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

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2014

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 X

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 X 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	X	Smaller reporting company	___

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

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
CAIR	Clean Air Interstate Rule
Clover	Clover Power Station
CPCN	Certificate of Public Convenience and Necessity
CSAPR	Cross State Air Pollution Rule
EPC	Engineering, procurement, and construction
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
Mitsubishi	Mitsubishi Hitachi Power Systems Americas, Inc.
MPSC	Maryland Public Service Commission
MW	Megawatt(s)
MWh	Megawatt hour(s)
North Anna	North Anna Nuclear Power Station
ODEC, We, Our	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
REC	Rappahannock Electric Cooperative
RFP	Request for proposal
RTO	Regional transmission organization
TEC	TEC Trading, Inc.
Wildcat Point	Wildcat Point Generation Facility
XBRL	Extensible Business Reporting Language

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OLD DOMINION ELECTRIC COOPERATIVE
PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS
CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2014	December 31, 2013
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 1,663,467	$ 1,660,548
Less accumulated depreciation	(771,441)	(755,288)
	892,026	905,260
Nuclear fuel, at amortized cost	16,797	23,636
Construction work in progress	88,500	36,482
Net Electric Plant	997,323	965,378
Investments:		
Nuclear decommissioning trust	143,169	134,454
Lease deposits	98,041	96,634
Unrestricted investments and other	6,635	24,896
Total Investments	247,845	255,984
Current Assets:		
Cash and cash equivalents	13,923	51,669
Accounts receivable	7,872	12,742
Accounts receivable–deposits	-	4,400
Accounts receivable–members	89,147	88,545
Fuel, materials, and supplies	59,585	49,246
Deferred energy	39,767	-
Prepayments and other	2,795	3,892
Total Current Assets	213,089	210,494
Deferred Charges:		
Regulatory assets	85,236	87,983
Other	17,331	10,758
Total Deferred Charges	102,567	98,741
Total Assets	$ 1,560,824	$ 1,530,597
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 374,637	$ 369,997
Non-controlling interest	5,686	5,691
Total Patronage capital and Non-controlling interest	380,323	375,688
Long-term debt	806,330	749,330
Total Capitalization	1,186,653	1,125,018
Current Liabilities:		
Long-term debt due within one year	28,292	28,292
Accounts payable	60,379	68,560
Accounts payable–members	30,256	24,998
Accrued expenses	6,349	4,991
Deferred energy	-	37,193
Total Current Liabilities	125,276	164,034
Deferred Credits and Other Liabilities:		
Asset retirement obligations	82,898	80,860
Obligations under long-term lease	81,976	79,227
Regulatory liabilities	78,262	76,940
Other	5,759	4,518
Total Deferred Credits and Other Liabilities	248,895	241,545
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$ 1,560,824	$ 1,530,597

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,	
	2014	**2013**	**2014**	**2013**
	(in thousands)		(in thousands)	
Operating Revenues	$ 217,331	$ 187,623	$ 482,427	$ 408,336
Operating Expenses:				
Fuel	29,098	30,317	144,627	61,769
Purchased power	120,797	118,007	310,162	266,659
Deferred energy	16,469	(11,280)	(76,960)	(18,030)
Operations and maintenance	12,137	11,774	26,683	19,860
Administrative and general	11,091	10,655	22,453	21,447
Depreciation and amortization	10,498	10,569	21,004	21,209
Amortization of regulatory asset/(liability), net	965	1,272	2,798	1,584
Accretion of asset retirement obligations	1,019	995	2,038	1,990
Taxes, other than income taxes	2,136	2,184	4,307	4,416
Total Operating Expenses	204,210	174,493	457,112	380,904
Operating Margin	13,121	13,130	25,315	27,432
Other expense, net	(726)	(648)	(1,439)	(1,301)
Investment income	1,332	1,610	3,527	2,268
Interest charges, net	(11,397)	(11,685)	(22,768)	(23,580)
Income taxes	-	(16)	1	(21)
Net Margin including Non-controlling interest	2,330	2,391	4,636	4,798
Non-controlling interest	-	(45)	4	(66)
Net Margin attributable to ODEC	2,330	2,346	4,640	4,732
Patronage Capital - Beginning of Period	372,307	362,810	369,997	360,424
Patronage Capital - End of Period	$ 374,637	$ 365,156	$ 374,637	$ 365,156

