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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 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	**23-7048405**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. employer identification no.)**
4201 Dominion Boulevard, Glen Allen, Virginia	**23060**
(Address of principal executive offices)	**(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 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:

Abbreviation or Acronym	Definition
Alstom	Alstom Power, Inc.
Bear Island	Bear Island Paper WB LLC
CCR	Coal combustion residual
Clover	Clover Power Station
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.
Virginia Power	Virginia Electric and Power Company
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

	June 30, 2015	December 31, 2014
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 1,709,560	$ 1,690,555
Less accumulated depreciation	(805,187)	(784,215)
Net Property, plant, and equipment	904,373	906,340
Nuclear fuel, at amortized cost	22,639	19,376
Construction work in progress	343,061	171,953
Net Electric Plant	1,270,073	1,097,669
Investments:		
Nuclear decommissioning trust	148,660	145,822
Lease deposits	100,632	99,191
Unrestricted investments and other	37,271	7,049
Total Investments	286,563	252,062
Current Assets:		
Cash and cash equivalents	161,135	1,424
Accounts receivable	7,278	8,656
Accounts receivable–deposits	400	—
Accounts receivable–members	94,130	83,108
Fuel, materials, and supplies	65,591	64,154
Deferred energy	18,254	19,948
Prepayments and other	7,144	5,131
Total Current Assets	353,932	182,421
Deferred Charges:		
Regulatory assets	84,407	87,987
Other	12,225	18,603
Total Deferred Charges	96,632	106,590
Total Assets	$ 2,007,200	$ 1,638,742
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 384,983	$ 379,097
Non-controlling interest	5,695	5,687
Total Patronage capital and Non-controlling interest	390,678	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	1,443,716	1,191,822
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	156,534	96,702
Accounts payable–members	65,674	35,217
Accrued expenses	7,443	4,568
Total Current Liabilities	257,943	164,779
Deferred Credits and Other Liabilities:		
Asset retirement obligations	115,877	104,936
Obligations under long-term lease	87,674	84,730
Regulatory liabilities	79,125	78,764
Other	22,865	13,711
Total Deferred Credits and Other Liabilities	305,541	282,141
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,007,200	$ 1,638,742

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 June 30,		Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
	(in thousands)		(in thousands)	
Operating Revenues	$ 249,341	$ 217,331	$ 541,597	$ 482,427
Operating Expenses:				
Fuel	35,652	29,098	79,228	144,627
Purchased power	107,155	102,180	296,433	273,346
Transmission	28,073	18,617	55,158	36,816
Deferred energy	25,671	16,469	1,694	(76,960)
Operations and maintenance	12,910	12,137	28,835	26,683
Administrative and general	9,974	11,091	20,491	22,453
Depreciation and amortization	11,527	10,498	22,201	21,004
Amortization of regulatory asset/(liability), net	792	965	1,586	2,798
Accretion of asset retirement obligations	1,292	1,019	2,372	2,038
Taxes, other than income taxes	2,081	2,136	4,192	4,307
Total Operating Expenses	235,127	204,210	512,190	457,112
Operating Margin	14,214	13,121	29,407	25,315
Other expense, net	(823)	(726)	(1,687)	(1,439)
Investment income	1,624	1,332	2,956	3,527
Interest charges, net	(12,012)	(11,397)	(24,780)	(22,768)
Income taxes	(2)	—	(2)	1
Net Margin including Non-controlling interest	3,001	2,330	5,894	4,636
Non-controlling interest	(9)	—	(8)	4
Net Margin attributable to ODEC	2,992	2,330	5,886	4,640
Patronage Capital - Beginning of Period	381,991	372,307	379,097	369,997
Patronage Capital - End of Period	$ 384,983	$ 374,637	$ 384,983	$ 374,637

