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, 2018

or

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

For the transition period from _________ to _________

Commission file number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE
(Exact name of registrant as specified in its charter)

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

(804) 747-0592
(Registrant's telephone number, including area code)

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☐ No ☒

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

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

Larger accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	Smaller reporting company	☐
Emerging growth company	☐		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

The Registrant is a membership corporation and has no authorized or outstanding equity securities.

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
ACES	Alliance for Cooperative Energy Services Power Marketing, LLC
Alstom	Alstom Power, Inc.
Bear Island	Bear Island Paper WB LLC
Clover	Clover Power Station
EPRS	Essential Power Rock Springs, LLC
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.
MW	Megawatt(s)
MWh	Megawatt hour(s)
North Anna	North Anna Nuclear Power Station
North Anna Unit 3	A potential additional nuclear-powered generating unit at North Anna
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
REC	Rappahannock Electric Cooperative
RTO	Regional transmission organization
TEC	TEC Trading, Inc.
Virginia Power	Virginia Electric and Power Company
Wildcat Point	Wildcat Point Generation Facility
WOPC	White Oak Power Constructors
XBRL	Extensible Business Reporting Language

OLD DOMINION ELECTRIC COOPERATIVE

INDEX

OLD DOMINION ELECTRIC COOPERATIVE

PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2018	December 31, 2017
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	$ 2,451,132	$ 1,754,236
Less accumulated depreciation	(842,656)	(891,701)
Net Property, plant, and equipment	1,608,476	862,535
Nuclear fuel, at amortized cost	20,999	18,089
Construction work in progress	30,850	822,667
Net Electric Plant	1,660,325	1,703,291
Investments:		
Nuclear decommissioning trust	183,901	183,681
Lease deposits	64,894	106,812
Unrestricted investments and other	7,395	7,009
Total Investments	256,190	297,502
Current Assets:		
Cash and cash equivalents	1,445	4,084
Restricted cash and cash equivalents	14,200	—
Accounts receivable	11,430	10,379
Accounts receivable–members	80,788	83,133
Fuel, materials, and supplies	51,607	52,766
Deferred energy	39,237	3,669
Prepayments and other	4,416	5,274
Assets held for sale	72,462	—
Total Current Assets	275,585	159,305
Deferred Charges:		
Regulatory assets	40,646	45,284
Other	3,025	3,780
Total Deferred Charges	43,671	49,064
Total Assets	$ 2,235,771	$ 2,209,162
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 421,966	$ 415,384
Non-controlling interest	5,755	5,744
Total Patronage capital and Non-controlling interest	427,721	421,128
Long-term debt	1,198,663	1,198,396
Revolving credit facility	96,100	43,400
Total Long-term debt and Revolving credit facility	1,294,763	1,241,796
Total Capitalization	1,722,484	1,662,924
Current Liabilities:		
Long-term debt due within one year	40,792	40,792
Accounts payable	110,519	92,259
Accounts payable–members	53,698	59,064
Accrued expenses	8,975	6,391
Regulatory liability–revenue deferral	7,500	15,000
Obligations under long-term lease	63,807	103,683
Total Current Liabilities	285,291	317,189
Deferred Credits and Other Liabilities:		
Asset retirement obligations	128,024	126,470
Regulatory liabilities	99,453	101,237
Other	519	1,342
Total Deferred Credits and Other Liabilities	227,996	229,049
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$ 2,235,771	$ 2,209,162

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,	
	2018	**2017**	**2018**	**2017**
	(in thousands)			
Operating Revenues	$ 226,652	$ 156,907	$454,661	$346,686
Operating Expenses:				
Fuel	49,523	20,498	82,439	38,181
Purchased power	61,441	80,729	228,586	202,845
Transmission	32,083	23,979	65,229	47,721
Deferred energy	16,704	(4,705)	(35,568)	(26,243)
Operations and maintenance	19,599	12,099	33,000	24,572
Administrative and general	11,653	11,309	23,255	22,439
Depreciation and amortization	17,083	11,340	28,761	22,683
Amortization of regulatory asset/liability, net	(1,838)	(850)	(4,641)	(20)
Accretion of asset retirement obligations	1,331	1,257	2,661	2,512
Taxes, other than income taxes	2,581	2,087	4,718	4,191
Total Operating Expenses	210,160	157,743	428,440	338,881
Operating Margin	16,492	(836)	26,221	7,805
Other expense, net	(1,056)	(955)	(2,273)	(1,904)
Investment income	2,760	6,748	4,521	8,269
Interest income on North Anna Unit 3 cost recovery	57	4,427	141	4,427
Interest charges, net	(14,922)	(6,327)	(22,012)	(12,571)
Income taxes	(3)	(2)	(4)	(2)
Net Margin including Non-controlling interest	3,328	3,055	6,594	6,024
Non-controlling interest	(9)	(8)	(12)	(9)
Net Margin attributable to ODEC	3,319	3,047	6,582	6,015
Patronage Capital - Beginning of Period	418,647	405,825	415,384	402,857
Patronage Capital - End of Period	$ 421,966	$ 408,872	$421,966	$408,872

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, 2018	Six Months Ended June 30, 2017
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	$ 6,594	$ 6,024
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	28,761	22,683
Other non-cash charges	9,182	9,625
Amortization of lease obligations	3,424	3,374
Interest on lease deposits	(1,314)	(1,511)
Change in current assets	2,538	(838)
Change in deferred energy	(35,568)	(26,243)
Change in current liabilities	(4,856)	(12,592)
Change in regulatory assets and liabilities	(521)	2,800
Change in deferred charges-other and deferred credits and other liabilities-other	(923)	1,301
Net Cash Provided by Operating Activities	7,317	4,623
Investing Activities:		
Purchases of held to maturity securities	(310)	(2,523)
Proceeds from sale of held to maturity securities	43,301	2,824
Increase in other investments	(4,487)	(8,193)
Electric plant additions	(43,405)	(86,080)
Net Cash Used for Investing Activities	(4,901)	(93,972)
Financing Activities:		
Debt issuance costs	(255)	—
Payment of obligation under long-term lease	(43,300)	—
Draws on revolving credit facility	289,300	303,250
Repayments on revolving credit facility	(236,600)	(215,700)
Net Cash Provided by Financing Activities	9,145	87,550
Net Change in Cash and Cash Equivalents and Restricted Cash and Cash Equivalents	11,561	(1,799)
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - Beginning of Period	4,084	2,946
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - End of Period	$ 15,645	$ 1,147