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, 2014	Six Months Ended June 30, 2013
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	$ 4,636	$ 4,798
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	21,004	21,209
Other non-cash charges	9,235	9,778
Amortization of lease obligations	2,749	2,569
Interest on lease deposits	(1,407)	(1,373)
Change in current assets	(574)	26,768
Change in deferred energy	(76,960)	(18,030)
Change in current liabilities	(1,565)	(17,891)
Change in regulatory assets and liabilities	(1,242)	(12,055)
Change in deferred charges and credits	(4,797)	(430)
Net Cash (Used for) Provided by Operating Activities	(48,921)	15,343
Investing Activities:		
Purchases of held to maturity securities	(2,000)	-
Proceeds from sale of held to maturity securities	20,000	53,117
Increase in other investments	(3,136)	(2,080)
Electric plant additions	(60,689)	(12,347)
Net Cash (Used for) Provided by Investing Activities	(45,825)	38,690
Financing Activities:		
Issuance of long-term debt	-	100,000
Debt issuance costs	-	(744)
Payment of long-term debt	-	(60,535)
Draws on revolving credit facility	119,704	-
Repayments on revolving credit facility	(62,704)	-
Net Cash Provided by Financing Activities	57,000	38,721
Net Change in Cash and Cash Equivalents	(37,746)	92,754
Cash and Cash Equivalents - Beginning of Period	51,669	37,343
Cash and Cash Equivalents - End of Period	$ 13,923	$ 130,097

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, 2014, our consolidated results of operations for the three and six months ended June 30, 2014 and 2013, and cash flows for the six months ended June 30, 2014 and 2013. The consolidated results of operations for the three and six months ended June 30, 2014, 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 2013 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, 2014 and December 31, 2013. 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.

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, 2014 and December 31, 2013:

	June 30, 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]	$ 143,169	$ 44,875	$ 98,294	$ -
Unrestricted investments and other [3]	180	180	-	-
Total Financial Assets	$ 143,349	$ 45,055	$ 98,294	$ -
Derivatives - gas and power [4]	$ 123	$ 123	$ -	$ -
Total Financial Liabilities	$ 123	$ 123	$ -	$ -

	December 31, 2013	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]	$ 134,454	$ 42,661	$ 91,793	$ -
Unrestricted investments and other [3]	173	173	-	-
Derivatives - gas and power [4]	412	412	-	-
Total Financial Assets	$ 135,039	$ 43,246	$ 91,793	$ -

(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 charges–other, if an asset, or in deferred credits and liabilities–other, if a liability, and which are indexed against NYMEX. For additional information about our derivative financial instruments, see Notes 1 and 4 of the Notes to Consolidated Financial Statements in our 2013 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 2013 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, 2014 Quantity	As of December 31, 2013 Quantity
Natural Gas	MMBTU	5,530,000	1,470,000

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

		Fair Value	
	Balance Sheet Location	**As of June 30, 2014**	**As of December 31, 2013**
		(in thousands)	
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges-other	$ -	$ 412
Total derivatives in an asset position		$ -	$ 412
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 123	$ -
Total derivatives in a liability position		$ 123	$ -

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, 2014 and 2013

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of June 30,		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,		Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Six Months Ended June 30,	
	2014	**2013**		**2014**	**2013**	**2014**	**2013**
	(in thousands)			(in thousands)		(in thousands)	
Natural gas futures contracts [(1)]	$ 141	$ (2,314)	Fuel	$ 295	$ (687)	$ 334	$ (687)
Total	$ 141	$ (2,314)		$ 295	$ (687)	$ 334	$ (687)

(1) As of June 30, 2014 and 2013, includes a regulatory liability of $0.3 million and a regulatory asset of $1.7 million, respectively, to be recognized in future periods as the result of the contracts being effectively settled.

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 this occurs, we may be forced to enter into alternative contractual arrangements or purchase energy in the forward, short-term, or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

4. *Investments*

Investments were as follows at June 30, 2014 and December 31, 2013:

Description	Designation	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
				(in thousands)		
June 30, 2014						
Nuclear decommissioning trust [1]						
Debt securities	Available for sale	$ 41,002	$ 3,370	$ -	$ 44,372	$ 44,372
Equity securities	Available for sale	65,133	33,161	-	98,294	98,294
Cash and other	Available for sale	503	-	-	503	503
Total Nuclear Decommissioning Trust		$ 106,638	$ 36,531	$ -	$ 143,169	$ 143,169
Lease Deposits [3]						
Government obligations	Held to maturity	$ 98,041	$ 6,202	$ -	$ 104,243	$ 98,041
Total Lease Deposits		$ 98,041	$ 6,202	$ -	$ 104,243	$ 98,041
Unrestricted investments						
Government obligations	Held to maturity	$ 2,006	$ 1	$ -	$ 2,007	$ 2,006
Debt securities	Held to maturity	2,200	-	-	2,200	2,200
Total Unrestricted Investments		$ 4,206	$ 1	$ -	$ 4,207	$ 4,206
Other						
Equity securities	Trading	$ 131	$ 49	$ -	$ 180	$ 180
Non-marketable equity investments	Equity	2,249	1,813	-	4,062	2,249
Total Other		$ 2,380	$ 1,862	$ -	$ 4,242	$ 2,429
						$ 247,845
December 31, 2013						
Nuclear decommissioning trust [1][2]						
Debt securities	Available for sale	$ 40,352	$ 1,719	$ -	$ 42,071	$ 42,071
Equity securities	Available for sale	62,293	29,500	-	91,793	91,793
Cash and other	Available for sale	590	-	-	590	590
Total Nuclear Decommissioning Trust		$ 103,235	$ 31,219	$ -	$ 134,454	$ 134,454
Lease Deposits [3]						
Government obligations	Held to maturity	$ 96,634	$ 5,676	$ -	$ 102,310	$ 96,634
Total Lease Deposits		$ 96,634	$ 5,676	$ -	$ 102,310	$ 96,634
Unrestricted investments						
Government obligations	Held to maturity	$ 20,174	$ 1	$ -	$ 20,175	$ 20,174
Debt securities	Held to maturity	2,200	-	(4)	2,196	2,200
Total Unrestricted Investments		$ 22,374	$ 1	$ (4)	$ 22,371	$ 22,374
Other						
Equity securities	Trading	$ 131	$ 42	$ -	$ 173	$ 173
Non-marketable equity investments	Equity	2,349	1,735	-	4,084	2,349
Total Other		$ 2,480	$ 1,777	$ -	$ 4,257	$ 2,522
						$ 255,984

(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 2013 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) In the fourth quarter of 2013 we rebalanced our portfolio in the nuclear decommissioning trust.

(3) 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 2013 Annual Report on Form 10-K.

Our investments by classification at June 30, 2014 and December 31, 2013, were as follows:

Description	June 30, 2014 Cost	June 30, 2014 Carrying Value	December 31, 2013 Cost	December 31, 2013 Carrying Value
	(in thousands)			
Available for sale	$ 106,638	$ 143,169	$ 103,235	$ 134,454
Held to maturity	102,247	102,247	119,008	119,008
Equity	2,249	2,249	2,349	2,349
Trading	131	180	131	173
	$ 211,265	$ 247,845	$ 224,723	$ 255,984

Contractual maturities of debt securities at June 30, 2014, 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]	$ -	$ -	$ 44,372	$ -	$ 44,372
Held to maturity	1,763	100,243	241	-	102,247
	$ 1,763	$ 100,243	$ 44,613	$ -	$ 146,619

[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*

Margin Stabilization

Margin Stabilization allows us to review our actual demand-related costs of service and demand revenue and adjust revenues from our member distribution cooperatives to meet our financial coverage requirements and accumulate additional equity as approved by our board of directors. Our formula rate allows us to recover and refund amounts utilizing Margin Stabilization. Pursuant to FERC's acceptance of the revisions to the formula rate as issued in FERC's December 2, 2013 order (see "FERC Proceeding Related to Formula Rate" below), 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 required.

- 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, 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. For the three and six months ended June 30, 2013, we recorded an increase in operating revenues of $6.5 million and a reduction in operating revenues of $8.3 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.

Three and Six Months Ended June 2014 Results and the Impact on Deferred Energy

Deferred energy expense represents the difference between energy revenues, which are based upon energy rates approved by our board of directors, and energy expenses, which are based upon actual energy costs incurred. In the three months ended June 30, 2014, we over-collected energy costs from our member distribution cooperatives by $16.5 million. In the six months ended June 30, 2014, we under-collected energy costs from our member distribution cooperatives by $77.0 million. As a result, our deferred energy balance changed from an over-collection of $37.2 million at December 31, 2013, to an under-collection of $39.8 million at June 30, 2014. This under-collection was driven by first quarter 2014 results when the entire mid-Atlantic region experienced extremely cold weather, which increased our energy sales in MWh to our member distribution cooperatives 10.2% over the expected requirements, and which had a significant effect on our fuel and purchased power costs. To address the under-collection of energy costs, we increased our total energy rate 11.8% effective April 1, 2014.

Wildcat Point Generation Facility

On April 23, 2013, we announced our intention to seek approval to develop and construct a 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 we anticipate permanent construction will begin in late 2014, and the facility will become operational in mid-2017.

Wildcat Point will consist of two combustion turbines, two heat recovery steam generators and one steam turbine generator. Mitsubishi will supply the combustion turbines and Alstom will supply the heat recovery steam generators and the 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. For the three months ended June 30, 2014 and 2013, we expensed $2.0 million and $2.1 million, respectively, of non-capital costs related to Wildcat Point, which are recorded in administrative and general expense. For the six months ended June 30, 2014 and 2013, we expensed $3.8 million and $3.1 million, respectively, of non-capital costs related to Wildcat Point. Through June 30, 2014, we capitalized progress payments for major equipment, EPC payments, emission reduction credits, and land and land rights totaling $38.9 million, which are recorded in construction work in progress.