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

OLD DOMINION ELECTRIC COOPERATIVE

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Six Months Ended June 30,	
	2015	2014
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	$ 5,894	$ 4,636
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	22,201	21,004
Other non-cash charges	9,113	9,235
Amortization of lease obligations	2,944	2,749
Interest on lease deposits	(1,441)	(1,407)
Change in current assets	(13,494)	(574)
Change in deferred energy	1,694	(76,960)
Change in current liabilities	25,469	(1,565)
Change in regulatory assets and liabilities	3,793	(1,242)
Change in deferred charges-other and deferred credits and other liabilities-other	5,239	(4,797)
Net Cash Provided by (Used for) Operating Activities	61,412	(48,921)
Investing Activities:		
Purchases of held to maturity securities	(130,000)	(2,000)
Proceeds from sale of held to maturity securities	100,000	20,000
Increase in other investments	(2,909)	(3,136)
Electric plant additions	(113,038)	(60,689)
Net Cash Used for Investing Activities	(145,947)	(45,825)
Financing Activities:		
Issuance of long-term debt	332,000	—
Debt issuance costs	(1,754)	—
Draws on revolving credit facility	104,000	119,704
Repayments on revolving credit facility	(190,000)	(62,704)
Net Cash Provided by Financing Activities	244,246	57,000
Net Change in Cash and Cash Equivalents	159,711	(37,746)
Cash and Cash Equivalents - Beginning of Period	1,424	51,669
Cash and Cash Equivalents - End of Period	$ 161,135	$ 13,923

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 June 30, 2015, our consolidated results of operations for the three and six months ended June 30, 2015 and 2014, and cash flows for the six months ended June 30, 2015 and 2014. The consolidated results of operations for the three and six months ended June 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 June 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.

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

	June 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)]	$ 148,660	$ 45,771	$ 102,889	$ —
Unrestricted investments and other [(3)]	203	—	203	—
Total Financial Assets	$ 148,863	$ 45,771	$ 103,092	$ —
Derivatives - gas and power [(4)]	$ 2,320	$ 2,320	$ —	$ —
Total Financial Liabilities	$ 2,320	$ 2,320	$ —	$ —

	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.

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

Commodity	Unit of Measure	As of June 30, 2015 Quantity	As of December 31, 2014 Quantity
Natural gas	MMBTU	7,660,000	5,610,000

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 June 30, 2015	Fair Value As of December 31, 2014
		(in thousands)	
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 2,320	$ 5,215
Total derivatives in a liability position		$ 2,320	$ 5,215

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three and Six Months Ended June 30, 2015 and 2014

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of June 30, 2015	2014	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 June 30, 2015	2014	Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Six Months Ended June 30, 2015	2014
	(in thousands)			(in thousands)		(in thousands)	
Natural gas futures contracts [1]	$ (4,663)	$ 141	Fuel	$ (952)	$ 295	$ (1,658)	$ 334
Purchased power	—	—	Purchased power	—	—	(14)	—
Total	$ (4,663)	$ 141	Total	$ (952)	$ 295	$ (1,672)	$ 334

(1) Includes $2.3 million of loss on NYMEX contracts designated for July 2015 that were physically sold in June 2015 and the impact on the Statement of Financial Position has been deferred until July 2015.