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, 2018, our consolidated results of operations for the three and six months ended June 30, 2018 and 2017, and cash flows for the six months ended June 30, 2018 and 2017. The consolidated results of operations for the three and six months ended June 30, 2018, 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 2017 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 eleven Class A members are 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 \$5.8 million as of June 30, 2018, and \$5.7 million as of December 31, 2017. 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 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 condensed 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, 2018 and December 31, 2017:

	June 30, 2018	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]	$ 58,524	$ 58,524	$ —	$ —
Nuclear decommissioning trust - net asset value [1][2]	125,377	—	—	—
Unrestricted investments and other [3]	406	—	406	—
Derivatives - gas and power [4]	668	—	668	—
Total Financial Assets	$ 184,975	$ 58,524	$ 1,074	$ —
Derivatives - gas and power [4]	$ 113	$ 113	$ —	$ —
Total Financial Liabilities	$ 113	$ 113	$ —	$ —

	December 31, 2017	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]	$ 59,723	$ 59,723	$ —	$ —
Nuclear decommissioning trust - net asset value [1][2]	123,958	—	—	—
Unrestricted investments and other [3]	308	—	308	—
Total Financial Assets	$ 183,989	$ 59,723	$ 308	$ —
Derivatives - gas and power [4]	$ 1,034	$ 975	$ 59	$ —
Total Financial Liabilities	$ 1,034	$ 975	$ 59	$ —

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

(2) Nuclear decommissioning trust includes investments measured at net asset value per share (or its equivalent) as a practical expedient and these investments have not been categorized in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the Condensed Consolidated Balance Sheet.

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

(4) Derivatives - gas and power represent natural gas futures contracts. Level 1 are indexed against NYMEX. Level 2 are valued by ACES using observable market inputs for similar transactions. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2017 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 2017 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.

Outstanding derivative instruments, excluding contracts accounted for as normal purchase/normal sale, were as follows:

		Quantity	
Commodity	Unit of Measure	As of June 30, 2018	As of December 31, 2017
Natural gas	MMBTU	21,660,000	23,700,000

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, 2018	As of December 31, 2017
		(in thousands)	
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges-other	$ 668	$ —
Total derivatives in an asset position		$ 668	$ —
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 113	$ 1,034
Total derivatives in a liability position		$ 113	$ 1,034

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, 2018 and 2017

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,	
	2018	2017		2018	2017	2018	2017
	(in thousands)			(in thousands)			
Natural gas futures contracts	$ 742	$ 656	Fuel	$ (215)	$ 1,130	$ (1,110)	$ 999
Total	$ 742	$ 656		$ (215)	$ 1,130	$ (1,110)	$ 999

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

4. *Investments*

Investments were as follows as of June 30, 2018 and December 31, 2017:

Description	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
			(in thousands)		
June 30, 2018					
Nuclear decommissioning trust [1]					
Debt securities	$ 55,154	$ 3,143	$ —	$ 58,297	$ 58,297
Equity securities	81,496	45,161	(1,280)	125,377	125,377
Cash and other	227	—	—	227	227
Total Nuclear Decommissioning Trust	$ 136,877	$ 48,304	$ (1,280)	$ 183,901	$ 183,901
Lease Deposits [2]					
Government obligations	$ 64,894	$ 171	$ —	$ 65,065	$ 64,894
Total Lease Deposits	$ 64,894	$ 171	$ —	$ 65,065	$ 64,894
Unrestricted investments					
Government obligations	$ 2,348	$ —	$ (7)	$ 2,341	$ 2,348
Debt securities	2,457	—	(6)	2,451	2,457
Total Unrestricted Investments	$ 4,805	$ —	$ (13)	$ 4,792	$ 4,805
Other					
Equity securities	$ 318	$ 88	$ —	$ 406	$ 406
Non-marketable equity investments	2,184	2,132	—	4,316	2,184
Total Other	$ 2,502	$ 2,220	$ —	$ 4,722	$ 2,590
					$ 256,190
December 31, 2017					
Nuclear decommissioning trust [1]					
Debt securities	$ 54,375	$ 5,029	$ —	$ 59,404	$ 59,404
Equity securities	77,838	46,474	(354)	123,958	123,958
Cash and other	319	—	—	319	319
Total Nuclear Decommissioning Trust	$ 132,532	$ 51,503	$ (354)	$ 183,681	$ 183,681
Lease Deposits [2]					
Government obligations	$ 106,812	$ 776	$ —	$ 107,588	$ 106,812
Total Lease Deposits	$ 106,812	$ 776	$ —	$ 107,588	$ 106,812
Unrestricted investments					
Government obligations	$ 2,344	$ —	$ (13)	$ 2,331	$ 2,344
Debt securities	2,217	—	(3)	2,214	2,217
Total Unrestricted Investments	$ 4,561	$ —	$ (16)	$ 4,545	$ 4,561
Other					
Equity securities	$ 223	$ 85	$ —	$ 308	$ 308
Non-marketable equity investments	2,140	2,066	—	4,206	2,140
Total Other	$ 2,363	$ 2,151	$ —	$ 4,514	$ 2,448
					$ 297,502

(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 2017 Annual Report on Form 10-K. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or regulatory asset, respectively.

(2) Investments in lease deposits are restricted for the use of funding our future lease obligations. See Note 8 of the Notes to Consolidated Financial Statements in our 2017 Annual Report on Form 10-K.