FERC Proceeding Related to Formula Rate

On September 30, 2013, we filed with FERC to revise our cost-based formula rate 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. Settlement discussions have been terminated and a litigation schedule has been set with a hearing date of December 9, 2014. The Presiding Judge has referred the parties to dispute resolution procedures with the assistance of FERC Dispute Resolution Service. Discussions are ongoing, parallel with the hearing procedures.

Recovery of Costs from PJM

During the second quarter of 2014, we recovered from PJM $2.1 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 23, 2014, we filed a petition at FERC seeking recovery from PJM of additional unreimbursed costs totaling approximately $14.9 million. The results of our efforts 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, five-year revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019, unless earlier terminated in accordance with the agreement. At June 30, 2014, we had $57.0 million in borrowings outstanding under this facility, which are recorded in long-term debt. Additionally, at June 30, 2014, we had a letter of credit in the amount of $7.0 million outstanding. At December 31, 2013, we did not have any borrowings or letters of credit outstanding under this facility.

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, 2014, there have been no significant changes in our critical accounting policies as disclosed in our 2013 Annual Report on Form 10-K. These policies include the accounting for rate regulation, 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 six months ended June 30, 2014, were still significantly impacted by the extremely cold weather experienced by the entire mid-Atlantic region during the first quarter of 2014, which increased energy sales and fuel and purchased power expense, and changed our deferred energy balance from an over-collection to an under-collection. Our average energy cost increased 9.7%, primarily driven by the $82.9 million increase in fuel expense and the $43.5 million increase in purchased power expense. The increase in fuel expense was primarily impacted by the 279.5% increase in the dispatch of our combustion turbine facilities as well as the 213.3% increase in the average cost of fuel for our combustion turbine facilities. The increase in purchased power expense was driven by the 13.3% increase in the average cost of purchased energy and the 2.7% increase in the volume of purchased energy. In the three months ended June 30, 2014, we over-collected energy costs from our member distribution cooperatives by $16.5 million, and for the six months ended June 30, 2014, we under-collected energy costs from our member distribution cooperatives by $77.0 million. Any over-or under-collection of energy costs is recorded as deferred energy expense. As a result, our deferred energy balance, which represents the cumulative difference between energy revenues and energy expenses, changed from an over-collection of $37.2 million at December 31, 2013, to an under-collection of $39.8 million at June 30, 2014. To address the under-collection of energy costs, we increased our total energy rate 11.8% effective April 1, 2014. 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 2013 Annual Report on Form 10-K.

Wildcat Point Generation Facility

On April 23, 2013, we announced our intention to seek approval to develop and construct a 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 we anticipate permanent construction will begin in late 2014, and the facility will become operational in mid-2017.

Wildcat Point will consist of two combustion turbines, two heat recovery steam generators and one steam turbine generator. Mitsubishi will supply the combustion turbines and Alstom will supply the heat recovery steam generators and the 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. For the three months ended June 30, 2014 and 2013, we expensed $2.0 million and $2.1 million, respectively, of non-capital costs related to Wildcat Point, which are recorded in administrative and general expense. For the six months ended June 30, 2014 and 2013, we expensed $3.8 million and $3.1 million, respectively, of non-capital costs related to Wildcat Point. Through June 30, 2014, we capitalized progress payments for major equipment, EPC payments, emission reduction credits, and land and land rights totaling $38.9 million, which are recorded in construction work in progress.

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. Through December 31, 2013, the base energy rate was a fixed rate that required FERC approval prior to adjustment. To the extent the base energy rate over- or under-collected our energy costs, we refunded or collected the difference through an energy adjustment rate. We reviewed our energy costs at least every six months to determine whether the base energy rate and the current energy adjustment rate together were recovering our actual and anticipated energy costs, and revised the energy adjustment rate accordingly. 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 will be 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 Part II, Item 1 below.

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. Through December 31, 2013, we collected our total demand costs through a single demand rate. 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 RTO members

- 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. Through December 31, 2013, utilizing Margin Stabilization, we adjusted our operating revenues to reflect actual demand costs incurred, including a net margin attributable to ODEC equal to 20% of actual 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 required.

- 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, 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. For the three and six months ended June 30, 2013, we recorded an increase in operating revenues of $6.5 million and a reduction in operating revenues of $8.3 million, respectively, utilizing Margin Stabilization, to produce a net margin equal to 20% of our actual total interest charges.