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 at June 30, 2015 and December 31, 2014:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
				(in thousands)		
June 30, 2015						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 42,362	$ 3,101	$ —	$ 45,463	$ 45,463
Equity securities	Available for sale	70,336	32,553	—	102,889	102,889
Cash and other	Available for sale	308	—	—	308	308
Total Nuclear Decommissioning Trust		$ 113,006	$ 35,654	$ —	$ 148,660	$ 148,660
Lease Deposits [2]						
Government obligations	Held to maturity	$ 100,632	$ 5,787	$ —	$ 106,419	$ 100,632
Total Lease Deposits		$ 100,632	$ 5,787	$ —	$ 106,419	$ 100,632
Unrestricted investments						
Government obligations	Held to maturity	$ 32,211	$ 7	$ (50)	$ 32,168	$ 32,211
Debt securities	Held to maturity	2,636	6	—	2,642	2,636
Total Unrestricted Investments		$ 34,847	$ 13	$ (50)	$ 34,810	$ 34,847
Other						
Equity securities	Trading	$ 152	$ 51	$ —	$ 203	$ 203
Non-marketable equity investments	Equity	2,221	1,984	—	4,205	2,221
Total Other		$ 2,373	$ 2,035	$ —	$ 4,408	$ 2,424
						$ 286,563
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		$ 110,316	$ 35,506	$ —	$ 145,822	$ 145,822
Lease Deposits [2]						
Government obligations	Held to maturity	$ 99,191	$ 5,569	$ —	$ 104,760	$ 99,191
Total Lease Deposits		$ 99,191	$ 5,569	$ —	$ 104,760	$ 99,191
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		$ 4,641	$ —	$ (18)	$ 4,623	$ 4,641
Other						
Equity securities	Trading	$ 151	$ 47	$ —	$ 198	$ 198
Non-marketable equity investments	Equity	2,210	1,821	—	4,031	2,210
Total Other		$ 2,361	$ 1,868	$ —	$ 4,229	$ 2,408
						$ 252,062

(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 June 30, 2015 and December 31, 2014, were as follows:

Description	June 30, 2015 Cost	June 30, 2015 Carrying Value	December 31, 2014 Cost	December 31, 2014 Carrying Value
	(in thousands)			
Available for sale	$ 113,006	$ 148,660	$ 110,316	$ 145,822
Held to maturity	135,479	135,479	103,832	103,832
Equity	2,221	2,221	2,210	2,210
Trading	152	203	151	198
	$ 250,858	$ 286,563	$ 216,509	$ 252,062

Contractual maturities of debt securities at June 30, 2015, 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)	$ —	$ —	$ 45,463	$ —	$ 45,463
Held to maturity	30,731	104,667	82	—	135,480
	$ 30,731	$ 104,667	$ 45,545	$ —	$ 180,943

(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 and are currently accounting for it 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. The ground lease will remain in effect until title transfer, which we anticipate will occur in the third quarter of 2015. As a result of the agreement to purchase the land and land rights, we have adjusted the amortization period of the ground lease and have recorded $4.2 million as prepaid rent at June 30, 2015. The prepayment will either be expensed in the third quarter of 2015 or we will establish a regulatory asset. 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 June 30, 2015, we capitalized construction costs related to Wildcat Point totaling $292.3 million, including $3.9 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. 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 June 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 June 30, 2015, and December 31, 2014, we had letters of credit outstanding in the amount of $10.2 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.

Subsequent Event

In June 2015, our Board of Directors approved a decrease to our total energy rate of approximately 2.9%, effective July 1, 2015. This decrease was implemented due to changes in our realized as well as projected energy costs.

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 June 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 six months ended June 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 second 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 June 30, 2015, our deferred energy balance was an under-collection of $18.3 million.

- We continue with the construction of Wildcat Point (see "Wildcat Point Generation Facility" below). Through June 30, 2015, we capitalized construction costs totaling $292.3 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. Additionally, we invested a portion of the proceeds which will be used to fund Wildcat Point expenditures in the future.

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 and are currently accounting for it 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. The ground lease will remain in effect until title transfer, which we anticipate will occur in the third quarter of 2015. As a result of the agreement to purchase the land and land rights, we have adjusted the amortization period of the ground lease and have recorded $4.2 million as prepaid rent at June 30, 2015. The prepayment will either be expensed in the third quarter of 2015 or we will establish a regulatory asset. 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 June 30, 2015, we capitalized construction costs related to Wildcat Point totaling $292.3 million, including $3.9 million of capitalized interest.

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.