Contractual maturities of debt securities as of June 30, 2018, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Other [1]	$ —	$ —	$ 58,297	$ —	$ 58,297
Held to maturity	69,459	240	—	—	69,699
Total	$ 69,459	$ 240	$ 58,297	$ —	$ 127,996

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

5. Other

Wildcat Point Generation Facility

On April 17, 2018, Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, achieved commercial operation and was available for dispatch by PJM.

The facility originally was scheduled to become operational in mid-2017. WOPC, a joint venture between PCL Industrial Construction Company and Sargent & Lundy, L.L.C., as the EPC contractor, claims the delay was associated with the incurrence of additional work and other matters, including alleged misrepresentation in the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. On May 24, 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. An amended complaint was filed on July 21, 2017. On August 21, 2017, motions were filed by Alstom and us to transfer venue from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia and on November 7, 2017, these motions were granted. We have reviewed the asserted claims of WOPC against us and believe they are without merit. We have not recorded any liability related to these claims as we do not believe any liability is estimable or probable. We intend to vigorously defend against these claims.

Additionally, on September 29, 2017, we filed a complaint in the United States District Court for the Eastern District of Virginia against WOPC, alleging that WOPC breached the EPC contract. On November 16, 2017, the United States District Court for the Eastern District of Virginia ordered that the WOPC complaint against Alstom and us, our complaint against WOPC, and a separate complaint filed by WOPC against Mitsubishi on May 9, 2017, be consolidated into one case. On June 27, 2018, an order was issued establishing January 9, 2019 as the date to check the status of discovery, set summary judgement deadlines, and set a trial date.

If it is ultimately determined that we owe any such amounts to WOPC, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates to our member distribution cooperatives.

Through June 30, 2018, we capitalized construction costs related to Wildcat Point totaling $842.4 million, which includes $88.4 million of capitalized interest and is offset by $53.2 million of liquidated damages.

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. On April 13, 2015, we received an initial decision from the hearing judge. On January 19, 2017, FERC issued its order on the hearing judge's initial decision. On February 21, 2017, we submitted our compliance filing, revising the formula rate as we previously suggested and FERC directed in the January 19, 2017 order. Additionally, on February 21, 2017, Bear Island filed a request for rehearing. On March 22, 2017, FERC issued an order granting rehearing of its initial order for the limited purpose of FERC's further consideration of the matter. On March 22, 2018, FERC issued an order denying Bear Island's request for rehearing and accepted our February 21, 2017 compliance filing that revised the formula rate as directed by FERC's January 19, 2017 order. We filed a refund report with FERC on April 23, 2018, that calculated the difference between rates charged under our rate schedule since January 1, 2014, and rates that would have been charged under the revised rate schedule submitted in our February 21, 2017 compliance filing. On July 24, 2018, FERC accepted the refund report, which will result in a reallocation of costs among our member distribution cooperatives and will not result in any change to our total operating revenues.

Revolving Credit Facility

We maintain a revolving credit facility to cover our short-term and medium-term funding needs that are not met by cash from operations or other available funds. Commitments under this syndicated credit agreement extend until March 3, 2023. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through March 3, 2023. As of June 30, 2018, we had outstanding under this facility, $96.1 million in borrowings and $2.5 million in letters of credit. As of December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings and $12.0 million in letters of credit.

Limited Exception under Wholesale Power Contracts

We have a wholesale power contract with each of our member distribution cooperatives. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions. One of the limited exceptions permits each of our member distribution cooperatives, with 180 days prior written notice, to receive up to the greater of 5% of its demand and associated energy or 5 MW and associated energy from its owned generation or from other suppliers. If all of our member distribution cooperatives elected to utilize the 5% or 5 MW exception, we estimate the current impact would be a reduction of approximately 175 MW of demand and associated energy. As of May 1, 2018, there are approximately 66 MW remaining that can be utilized under this exception. The following table summarizes the cumulative removal of load requirements under this exception since January 1, 2016.

Date	**MW**
January 1, 2016	9
May 1, 2016	60
June 1, 2017	65
May 1, 2018	109

We do not anticipate that either the current or potential full utilization of this exception will have a material impact on our financial condition, results of operations, or cash flows.

Cash and Cash Equivalents

The following table provides a reconciliation of cash and cash equivalents and restricted cash and cash equivalents reported within the Condensed Consolidated Balance Sheet that sum to the total of the same amounts shown in the Condensed Consolidated Statement of Cash Flows:

	As of June 30,	
	2018	**2017**
	(in thousands)	
Cash and cash equivalents	$ 1,445	$ 1,147
Restricted cash and cash equivalents	14,200	—
	$ 15,645	$ 1,147

Restricted cash and cash equivalents relates to funds held in escrow for payments to Mitsubishi for Wildcat Point.

Sale of Rock Springs Combustion Turbine Facility

We and EPRS each individually own two natural gas-fired combustion turbine units and a 50% undivided interest in related common facilities at Rock Springs. On June 14, 2018, we entered into an asset purchase agreement for EPRS' purchase of our interest in Rock Springs and related assets. As of June 30, 2018, we have reclassified the Rock Springs assets to assets held for sale on our Condensed Consolidated Balance Sheet. Consideration for the purchase is $115 million and the assumption of certain related liabilities (not including indebtedness) associated with the acquired assets. The agreement contains customary representations, warranties, covenants, and termination rights of the parties. Closing of the transaction is subject to a number of conditions, including: obtainment of required consents or approvals from governmental authorities and approval by FERC; EPRS' obtainment of financing for the acquisition; and other customary closing conditions. We currently anticipate that the transaction will close in 2018 and will result in a gain of approximately $40 million that we plan to defer as a regulatory liability.

New Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update 2014-09 Revenue from Contracts with Customers (Topic 606). This update requires entities to recognize revenue when the transfer of promised goods or services to customers occurs in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. We supply power requirements (energy and demand) to our eleven member distribution cooperatives subject to substantially identical wholesale power contracts with each of them. The revenues from these wholesale power contracts constituted at least 95% of our total revenues for the past three years. We bill our member distribution cooperatives monthly and each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract. We transfer control of the electricity over time and our member distribution cooperatives simultaneously receive and consume the benefits of the electricity. The amount we invoice our member distribution cooperatives on a monthly basis corresponds directly to the value to the member distribution cooperatives of our performance, which is determined by our formula rate included in the wholesale power contract. We also sell excess energy and renewable energy credits to non-members at prevailing market prices as control is transferred. We have completed our contract review of our wholesale power and other contracts within the scope of Topic 606, and have finalized our analysis. We have not identified any material impact to our recognition of revenue from the sale of power to our member distribution cooperatives or non-members. We adopted this standard effective January 1, 2018, using the modified retrospective approach. There was no material impact to our recognition of revenue from the sale of power to our member distribution cooperatives or non-members, and there has been no cumulative effect adjustment recognized.

Our operating revenues for the three and six months ended June 30, 2018, were as follows:

	Three Months Ended June 30, 2018	Six Months Ended June 30, 2018
	(in thousands)	
Member distribution cooperatives		
Sales to member distribution cooperatives, excluding renewable energy credit sales	$ 202,822	$ 427,113
Renewable energy credit sales to member distribution cooperatives	1	12
Total sales to member distribution cooperatives	$ 202,823	$ 427,125
Non-members		
Sales to non-members, excluding renewable energy credit sales	$ 23,829	$ 26,971
Renewable energy credit sales to non-members	—	565
Total sales to non-members	$ 23,829	$ 27,536
Total operating revenues	$ 226,652	$ 454,661

In January 2016, the FASB issued Accounting Standards Update 2016-01 Recognition and Measurement of Financial Assets and Financial Liabilities. This update retained the current framework for accounting for financial instruments in GAAP but made targeted improvements to address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. We adopted this update during the current period. The update requires us to measure equity investments at fair value and recognize any changes in fair value in net margin. We account for certain revenues and expenses as a rate-regulated entity in accordance with Accounting for Regulated Operations. With approval from our board of directors, changes in fair value of certain equity investments are recognized as a change in our regulatory liability account on our condensed consolidated balance sheet. See Note 4—Investments above.

In February 2016, the FASB issued Accounting Standards Update 2016-02 Leases (Subtopic 835-30). This update revised accounting guidance for the recognition, measurement, presentation and disclosure of leasing arrangements. The update requires the recognition of lease assets and liabilities for those leases currently classified as operating leases while also refining the definition of a lease. In addition, lessees will be required to disclose key information about the amount, timing, and uncertainty of cash flows arising from leasing arrangements. We are currently evaluating the impact of this pronouncement and whether we will elect to adopt certain practical expedients that are provided for under the new standard. We plan to adopt this standard for the fiscal year beginning January 1, 2019.

In November 2016, the FASB issued Accounting Standards Update 2016-18 Statement of Cash Flows (Topic 230): Restricted Cash. This update revised accounting guidance for the classification and presentation of restricted cash in the statement of cash flows. We adopted this update effective January 1, 2018, and it requires a reconciliation of cash and cash equivalents and restricted cash and cash equivalents within the Condensed Consolidated Balance Sheet and the amounts shown in the Condensed Consolidated Statement of Cash Flows. See "Cash and Cash Equivalents" above.

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, 2018, there have been no significant changes in our critical accounting policies as disclosed in our 2017 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, 2018, were primarily impacted by the commercial operation of Wildcat Point, and weather that resulted in increases in our member distribution cooperatives' requirements for power and the dispatch of our generating facilities. Additionally, we increased our total energy rate 11.1%, effective January 1, 2018, and 3.7%, effective April 1, 2018, to address our under-collected costs.

- Wildcat Point, which achieved commercial operation and was available for dispatch by PJM on April 17, 2018, generated over 950,000 MWh in the second quarter of 2018, resulting in increased fuel expense. Once commercial operation was achieved, we began recognizing expenses related to operations and maintenance, administrative and general, depreciation, and interest charges.

- Generation from our combustion turbine facilities increased 176.7% and 210.5%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017, due to PJM's economic dispatch of these facilities, which resulted in increased fuel expense.

- Due to the increased generation from our owned generating facilities, our non-member sales increased and our purchased power costs decreased for the three months ended June 30, 2018, as compared to the same period in 2017.

- Our energy revenues from sales to our member distribution cooperatives increased $17.2 million, or 19.4%, and $47.0 million, or 23.8%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017. The average cost of energy sold to our member distribution cooperatives increased 15.3% and 12.9%, respectively, for the three and six months ended June 30, 2018, due to the energy rate increases implemented in 2018. Also, energy sales in MWh to our member distribution cooperatives increased 3.6% and 9.7%, respectively. Absent the impact of the removal of load under the limited exception under wholesale power contracts as described below, beginning May 1, 2018, our energy sales in MWh would have increased 6.0% and 10.8%, respectively.

- As a result of higher costs, we under-collected energy costs by $52.3 million in the first quarter of 2018. As of March 31, 2018, our deferred energy balance was $55.9 million under-collected. To address the under-collection, we increased our total energy rate 3.7% effective April 1, 2018. As of June 30, 2018, our deferred energy balance was $39.2 million under-collected.

Also, on June 14, 2018, we entered into an asset purchase agreement for EPRS' purchase of our interest in Rock Springs and related assets. See "Factors Affecting Results—Generating Facilities—Sale of Rock Springs Combustion Turbine Facility."

Wildcat Point Generation Facility

On April 17, 2018, Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, achieved commercial operation and was available for dispatch by PJM.

The facility originally was scheduled to become operational in mid-2017. WOPC, the EPC contractor, claims the delay was associated with the incurrence of additional work and other matters, including alleged misrepresentation under the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. See "Wildcat Point" in "Legal Proceedings" in Part II, Item 1. If it is ultimately determined that we owe any such amounts to WOPC, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates to our member distribution cooperatives.

Through June 30, 2018, we capitalized construction costs related to Wildcat Point totaling $842.4 million, which includes $88.4 million of capitalized interest and is offset by $53.2 million of liquidated damages.