Weather

Weather is one factor that affects the demand for electricity. Weather also plays a role in the price of market energy through its effects on the market prices for fuel, particularly natural gas. Heating degree days are a measurement tool used to quantify the need to utilize heat for a building, and cooling degree days are a measurement tool used to quantify the need to utilize cooling for a building. The heating and cooling degree data is compiled utilizing various weather stations. Weather stations can be added or changed during the year, which may result in updates to previously reported data. The heating degree days and cooling degree days for the three and six months ended June 30, 2014 and 2013, were as follows:

	Three Months Ended June 30,		%	Six Months Ended June 30,		%
	2014	2013	Change	2014	2013	Change
Heating degree days	176	118	49.2	2,607	2,264	15.2
Cooling degree days	320	282	13.5	320	282	13.5

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, 2014 and 2013, were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	(in MWh and percentages)				(in MWh and percentages)			
Generated:								
Clover	624,155	21.9%	694,721	24.6%	1,310,907	19.2%	1,444,552	22.5%
North Anna	489,963	17.2	356,918	12.7	975,280	14.3	848,122	13.2
Louisa	25,168	0.9	20,148	0.7	146,537	2.1	37,568	0.6
Marsh Run	78,715	2.7	38,947	1.4	249,321	3.6	64,484	1.0
Rock Springs	23,247	0.8	15,461	0.5	50,122	0.7	15,461	0.3
Distributed Generation	53	-	11	-	1,992	-	34	-
Total Generated	1,241,301	43.5	1,126,206	39.9	2,734,159	39.9	2,410,221	37.6
Purchased:								
Other than renewable:								
Long-term and short-term	1,210,712	42.4	1,297,689	46.0	3,089,942	45.1	3,033,342	47.3
Spot market	232,145	8.1	208,399	7.4	613,170	9.0	543,720	8.4
Total Other than renewable	1,442,857	50.5	1,506,088	53.4	3,703,112	54.1	3,577,062	55.7
Renewable (1)	169,857	6.0	189,097	6.7	410,311	6.0	428,084	6.7
Total Purchased	1,612,714	56.5	1,695,185	60.1	4,113,423	60.1	4,005,146	62.4
Total Available Energy	2,854,015	100.0%	2,821,391	100.0%	6,847,582	100.0%	6,415,367	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 for system reliability purposes. For further discussion on PJM, see “Business—Power Supply Resources—PJM” in Item 1 of our 2013 Annual Report on Form 10-K. Owners of power plants incur the fixed costs of these facilities whether or not the units operate.

As previously mentioned, our generating facilities are under dispatch control of PJM. Typically, nuclear facilities are almost always dispatched and coal-fired and combustion turbine facilities are dispatched based upon economic factors including the market price of energy, and to meet reliability requirements. The operational availability of our owned generating resources for the three and six months ended June 30, 2014 and 2013, was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Clover	79.7%	91.4%	79.3%	95.7%
North Anna	100.0	74.7	99.6	87.3
Louisa	93.2	99.3	96.3	99.2
Marsh Run	96.7	99.9	98.2	99.1
Rock Springs	94.6	100.0	96.7	98.1

The output of Clover and North Anna for the three and six months ended June 30, 2014 and 2013 as a percentage of maximum dependable capacity rating of the facilities was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Clover	66.2%	73.6%	69.8%	76.9%
North Anna	102.2	74.6	102.3	89.0

The scheduled and unscheduled outages for Clover and North Anna for the three and six months ended June 30, 2014 and 2013 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,	
	2014	**2013**	**2014**	**2013**	**2014**	**2013**	**2014**	**2013**
	(in days)				(in days)			
Scheduled	34.5	15.7	65.4	15.7	-	32.5	-	32.5
Unscheduled	2.7	-	9.6	-	-	14.1	1.3	14.1
Total	37.2	15.7	75.0	15.7	-	46.6	1.3	46.6

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 2014 and 2013, 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, 2014 and 2013, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Revenues from sales to:	(in thousands)		(in thousands)	
Member distribution cooperatives				
Energy revenues [1]	$ 128,459	$ 106,140	$ 288,644	$ 247,959
Demand revenues	80,315	74,979	162,447	148,962
Total revenues from sales to member distribution cooperatives	208,774	181,119	451,091	396,921
Non-members [2]	8,557	6,504	31,336	11,415
Total operating revenues	$ 217,331	$ 187,623	$482,427	$ 408,336
Average cost of energy to member distribution cooperatives (per MWh)	$ 47.40	$ 39.88	$ 44.38	$ 40.46
Average cost of demand to member distribution cooperatives (per MWh)	29.64	28.18	24.98	24.30
Average total cost to member distribution cooperatives (per MWh)	$ 77.04	$ 68.06	$ 69.36	$ 64.76

(1) Includes sales of renewable energy credits of $0.5 million for the three and six months ended June 30, 2014, and immaterial for three and six months ended June 30, 2013, respectively.