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 six months ended June 30, 2015, we recorded an increase in operating revenues of $4.2 million, and a reduction in operating revenues of $6.9 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges. For the three and six months ended June 30, 2014, we recorded an increase in operating revenues of $5.1 million and a reduction in operating revenues of $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 six months ended June 30, 2015 and 2014, were as follows:

	Three Months Ended June 30,		%	Six Months Ended June 30,		%
	2015	2014	Change	2015	2014	Change
Heating degree days	139	176	(21.0)	2,708	2,607	3.9
Cooling degree days	453	320	41.6	453	320	41.6

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 six months ended June 30, 2015 and 2014, were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015		2014		2015		2014	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	558,291	17.3%	624,155	21.9%	1,213,105	16.6%	1,310,907	19.2%
North Anna	481,407	14.9	489,963	17.2	899,790	12.3	975,280	14.3
Louisa	103,019	3.2	25,168	0.9	154,035	2.1	146,537	2.1
Marsh Run	237,471	7.4	78,715	2.7	327,415	4.4	249,321	3.6
Rock Springs	102,331	3.2	23,247	0.8	108,006	1.5	50,122	0.7
Distributed Generation	217	—	53	—	554	—	1,992	—
Total Generated	1,482,736	46.0	1,241,301	43.5	2,702,905	36.9	2,734,159	39.9
Purchased:								
Other than renewable:								
Long-term and short-term	1,468,287	45.6	1,210,712	42.4	3,837,566	52.4	3,089,942	45.1
Spot market	101,028	3.1	232,145	8.1	361,026	5.0	613,170	9.0
Total Other than renewable	1,569,315	48.7	1,442,857	50.5	4,198,592	57.4	3,703,112	54.1
Renewable [(1)]	171,055	5.3	169,857	6.0	417,691	5.7	410,311	6.0
Total Purchased	1,740,370	54.0	1,612,714	56.5	4,616,283	63.1	4,113,423	60.1
Total Available Energy	3,223,106	100.0%	2,854,015	100.0%	7,319,188	100.0%	6,847,582	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 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Clover	74.7%	79.7%	75.2%	79.3%
North Anna	98.6	100.0	92.9	99.6
Louisa	99.4	93.2	97.1	96.3
Marsh Run	93.0	96.7	96.1	98.2
Rock Springs	99.4	94.6	98.6	96.7

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Clover	59.4%	66.2%	64.8%	69.8%
North Anna	100.4	102.2	94.4	102.3

The scheduled and unscheduled outages for Clover and North Anna for the three and six months ended June 30, 2015 and 2014, were as follows:

	Clover				North Anna			
	Three Months Ended June 30,		Six Months Ended June 30,		Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	(in days)				(in days)			
Scheduled	39.2	34.5	81.4	65.4	—	—	20.5	—
Unscheduled	7.0	2.7	8.4	9.6	2.5	—	5.3	1.3
Total	46.2	37.2	89.8	75.0	2.5	—	25.8	1.3

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 six months ended June 30, 2015 and 2014, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Revenues from sales to:				
Member distribution cooperatives				
Energy revenues [1]	$ 136,386	$ 128,459	$ 325,830	$ 288,644
Demand revenues	91,340	80,315	185,460	162,447
Total revenues from sales to member distribution cooperatives	227,726	208,774	511,290	451,091
Non-members [2]	21,615	8,557	30,307	31,336
Total operating revenues	$ 249,341	$ 217,331	$ 541,597	$ 482,427
Average cost of energy to member distribution cooperatives (per MWh)	$ 48.76	$ 47.40	$ 48.56	$ 44.38
Average cost of demand to member distribution cooperatives (per MWh)	32.66	29.64	27.64	24.98
Average total cost to member distribution cooperatives (per MWh)	$ 81.42	$ 77.04	$ 76.20	$ 69.36

(1) Includes sales of renewable energy credits of $1.2 million and $1.4 million, for the three and six months ended June 30, 2015, respectively, and $0.5 million for the three and six months ended June 30, 2014.