Limited Exception under Wholesale Power Contracts

We have a wholesale power contract with each of our member distribution cooperatives. Each contract obligates us to sell and deliver to the member distribution cooperative, and obligates the member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions. One of the limited exceptions permits each of our member distribution cooperatives, with 180 days prior written notice, to receive up to the greater of 5% of its demand and associated energy or 5 MW and associated energy from its owned generation or from other suppliers. If all of our member distribution cooperatives elected to utilize the 5% or 5 MW exception, we estimate the current impact would be a reduction of approximately 175 MW of demand and associated energy. As of May 1, 2018, there are approximately 66 MW remaining that can be utilized under this exception. The following table summarizes the cumulative removal of load requirements under this exception since January 1, 2016.

Date	MW
January 1, 2016	9
May 1, 2016	60
June 1, 2017	65
May 1, 2018	109

We do not anticipate that either the current or potential full utilization of this exception by our member distribution cooperatives will have a material impact on our financial condition, results of operations, or cash flows. For further discussion of Wholesale Power Contracts, see "Business—Members—Member Distribution Cooperatives—Wholesale Power Contracts" in Item 1 of our 2017 Annual Report on Form 10-K.

Factors Affecting Results

Formula Rate

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

The rates we charge our member distribution cooperatives for sales of energy and demand are determined by a formula rate accepted by FERC. On December 2, 2013, FERC accepted our formula rate effective January 1, 2014, subject to refund, and established hearing and settlement procedures. On January 19, 2017, FERC directed us to submit a compliance filing making certain revisions to the formula rate. These revisions to the formula rate did not change our overall revenue requirements. On March 22, 2018, FERC accepted our compliance filing and required us to file a refund report to calculate the difference between rates charged under our rate schedule since January 1, 2014, and rates that would have been charged under the revised rate schedule submitted in our compliance filing. On July 24, 2018, FERC accepted the refund report, which will result in a reallocation of costs among our member distribution cooperatives and will not result in any change to our operating revenues. See "FERC Proceeding Related to Formula Rate" in "Legal Proceedings" in Part II, Item 1.

Our formula rate 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 (collectively referred to as the total energy rate). The base energy rate is developed annually to collect energy costs as estimated in our budget including amounts in the deferred energy account from the prior year. As of January 1 of each year, the base energy rate is reset in accordance with our budget and the energy adjustment rate is reset to zero. We can revise the energy adjustment rate during the year if it becomes apparent that the total energy rate is over-collecting or under-collecting our actual and anticipated energy costs. Any revision to the energy adjustment rate requires board approval and that the resulting change to the total energy rate is at least 2%.

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. We collect our total demand costs through the following three separate rates:

- transmission service rate – designed to collect transmission-related and distribution-related costs;
- RTO capacity service rate – designed to collect capacity costs in PJM that PJM allocates to ODEC and all other PJM members; and
- remaining owned capacity service rate – designed to collect 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. The formula rate permits us to adjust revenues from the member distribution cooperatives to equal our actual total 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. We make these adjustments utilizing Margin Stabilization.

We may revise our budget at any time to the extent that our current budget does not accurately reflect our costs and expenses or estimates of our sales of power. Increases or decreases in our budget automatically amend the energy and/or the demand components of our formula rate, as necessary. If at any time our board of directors determines that the formula does not meet all of our costs and expenses, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval.

As detailed in the table below, we increased revenues utilizing Margin Stabilization for the three months ended June 30, 2018. We reduced revenues utilizing Margin Stabilization for the three months ended June 30, 2017, and for the six months ended June 30, 2018 and 2017.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	**2017**	**2018**	**2017**
	(in thousands)			
Margin Stabilization adjustment	$(4,576)	$18,988	$15,071	$37,022

For further discussion of Margin Stabilization, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Margin Stabilization” in Item 7 of our 2017 Annual Report on Form 10-K.

On November 7, 2017, our board of directors approved an additional equity contribution of $14.1 million and declared a patronage capital retirement of $14.1 million which was paid on April 2, 2018.

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 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, 2018, were as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Heating degree days	119	5	2,280.0%	1,993	1,637	21.7%
Cooling degree days	434	285	52.3	434	285	52.3

Power Supply Resources

We provide power to our members through a combination of our interests in Wildcat Point, a combined cycle generation facility; Clover, a coal-fired generation facility; North Anna, a nuclear power station; our three combustion turbine facilities – Louisa, Marsh Run, and Rock Springs; diesel-fired 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, 2018 and 2017, were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2018		**2017**		**2018**		**2017**	
	(in MWh and percentages)							
Generated:								
Wildcat Point	954,748	29.7%	—	—%	954,748	14.1%	—	—%
Clover	310,549	9.7	405,759	15.9	762,643	11.3	758,830	13.3
North Anna	444,982	13.8	490,585	19.3	875,521	12.9	976,642	17.2
Louisa	156,001	4.9	65,201	2.6	247,467	3.7	90,129	1.6
Marsh Run	219,362	6.8	54,974	2.1	359,259	5.3	87,186	1.5
Rock Springs	85,216	2.7	46,286	1.8	87,543	1.3	46,286	0.8
Distributed Generation	132	—	162	—	608	—	188	—
Total Generated	2,170,990	67.6	1,062,967	41.7	3,287,789	48.6	1,959,261	34.4
Purchased:								
Other than renewable:								
Long-term and short-term	528,367	16.5	975,621	38.3	1,939,036	28.7	2,612,270	45.9
Spot market	328,845	10.2	325,369	12.8	1,095,617	16.2	685,699	12.1
Total Other than renewable	857,212	26.7	1,300,990	51.1	3,034,653	44.9	3,297,969	58.0
Renewable [(1)]	184,575	5.7	182,907	7.2	436,334	6.5	432,071	7.6
Total Purchased	1,041,787	32.4	1,483,897	58.3	3,470,987	51.4	3,730,040	65.6
Total Available Energy	3,212,777	100.0%	2,546,864	100.0%	6,758,776	100.0%	5,689,301	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 generating facilities, which are under dispatch control of PJM. For further discussion of PJM, see “Business—Power Supply Resources—PJM” in Item 1 of our 2017 Annual Report on Form 10-K.