(2) Includes sales of renewable energy credits of $3.2 million and $3.7 million for the three and six months ended June 30, 2014, respectively, and $0.8 million and $2.0 million for the three and six months ended June 30, 2013, respectively.

Our energy sales in MWh to our member distribution cooperatives and non-members for the three and six months ended June 30, 2014 and 2013, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
	(in MWh)		(in MWh)	
Energy sales to:				
Member distribution cooperatives	2,709,843	2,661,125	6,503,437	6,128,672
Non-members	125,533	163,434	295,396	266,127
Total energy sales	2,835,376	2,824,559	6,798,833	6,394,799

Our energy sales in MWh to our member distribution cooperatives for the three months ended June 30, 2014, were 1.8% higher as compared to the same period in 2013. For the six months ended June 30, 2014, our energy sales in MWh to our member distribution cooperatives were 6.1% higher, as compared to the same period in 2013. In the first quarter of 2014, the entire mid-Atlantic region experienced extremely cold weather.

Our energy sales in MWh to non-members for the three months ended June 30, 2014, were 23.2% lower, whereas for the six months ended June 30, 2014, they were 11.0% higher, as compared to the same periods in 2013. There was an increase in the volume of excess purchased and generated energy during the first quarter of 2014 as compared to the same period in 2013; however this increase was partially offset by a decrease in the volume of excess purchased and generated energy during the second quarter of 2014 as compared to the same period in 2013.

Total revenues from sales to our member distribution cooperatives for the three and six months ended June 30, 2014, increased $27.7 million, or 15.3%, and $54.2 million, or 13.6%, respectively, as compared to the same periods in 2013, primarily due to net increases in our total energy rate. Our average cost of energy to member distribution cooperatives per MWh increased 18.9% and 9.7%, for the three and six months ended June 30, 2014, respectively, as compared to the same periods in 2013.

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, 2014, was 13.2% and 7.1% higher, respectively, as compared to the same periods in 2013, primarily as a result of net increases in our total energy rate. There was also an increase in demand costs related to purchased capacity and transmission primarily due to increases in charges from PJM as well as increased demand-related operations and maintenance expense related to the scheduled maintenance outages at Clover in 2014 as compared to 2013.

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, 2013	(2.4)
October 1, 2013	4.7
January 1, 2014	0.5
April 1, 2014	11.8

Non-member revenue for the three months ended June 30, 2014, increased $2.1 million, or 31.6%, as compared to the same period in 2013, due to a 319.6% increase in revenue from sales of renewable energy credits. This increase was slightly offset by a 6.8% decrease in revenue from sales of excess energy which was primarily due to a 23.2% decrease in the volume of excess energy sales. Non-member revenue for the six months ended June 30, 2014, increased $19.9 million, or 174.5%, as compared to the same period in 2013, due to a 192.3% increase in revenue from sales of excess energy and a 89.1% increase in revenue from sales of renewable energy credits. The increase in revenue from sales of excess energy was primarily due to a 163.3% increase in the average price of excess energy.

Operating Expenses

The following is a summary of the components of our operating expenses for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
	(in thousands)		**(in thousands)**	
Fuel	$ 29,098	$ 30,317	$ 144,627	$ 61,769
Purchased power	120,797	118,007	310,162	266,659
Deferred energy	16,469	(11,280)	(76,960)	(18,030)
Operations and maintenance	12,137	11,774	26,683	19,860
Administrative and general	11,091	10,655	22,453	21,447
Depreciation and amortization	10,498	10,569	21,004	21,209
Amortization of regulatory asset/(liability), net	965	1,272	2,798	1,584
Accretion of asset retirement obligations	1,019	995	2,038	1,990
Taxes, other than income taxes	2,136	2,184	4,307	4,416
Total Operating Expenses	$ 204,210	$ 174,493	$ 457,112	$ 380,904

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 the fixed portion of operations and maintenance expense, administrative and general, and depreciation and amortization expenses, as well as the capacity portion of our purchased power 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 $29.7 million, or 17.0%, for the three months ended June 30, 2014, as compared to the same period in 2013, primarily due to the increase in deferred energy.

- Deferred energy expense increased $27.7 million for the three months ended June 30, 2014, respectively, as compared to the same period in 2013. For the three months ended June 30, 2014, we over-collected $16.5 million, whereas we under-collected $11.3 million for the same period in 2013. Deferred energy expense represents the difference between energy revenues and energy expenses.

Operating expenses for the six months ended June 30, 2014, were still significantly impacted by the extremely cold weather experienced by the entire mid-Atlantic region during the first quarter of 2014, which increased fuel and purchased power expense, and changed our deferred energy balance from an over-collection to an under-collection. Total operating expenses increased $76.2 million, or 20.0%, for the six months ended June 30, 2014, as compared to the same period in 2013, primarily due to increases in fuel, purchased power, and operations and maintenance expenses, substantially offset by the decrease in deferred energy.

