowed funds used during construction.

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, increased for the three and nine months ended September 30, 2015, by \$0.7 million, or 27.9%, and \$1.9 million, or 27.2%, respectively, as compared to the same periods in 2014.

Financial Condition

The principal changes in our financial condition from December 31, 2014 to September 30, 2015, were caused by the increases in long-term debt, construction work in progress, accounts payable-members, accounts payable, and prepayments and other, the decrease in revolving credit facility, and the change in deferred energy.

- Long-term debt increased \$332.0 million due to issuance of long-term debt on January 15, 2015.
- Construction work in progress increased \$270.4 million primarily due to expenditures related to Wildcat Point.
- Accounts payable-members increased \$68.1 million due to the increase in member prepayments and the increase in amounts owed to our member distribution cooperatives under Margin Stabilization.
- Accounts payable increased \$46.2 million primarily due to increased payables related to Wildcat Point.
- Prepayments and other increased \$32.8 million primarily due to the \$35.5 million prepayment related to the purchase of the land and land rights associated with Wildcat Point.
- Revolving credit facility decreased \$86.0 million due to the repayment of outstanding borrowings under our revolving credit facility using proceeds from the January 2015 debt issuance.
- Deferred energy changed \$33.2 million as a result of the over-collection of our energy costs in 2015. The deferred energy balance changed from a \$19.9 million asset (under-collection) at December 31, 2014, to a \$13.2 million liability (over-collection) at September 30, 2015.

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 2015 and 2014, our operating activities provided cash flows of \$156.1 million and \$27.8 million, respectively. Operating activities in 2015 were primarily impacted by the following:

- Current liabilities changed \$75.8 million substantially due to the \$68.1 million increase in accounts payable-members;
- Deferred energy changed \$33.2 million due to the over-collection of our energy costs in 2015 as compared to the under-collection of our energy costs in 2014; and
- Current assets changed \$21.9 million due to the \$32.8 million change in prepayments and other, partially offset by changes in accounts receivable-members, fuel, materials, and supplies, and accounts receivable.

Revolving Credit Facility

We currently maintain a \$500.0 million revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019. At September 30, 2015, we did not have any borrowings outstanding under this facility, as compared to December 31, 2014, when we had \$86.0 million outstanding. At September 30, 2015, and December 31, 2014, we had letters of credit outstanding in the amount of \$8.2 million and \$10.0 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.

On January 15, 2015, we issued \$332.0 million of first mortgage bonds in a private placement transaction. The issuance consisted of \$260.0 million of 4.46% First Mortgage Bonds, 2015 Series A due December 1, 2044, and \$72.0 million of 4.56% First Mortgage Bonds, 2015 Series B due December 1, 2053.

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 2015.

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.

OLD DOMINION ELECTRIC COOPERATIVE

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. A hearing was held in December 2014, briefs were filed in January 2015, and 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 on May 13, 2015, and June 2, 2015, respectively. 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 2014 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. The results of FERC's further consideration of the matter cannot currently be determined and we have not recorded a receivable related to this matter.

Disposal of Coal Combustion Residual

In December 2014, the EPA issued the final rule regulating the disposal of CCRs, commonly known as coal ash. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act. The final rule was published in the Federal Register in April 2015 and, as a result, we established asset retirement obligations totaling \$8.6 million during the second quarter of 2015.

Capacity Performance

In December 2014, PJM proposed multiple changes to RPM and on June 9, 2015, FERC approved most of PJM's proposed changes. These changes are expected to result in higher capacity clearing prices and are intended to increase the availability of generating units, especially during emergency conditions. This could enable generation owners, such as ODEC, to earn increased compensation for capacity for certain generating units. While generating units have the potential to earn increased compensation for capacity, they are exposed to significantly higher charges if they do not perform during emergency conditions. For the PJM delivery year beginning June 1, 2016, qualifying generating units may be voluntarily offered into PJM's capacity auction as a capacity performance unit. A unit not offered as a capacity performance unit, known as a base capacity unit, will be excluded from the assessment of the charges for non-performance during the winter months. Starting with the delivery year beginning June 1, 2020, capacity revenue will only be paid to generating units offered as a capacity performance unit. We continue to evaluate our bidding strategy for our generating units for the PJM capacity auctions.

Amended Articles of Incorporation

On September 29, 2015, our members approved the Amended and Restated Articles of Incorporation. On October 6, 2015, the Virginia State Corporation Commission issued the Certificate of Amendment and Restatement, which caused the Amended and Restated Articles of Incorporation to become effective. The Amended and Restated Articles of Incorporation are filed as Exhibit 3.1. We have no class of equity securities registered under Section 12 of the Securities Exchange Act.

Clean Power Plan

On October 23, 2015, the EPA's Clean Power Plan rule was published in the Federal Register and, subject to a 60-day period to legally challenge the rule, will take effect December 23, 2015. The rule establishes emission guidelines for CO₂ from existing electric utility generating units under 111(d) of the Clean Air Act. We currently cannot predict the impact of EPA's Clean Power Plan rule on our existing facilities due to its implementation through state plans, or if none, a federal plan, each of which has not been developed. We continue to follow developments related to this rule.

ITEM 6.

EXHIBITS

3.1	Amended and Restated Articles of Incorporation
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

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, 2015

/s/ Robert L. Kees

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

EXHIBIT INDEX

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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, 2015

/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 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, 2015

/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 September 30, 2015 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, 2015

/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 September 30, 2015 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, 2015

/s/ ROBERT L. KEES

Robert L. Kees

Senior Vice President and Chief Financial Officer
(Principal financial officer)