Operational Availability

The operational availability of our owned generating resources for the three and six months ended June 30, 2018 and 2017, was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Wildcat Point [(1)]	81.8%	—%	81.8%	—%
Clover	56.0	67.9	74.8	71.7
North Anna	91.7	100.0	90.0	99.6
Louisa	90.9	91.0	95.2	95.4
Marsh Run	89.8	99.5	94.4	99.5
Rock Springs	91.3	98.6	88.0	94.9

(1) Wildcat Point achieved commercial operation on April 17, 2018, and was off-line from May 11, 2018 to May 28, 2018, for a scheduled outage.

Capacity Factor

The output of Wildcat Point, Clover, and North Anna for the three and six months ended June 30, 2018 and 2017, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Wildcat Point [(1)]	59.5%	—%	59.5%	—%
Clover	33.5	43.7	41.3	41.2
North Anna	92.9	102.4	91.9	102.5

(1) Wildcat Point achieved commercial operation on April 17, 2018, and was off-line from May 11, 2018 to May 28, 2018, for a scheduled outage.

Outages

The scheduled and unscheduled outages for Clover and North Anna for the three and six months ended June 30, 2018 and 2017, 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,	
	2018	2017	2018	2017	2018	2017	2018	2017
	(in days)				(in days)			
Scheduled	64.7	49.6	64.7	77.5	15.2	—	36.2	—
Unscheduled	15.4	8.8	26.5	24.7	—	—	—	1.4
Total	80.1	58.4	91.2	102.2	15.2	—	36.2	1.4

The outage days above for Clover and North Anna reflect the total number of outage days for the two units at Clover and the two units at North Anna.

Sale of Rock Springs Combustion Turbine Facility

We and EPRS each individually own two natural gas-fired combustion turbine units and a 50% undivided interest in related common facilities at Rock Springs. On June 14, 2018, we entered into an asset purchase agreement for EPRS' purchase of our interest in Rock Springs and related assets. As of June 30, 2018, we have reclassified the Rock Springs assets to assets held for sale on our Condensed Consolidated Balance Sheet. Consideration for the purchase is $115 million and the assumption of certain related liabilities (not including indebtedness) associated with the acquired assets. The agreement contains customary representations, warranties, covenants, and termination rights of the parties. Closing of the transaction is subject to a number of conditions, including: obtainment of required consents or approvals from governmental authorities and approval by FERC; EPRS' obtainment of financing for the acquisition; and other customary closing conditions. We currently anticipate that the transaction will close in 2018 and will result in a gain of approximately $40 million that we plan to defer as a regulatory liability.

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 Non-members

Revenues from 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 under its rates for providing energy imbalance service. Excess energy is the result of changes in our power supply resources, differences between actual and forecasted needs, and changes in market conditions.

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 and energy sales in MWh by type of purchaser for the three and six months ended June 30, 2018 and 2017, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Revenues from sales to:				
Member distribution cooperatives				
Energy revenues	$ 105,495	$ 88,339	$ 244,230	$ 197,273
Demand revenues	97,328	64,906	182,895	141,274
Total revenues from sales to member distribution cooperatives	202,823	153,245	427,125	338,547
Non-members	23,829	3,662	27,536	8,139
Total operating revenues	$ 226,652	$ 156,907	$ 454,661	$ 346,686
Energy sales to:	(in MWh)			
Member distribution cooperatives	2,534,684	2,446,721	5,991,720	5,463,075
Non-members	663,243	91,165	743,530	212,277
Total energy sales	3,197,927	2,537,886	6,735,250	5,675,352
Average cost of energy to member distribution cooperatives (per MWh)	$ 41.62	$ 36.10	$ 40.76	$ 36.11
Average total cost to member distribution cooperatives (per MWh)	$ 80.02	$ 62.63	$ 71.29	$ 61.97

Sales of power and renewable energy credits for the three and six months ended June 30, 2018 and 2017, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Member distribution cooperatives				
Sales to member distribution cooperatives, excluding renewable energy credit sales	$ 202,822	$ 153,242	$ 427,113	$ 338,531
Renewable energy credit sales to member distribution cooperatives	1	3	12	16
Total sales to member distribution cooperatives	$ 202,823	$ 153,245	$ 427,125	$ 338,547
Non-members				
Sales to non-members, excluding renewable energy credit sales	$ 23,829	$ 3,100	$ 26,971	$ 6,648
Renewable energy credit sales to non-members	—	562	565	1,491
Total sales to non-members	$ 23,829	$ 3,662	$ 27,536	$ 8,139

Member Distribution Cooperatives

For the three and six months ended June 30, 2018, total revenues from sales to our member distribution cooperatives were 32.4% higher and 26.2% higher, respectively, as compared to the same periods in 2017, due to increases in energy and demand revenues. Energy revenues increased $17.2 million, or 19.4%, and $47.0 million, or 23.8%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017, due to the increase in the average cost of energy sold to our member distribution cooperatives and an increase in energy sales in MWh to our member distribution cooperatives. The average cost of energy sold to our member distribution cooperatives increased 15.3% and 12.9%, respectively, for the three and six months ended June 30, 2018, due to the 11.1% and 3.7% total energy rate increases we implemented January 1, 2018 and April 1, 2018, respectively. The energy sales in MWh to our member distribution cooperatives increased 3.6% and 9.7%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017. Absent the impact of the removal of load under the limited exception under wholesale power contracts beginning May 1, 2018, our energy sales in MWh would have increased 6.0% and 10.8%, respectively. Demand revenues increased $32.4 million, or 50.0%, and $41.6 million, or 29.5%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017, primarily due to the increase in transmission expense and recognition of Wildcat Point expenses related to operations and maintenance, administrative and general, depreciation, and interest charges.