- Fuel expense increased $82.9 million, or 134.1%, for the six months ended June 30, 2014, as compared to the same period in 2013. This increase was primarily driven by the 279.5% increase in the dispatch of our combustion turbine facilities as well as the 213.3% increase in the average cost of fuel for our combustion turbine facilities during the first six months of 2014 as compared to the same period in 2013.

- Purchased power expense, which includes the cost of purchased energy, capacity, and transmission, increased $43.5 million, or 16.3%, for the six months ended June 30, 2014, as compared to the same period in 2013. The average cost of purchased energy increased 13.3% and the volume of purchased energy increased 2.7%.

- Operations and maintenance expense increased $6.8 million, or 34.4%, for the six months ended June 30, 2014, as compared to the same period in 2013, primarily due to the scheduled maintenance outage at Clover.

- Deferred energy expense decreased $58.9 million for the six months ended June 30, 2014, as compared to the same period in 2013. For the six months ended June 30, 2014, we under-collected $77.0 million as compared to the same period in 2013, where we under-collected energy costs by $18.0 million.

Other Items

Investment Income

Investment income decreased for the three months ended June 30, 2014, by $0.3 million, or 17.3%, as compared to the same period in 2013, primarily due to lower income earned on our nuclear decommissioning trust. Investment income increased for the six months ended June 30, 2014, by $1.3 million, or 55.5%, as compared to the same period in 2013, primarily due to higher income earned on our nuclear decommissioning trust.

Interest Charges, Net

The major components of interest charges, net for the three and six months ended June 30, 2014 and 2013, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)		(in thousands)	
Total interest charges	$ (11,647)	$ (11,736)	$ (23,197)	$ (23,663)
Allowance for borrowed funds used during construction	250	51	429	83
Interest charges, net	$ (11,397)	$ (11,685)	$ (22,768)	$ (23,580)

Interest charges, net decreased for the three and six months ended June 30, 2014, by $0.3 million, or 2.5%, and $0.8 million, or 3.4%, respectively, as compared to the same periods in 2013, as a result of the decrease in total interest charges due to scheduled principal payments, and 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, was relatively flat for the three and six months ended June 30, 2014, as compared to the same period in 2013.

Financial Condition

The principal changes in our financial condition from December 31, 2013 to June 30, 2014, were caused by the change in deferred energy, and increases in long-term debt and construction work in progress, slightly offset by the decrease in unrestricted investments and other.

- Deferred energy changed $77.0 million as a result of the under-collection of our energy costs in 2014. The deferred energy balance changed from a $37.2 million liability (over-collection) at December 31, 2013 to a $39.8 million asset (under-collection) at June 30, 2014.

- Long-term debt increased $57.0 million due to outstanding borrowings under our revolving credit facility.

- Construction work in progress increased $52.0 million primarily due to expenditures related to Wildcat Point and nuclear fuel.

- Unrestricted investment and other decreased $18.3 million primarily as a result of the liquidation of temporary investments.

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 2014, our operating activities used cash flows of $48.9 million and during the first six months of 2013, our operating activities provided cash flows of $15.3 million. Operating activities in 2014 were primarily impacted by the following:

- Deferred energy changed $77.0 million due to the under-collection of energy costs in 2014. To address our under-collected deferred energy balance, we increased our total energy rate 11.8% effective April 1, 2014.

Revolving Credit Facility

We currently maintain a $500.0 million, five-year revolving credit facility to cover our short-term and medium-term funding needs. Commitments under this syndicated credit agreement extend until March 5, 2019, unless earlier terminated in accordance with the agreement. At June 30, 2014, we had $57.0 million in borrowings outstanding under this facility, which are recorded in long-term debt. Additionally, at June 30, 2014, we had a letter of credit in the amount of $7.0 million outstanding. At December 31, 2013, we did not have any borrowings or letters of credit outstanding under this facility.

Financings

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

Uses

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

Contractual Obligations

In the normal course of business, we enter into long-term arrangements relating to the construction, operation and maintenance of our generating facilities, power purchases for capacity and energy, the financing of our operations, and other matters. On April 8, 2014, we received a Final Order granting approval of the Wildcat Point CPCN from the MPSC and on June 2, 2014, we selected White Oak Power Constructors as the EPC contractor. As a result of these events, we have had a change to our contractual obligations, specifically with respect to construction obligations as follows:

	Payments due by Period				
	Total	2014	2015-2016	2017-2018	2019 and Thereafter
			(in millions)		
Long-term indebtedness	$ 1,399.0	$ 71.0	$ 137.0	$ 130.4	$ 1,060.6
Power purchase obligations	1,191.5	212.0	387.6	332.1	259.8
Asset retirement obligations	389.4	-	-	-	389.4
Operating lease obligations	112.2	0.5	1.0	1.5	109.2
Construction obligations	575.7	92.4	464.2	19.1	-
Total	$ 3,667.8	$ 375.9	$ 989.8	$ 483.1	$ 1,819.0

See "Liquidity and Capital Resources—Contractual Obligations" in Item 7 of our 2013 Annual Report on Form 10-K. We expect to fund these obligations with cash flow from operations, borrowings under our syndicated credit facility, and financings in the debt capital markets.