(2) Includes sales of renewable energy credits of $6.6 million and $7.5 million for the three and six months ended June 30, 2015, respectively, and $3.2 million and $3.7 million for the three and six months ended June 30, 2014, respectively.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	2,797,082	2,709,843	6,709,191	6,503,437
Non-members	407,920	125,533	574,556	295,396
Total energy sales	3,205,002	2,835,376	7,283,747	6,798,833

Our energy sales in MWh to our member distribution cooperatives for the three and six months ended June 30, 2015, were 3.2% higher, as compared to the same periods in 2014.

Our energy sales in MWh to non-members for the three and six months ended June 30, 2015, were 225.0% and 94.5% 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 June 30, 2015, increased $19.0 million, or 9.1%, as compared to the same period in 2014, substantially due to the $11.0 million, or 13.7% , increase in demand revenues, primarily due to increased transmission expenses. Additionally, MWh sales to our member distribution cooperatives increased 3.2%, and the average cost of energy sold to our member distribution cooperatives increased 2.9%. Total revenues from sales to our member distribution cooperatives for the six months ended June 30, 2015, increased $60.2 million, or 13.3%, as compared to the same period in 2014, substantially due to the $37.2 million, or 12.9%, increase in energy revenues. The increase in energy revenues is due to the 9.4% increase in the average cost of energy sold to our member distribution cooperatives and the 3.2% increase in the volume of MWh sales. Additionally, demand revenues increased $23.0 million, or 14.2%, primarily due to increased transmission expenses.

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 and six months ended June 30, 2015, was 5.7% and 9.9% higher, respectively, as compared to the same periods in 2014, primarily as a result of net increases in our total energy rate. There was also 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)

Non-member revenue for the three months ended June 30, 2015, increased $13.1 million, or 152.6%, as compared to the same period in 2014, due to a 180.3% increase in revenue from sales of excess energy and a 106.3% increase in revenue from sales of renewable energy credits. The increase in revenue from sales of excess energy was due to a 225.0% increase in the volume of excess energy sales partially offset by a 13.7% decrease in the average price of excess energy. Non-member revenue for the six months ended June 30, 2015, decreased $1.0 million, or 3.3%, as compared to the same period in 2014, due to the 57.6% decrease in the average price of excess energy, substantially offset by the 94.5% increase in the volume of excess energy sales.

Operating Expenses

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Fuel	$ 35,652	$ 29,098	$ 79,228	$ 144,627
Purchased power	107,155	102,180	296,433	273,346
Transmission	28,073	18,617	55,158	36,816
Deferred energy	25,671	16,469	1,694	(76,960)
Operations and maintenance	12,910	12,137	28,835	26,683
Administrative and general	9,974	11,091	20,491	22,453
Depreciation and amortization	11,527	10,498	22,201	21,004
Amortization of regulatory asset/(liability), net	792	965	1,586	2,798
Accretion of asset retirement obligations	1,292	1,019	2,372	2,038
Taxes, other than income taxes	2,081	2,136	4,192	4,307
Total Operating Expenses	$ 235,127	$ 204,210	$ 512,190	$ 457,112

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 $30.9 million, or 15.1%, and $55.1 million, or 12.0%, for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014. The increase for the three months ended June 30, 2015, was primarily due to increases in transmission expense, deferred energy expense, fuel expense, and purchased power expense. The increase for the six months ended June 30, 2015, was primarily due to increases in deferred energy expense, purchased power expense, and transmission expense, partially offset by the decrease in fuel expense.

- Transmission expense increased $9.5 million, or 50.8%, and $18.3 million, or 49.8%, for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014 primarily due to an increase in PJM charges for network transmission services.

- Deferred energy expense increased $9.2 million and $78.7 million for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014. For the three months ended June 30, 2015 and 2014, we over-collected $25.7 million and $16.5 million, respectively. For six months ended June 30, 2015, we over-collected $1.7 million whereas for the six months ended June 30, 2014, we under-collected $77.0 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.