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:

Date	% Change
January 1, 2017	(6.7)
January 1, 2018	11.1
April 1, 2018	3.7

Non-members

For the three and six months ended June 30, 2018, revenues from sales to non-members increased $20.2 million and $19.4 million, respectively, as compared to the same periods in 2017. 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 power supply resources, differences between actual and forecasted needs, and changes in market conditions.

Operating Expenses

The following is a summary of the components of our operating expenses for the three and six months ended June 30, 2018 and 2017:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Fuel	$ 49,523	$ 20,498	$ 82,439	$ 38,181
Purchased power	61,441	80,729	228,586	202,845
Transmission	32,083	23,979	65,229	47,721
Deferred energy	16,704	(4,705)	(35,568)	(26,243)
Operations and maintenance	19,599	12,099	33,000	24,572
Administrative and general	11,653	11,309	23,255	22,439
Depreciation and amortization	17,083	11,340	28,761	22,683
Amortization of regulatory asset/liability, net	(1,838)	(850)	(4,641)	(20)
Accretion of asset retirement obligations	1,331	1,257	2,661	2,512
Taxes, other than income taxes	2,581	2,087	4,718	4,191
Total Operating Expenses	$ 210,160	$ 157,743	$ 428,440	$ 338,881

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 $52.4 million, or 33.2%, and $89.6 million, or 26.4%, respectively, for the three and six months ended June 30, 2018, respectively, as compared to the same periods in 2017. The increase for the three months ended June 30, 2018, was primarily due to increases in fuel, deferred energy, and transmission, partially offset by the decrease in purchased power. The increase for the six months ended June 30, 2018, was primarily due to increases in fuel, purchased power, and transmission, partially offset by the decrease in deferred energy.

- Fuel expense increased $29.0 million, or 141.6%, and $44.3 million, or 115.9%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017. Wildcat Point achieved commercial operation on April 17, 2018, and generated 954,748 MWh in the second quarter of 2018. Additionally, generation from our combustion turbine facilities increased 176.7% and 210.5%, respectively, for the three and six months ended June 30, 2018, due to PJM's economic dispatch of these facilities.

- Purchased power expense, which includes the cost of purchased energy and capacity, decreased $19.3 million, or 23.9%, and increased $25.7 million, or 12.7%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017. Purchased energy decreased $14.9 million, or 20.5%, for the three months ended June 30, 2018, due to the 29.8% decrease in the volume of purchased energy, partially offset by the 13.2% increase in the average cost of purchased energy. Purchased energy increased $30.6 million, or 16.4%, for the six months ended June 30, 2018, due to the 25.1% increase in the average cost of purchased energy, partially offset by the 6.9% decrease in the volume of purchased energy.

- Transmission expense increased $8.1 million, or 33.8%, and $17.5 million, or 36.7%, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017, primarily due to increases in PJM charges for network transmission services.

- Deferred energy expense increased $21.4 million for the three months ended June 30, 2018, and decreased $9.3 million for the six months ended June 30, 2018, as compared to the same periods in 2017. For the three months ended June 30, 2018 and 2017, we over-collected $16.7 million and under-collected $4.7 million, respectively. For the six months ended June 30, 2018 and 2017, we under-collected $35.6 million, and $26.2 million, respectively. Deferred energy expense represents the difference between energy revenues and energy expenses. For further discussion on deferred energy, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Deferred Energy" in Item 7 of our 2017 Annual Report on Form 10-K.

Other Items

Investment Income

Investment income decreased $4.0 million and $3.7 million, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017, primarily due to decreased earnings on our nuclear decommissioning trust.

Interest Income on North Anna Unit 3 Cost Recovery

Interest income on North Anna Unit 3 cost recovery represents interest received from Virginia Power related to the recovery of a portion of our North Anna Unit 3 regulatory asset. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Other Items—Interest Income on North Anna Unit 3 Cost Recovery" in Item 7 of our 2017 Annual Report on Form 10-K.

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, 2018 and 2017, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Interest on long-term debt	$ (15,549)	$ (13,790)	$ (31,103)	$ (27,572)
Interest on revolving credit facility	(654)	(1,201)	(1,255)	(2,080)
Other interest	(390)	(240)	(548)	(419)
Total interest charges	(16,593)	(15,231)	(32,906)	(30,071)
Allowance for borrowed funds used during construction	1,671	8,904	10,894	17,500
Interest charges, net	$ (14,922)	$ (6,327)	$ (22,012)	$ (12,571)

Interest charges, net increased $8.6 million, and $9.4 million, respectively, for the three and six months ended June 30, 2018, as compared to the same periods in 2017, substantially due to the decrease in allowance for borrowed funds used during construction (capitalized interest) related to Wildcat Point and the increase in interest on long-term debt. We issued $250 million of long-term debt in July 2017.

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, 2018, as compared to the same periods in 2017.

Financial Condition

The principal changes in our financial condition from December 31, 2017 to June 30, 2018, were caused by increases in property, plant, and equipment, assets held for sale, revolving credit facility, deferred energy, and accounts payable, and decreases in construction work in progress, lease deposits, and obligations under long-term lease.

- Property, plant, and equipment increased $696.9 million, primarily due to the reclassification of Wildcat Point from construction work in progress, partially offset by the reclassification of Rock Springs to assets held for sale.
- Assets held for sale increased $72.5 million due to the reclassification of property, plant, and equipment, and accumulated depreciation associated with Rock Springs.
- Revolving credit facility increased $52.7 million due to outstanding borrowings under this facility.
- Deferred energy increased $35.6 million as a result of the under-collection of our energy costs in 2018. The deferred energy balance was an under-collection of $3.7 million and $39.2 million at December 31, 2017, and June 30, 2018, respectively.
- Accounts payable increased $18.3 million primarily due to increased construction-related payables.
- Construction work in progress decreased $791.8 million primarily due to the reclassification of Wildcat Point to property, plant, and equipment.
- Lease deposits and obligations under long-term lease decreased $41.9 million and $39.9 million, respectively, due to the payments and amortization related to our obligations under the Clover lease. For further discussion of the Clover lease, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Significant Contingent Obligations—Clover Lease" in Item 7 of our 2017 Annual Report on Form 10-K.