Long-term Indebtedness

At December 31, 2013, all of our long-term indebtedness was issued under the Indenture and includes bonds issued privately and to the public. Long-term indebtedness includes both the principal of and interest on long-term indebtedness, long-term indebtedness due within one year and unamortized discounts and premiums relating to long-term indebtedness.

Power Purchase Obligations

As part of our power supply strategy, we entered into a number of agreements for the purchase of capacity or energy, or both, in order to meet our member distribution cooperatives' requirements.

Asset Retirement Obligations

We account for our asset retirement obligations in accordance with Accounting for Asset Retirement and Environmental Obligations which requires legal obligations associated with the retirement of long-lived assets to be recognized at fair value when incurred and capitalized as part of the related long-lived asset. A significant portion of our asset retirement obligations relates to the future decommissioning of North Anna by 2059.

Operating Lease Obligations

Our obligation described above primarily relates to our portion of the Clover Unit 1 purchase option price at the end of the term of the leaseback that will be satisfied by our investment in United States Treasury securities.

Construction Obligations

This includes payments related to major equipment purchase contracts for Wildcat Point as well as EPC contractor payments. Wildcat Point will consist of two combustion turbines, two heat recovery steam generators, and one steam turbine generator. Mitsubishi will supply the combustion turbines and Alstom will supply the heat recovery steam generators and the steam turbine generator.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the second quarter of 2014.

ITEM 4. CONTROLS AND PROCEDURES

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

FERC Proceeding Related to Formula Rate

On September 30, 2013, we filed with FERC to revise our cost-based formula rate 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. Settlement discussions have been terminated and a litigation schedule has been set with a hearing date of December 9, 2014. The Presiding Judge has referred the parties to dispute resolution procedures with the assistance of FERC Dispute Resolution Service. Discussions are ongoing, parallel with the hearing procedures.

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 2013 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. The results of our efforts cannot currently be determined.

Clean Power Plan

On June 2, 2014, the EPA proposed emission guidelines for CO_2 from existing electric utility generating units under 111(d) of the Clean Air Act. This proposal, referred to as the Clean Power Plan, requires that each state develop, submit, and implement a plan to achieve the interim and final state-specific goals detailed in the rulemaking. The EPA proposal has defined the following four areas of focus which the states are to utilize to meet the proposed goals:

- increase efficiency of existing fossil-fuel plants;
- increase dispatch of existing natural gas combined-cycle units;
- utilize and expand the use of zero-emitting generation (additional renewables and nuclear); and
- increase demand-side energy efficiency.

Public hearings on the Clean Power Plan were held by the EPA on July 29 – August 1, 2014. We continue to follow developments related to the guidelines, including state regulatory developments. Due to the general nature of the guidelines and the lack of specifics regarding state implementation, we cannot predict whether the final rules relating to the guidelines will have a material impact on our results of operations or financial condition.

CSAPR

The EPA proposed CSAPR, also known as the "Transport Rule," that would require 27 states and the District of Columbia to significantly improve air quality by reducing power plant SO_2 and NO_x emissions that contribute to ozone and fine particle pollution in other states. Emissions reductions were originally scheduled to take effect in 2012. However, on December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued a stay to the implementation of CSAPR pending judicial review. On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, ruling that the EPA had exceeded its statutory authority. On October 5, 2012, the EPA petitioned for a rehearing of the U.S. Court of Appeals for the District of Columbia Circuit CSAPR decision. On January 24, 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied the EPA's petition for rehearing. On June 24, 2013, the U.S. Supreme Court granted the United States' petition asking the U.S. Supreme Court to review the U.S. Court of Appeals for the District of Columbia Circuit decision on CSAPR and heard arguments on the matter in December 2013. On April 29, 2014, the U.S. Supreme Court overturned the U.S. Court of Appeals for the District of Columbia Circuit's 2012 ruling and reinstated CSAPR. As this matter continues through the judicial process, CAIR remains in effect. We continue to follow developments related to CSAPR and we currently cannot predict the impact this matter will have on our results of operations or financial condition.

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

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 8, 2014

/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 8, 2014

/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 8, 2014

/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, 2014 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 8, 2014

/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, 2014 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 8, 2014

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