- Fuel expense increased $6.6 million, or 22.5%, for the three months ended June 30, 2015, as compared to the same period in 2014 primarily due to the 248.3% increase in the dispatch of our combustion turbine facilities offset by the 34.9% decrease in the average cost of fuel for our combustion turbine facilities. Fuel expense decreased $65.4 million, or 45.2%, for the six months ended June 30, 2015, as compared to the same period in 2014. This decrease was primarily driven by the 74.4% decrease in the average cost of fuel for our combustion turbine facilities partially offset by the 32.2% increase in the dispatch of our combustion turbine facilities.

- Purchased power expense, which includes the cost of purchased energy and capacity, increased $5.0 million, or 4.9%, and $23.1 million, or 8.4%, for the three and six months ended June 30, 2015, respectively, as compared to the same periods in 2014. The volume of purchased energy increased 7.9% and 12.2%, for the three and six months ended June 30, 2015, respectively, partially offset by the 4.4% and 2.9% decrease in the the average cost of purchased energy for the three and six months ended June 30, 2015, respectively.

Other Items

Investment Income

Investment income increased for the three months ended June 30, 2015, by $0.3 million, or 21.9%, as compared to the same period in 2014, primarily due to higher investment balances as a result of excess cash from the January 2015 debt issuance. Investment income decreased for the six months ended June 30, 2015, by $0.6 million, or 16.2%, as compared to the same period 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 six months ended June 30, 2015 and 2014, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in thousands)		(in thousands)	
Interest on long-term debt	$ (14,702)	$ (11,385)	$ (28,817)	$ (22,755)
Interest on revolving credit facility	(124)	(199)	(381)	(329)
Other interest	(133)	(63)	(234)	(113)
Total interest charges	(14,959)	(11,647)	(29,432)	(23,197)
Allowance for borrowed funds used during construction	2,947	250	4,652	429
Interest charges, net	$ (12,012)	$ (11,397)	$ (24,780)	$ (22,768)

Interest charges, net increased for the three and six months ended June 30, 2015, by $0.6 million, or 5.4%, and $2.0 million, or 8.8%, respectively, as compared to the same periods 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 six months ended June 30, 2015, by $0.7 million, or 28.4%, and $1.2 million, or 26.9%, respectively, as compared to the same periods in 2014.

Financial Condition

The principal changes in our financial condition from December 31, 2014 to June 30, 2015, were caused by the increases in long-term debt, construction work in progress, accounts payable, accounts payable-members, unrestricted investments and other, accounts receivable-members, asset retirement obligations, and deferred credits and other liabilities-other, partially offset by the decrease in revolving credit facility.

- Long-term debt increased $332.0 million due to issuance of long-term debt on January 15, 2015.
- Construction work in progress increased $171.1 million primarily due to expenditures related to Wildcat Point.
- Accounts payable increased $59.8 million primarily due to increased payables related to Wildcat Point.
- Accounts payable-members increased $30.5 million due to the increase in member prepayments and the increase in amounts owed to our member distribution cooperatives under Margin Stabilization.
- Unrestricted investments and other increased $30.2 million as a result of the investment of excess cash generated by the long-term debt issuance in January 2015.
- 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.

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 six months of 2015, our operating activities provided cash flows of $61.4 million and for the first six months of 2014, our operating activities used cash flows of $48.9 million. Operating activities in 2015 were primarily impacted by the $25.5 million change in current liabilities substantially due to the $30.5 million increase in accounts payable–members.

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 June 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 June 30, 2015, and December 31, 2014, we had letters of credit outstanding in the amount of $10.2 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 second 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 of 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 are currently evaluating our bidding strategy for our generating units in the PJM capacity auctions.

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

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

Date: August 12, 2015

/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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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: August 12, 2015

/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: August 12, 2015

/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 June 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: August 12, 2015

/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 June 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: August 12, 2015

/s/ ROBERT L. KEES

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