Liquidity and Capital Resources

Sources

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

Operations

During the first six months of 2018 and 2017, our operating activities provided cash flows of $7.3 million and $4.6 million, respectively. Operating activities in 2018 were primarily impacted by the $35.6 million change in deferred energy due to the under-collection of our energy costs in 2018.

Revolving Credit Facility

We maintain a revolving credit facility to cover our short-term and medium-term funding needs that are not met by cash from operations or other available funds. Commitments under this syndicated credit agreement extend until March 3, 2023. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through March 3, 2023. As of June 30, 2018, we had outstanding under this facility, $96.1 million in borrowings and $2.5 million in letters of credit. As of December 31, 2017, we had outstanding under this facility, $43.4 million in borrowings and $12.0 million in letters of credit.

Financings

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

Uses

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the second quarter of 2018.

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. On April 13, 2015, we received an initial decision from the hearing judge. On January 19, 2017, FERC issued its order on the hearing judge's initial decision. On February 21, 2017, we submitted our compliance filing, revising the formula rate as we previously suggested and FERC directed in the January 19, 2017 order. Additionally, on February 21, 2017, Bear Island filed a request for rehearing. On March 22, 2017, FERC issued an order granting rehearing of its initial order for the limited purpose of FERC's further consideration of the matter. On March 22, 2018, FERC issued an order denying Bear Island's request for rehearing and accepted our February 21, 2017 compliance filing that revised the formula rate as directed by FERC's January 19, 2017 order. We filed a refund report with FERC on April 23, 2018, that calculated the difference between rates charged under our rate schedule since January 1, 2014, and rates that would have been charged under the revised rate schedule submitted in our February 21, 2017 compliance filing. On July 24, 2018, FERC accepted the refund report, which will result in a reallocation of costs among our member distribution cooperatives and will not result in any change to our operating revenues.

Recovery of Costs from PJM

On June 23, 2014, we filed a petition at FERC seeking recovery from PJM of approximately $14.9 million of unreimbursed costs, which were incurred during the first quarter of 2014 related to the dispatch of our combustion turbine generating facilities. On June 9, 2015, FERC denied our petition, on July 9, 2015, we filed a request for rehearing, and on August 10, 2015, FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. On March 1, 2016, FERC denied our request for rehearing, on April 11, 2016, we filed a Petition for Review in the United States Court of Appeals for the District of Columbia Circuit, and on October 24, 2017, the court heard oral arguments. On June 15, 2018, the court denied our Petition for Review. Additionally, we have followed the legal process to preserve our right to pursue this matter in the Commonwealth of Virginia. We have not recorded a receivable related to this matter.

Wildcat Point

On April 17, 2018, Wildcat Point, an approximate 1,000 MW natural gas-fueled combined cycle generation facility, achieved commercial operation and was available for dispatch by PJM.

The facility originally was scheduled to become operational in mid-2017. WOPC, a joint venture between PCL Industrial Construction Company and Sargent & Lundy, L.L.C., as the EPC contractor, claims the delay was associated with the incurrence of additional work and other matters, including alleged misrepresentation in the EPC contract, for which it will seek recovery, in whole or in part, from its subcontractors and us. On May 24, 2017, WOPC filed a complaint against Alstom and us, in the United States District Court for the District of Maryland. An amended complaint was filed on July 21, 2017. On August 21, 2017, motions were filed by Alstom and us to transfer venue from the United States District Court for the District of Maryland to the United States District Court for the Eastern District of Virginia and on November 7, 2017, these motions were granted. We have reviewed the asserted claims of WOPC against us and believe they are without merit. We have not recorded any liability related to these claims as we do not believe any liability is estimable or probable. We intend to vigorously defend against these claims.

Additionally, on September 29, 2017, we filed a complaint in the United States District Court for the Eastern District of Virginia against WOPC, alleging that WOPC breached the EPC contract. On November 16, 2017, the United States District Court for the Eastern District of Virginia ordered that the WOPC complaint against Alstom and us, our complaint against WOPC, and a separate complaint filed by WOPC against Mitsubishi on May 9, 2017, be consolidated into one case. On June 27, 2018, an order was issued establishing January 9, 2019 as the date to check the status of discovery, set summary judgement deadlines, and set a trial date.

If it is ultimately determined that we owe any such amounts to WOPC, the amounts are not expected to have a material impact on our financial position or results of operations due to our ability to collect such amounts through rates to 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 2017 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 6. EXHIBITS

10.1	Asset Purchase Agreement by and among Old Dominion Electric Cooperative as seller and Essential Power Rock Springs, LLC as buyer dated as of June 14, 2018
31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a)
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

SIGNATURE

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

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

Date: August 8, 2018

/s/ BRYAN S. ROGERS

Bryan S. Rogers
Senior Vice President and Chief Financial Officer
(Principal financial officer)

Exhibit 31.1

CERTIFICATIONS

I, Marcus M. Harris, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;

2. Based on my knowledge, this 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-15(e) and 15d-15(e) 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 designed 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 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 of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses 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, 2018

/s/ MARCUS M. HARRIS

Marcus M. Harris
President and Chief Executive Officer
(Principal executive officer)

Exhibit 31.2

CERTIFICATIONS

I, Bryan S. Rogers, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;

2. Based on my knowledge, this 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-15(e) and 15d-15(e) 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 designed 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 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 of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses 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, 2018

/s/ BRYAN S. ROGERS

Bryan S. Rogers
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, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Marcus M. Harris, 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, 2018

/s/ MARCUS M. HARRIS
Marcus M. Harris
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, 2018 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Bryan S. Rogers, 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, 2018

/s/ BRYAN S. ROGERS
Bryan S. Rogers
Senior Vice President and Chief Financial Officer
(Principal financial officer)