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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2019

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)

Securities registered pursuant to Section 12(b) of the Act: NONE

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act? Yes ☐ No ☒

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act (the "Exchange Act"). Yes ☒ No ☐

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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 every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

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

Large 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 Exchange Act Rule 12b-2). Yes ☐ No ☒

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant. NONE

Indicate the number of shares outstanding of each of the Registrant's classes of common stock. The Registrant is a membership corporation and has no authorized or outstanding equity securities.

Documents incorporated by reference: NONE

OLD DOMINION ELECTRIC COOPERATIVE

2019 ANNUAL REPORT ON FORM 10-K

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
ACE	Affordable Clean Energy Rule
ACES	Alliance for Cooperative Energy Services Power Marketing, LLC
Alstom	Alstom Power, Inc.
ASU	Accounting Standards Update
CAA	Clean Air Act
CCRs	Coal combustion residuals
CEC	Choptank Electric Cooperative, Inc.
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Clover	Clover Power Station
CO_2	Carbon dioxide
COO	Chief Operating Officer
CSAPR	Cross-State Air Pollution Rule
DEC	Delaware Electric Cooperative, Inc.
DPSC	Delaware Public Service Commission
DOE	U.S. Department of Energy
EGU	Electric generating unit
EPA	Environmental Protection Agency
EPACT	Energy Policy Act of 2005, as amended
EPC	Engineering, procurement, and construction
EPRS	Essential Power Rock Springs, LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
GAAP	Accounting principles generally accepted in the United States
GHG	Greenhouse gases
Indenture	Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated January 1, 2011, of ODEC with Branch Banking and Trust Company, as trustee, as amended and supplemented
IRC	Internal Revenue Code of 1986, as amended
LIBOR	London Interbank Offered Rate
Louisa	Louisa Power Station
Marsh Run	Marsh Run Power Station
MATS	Mercury and Air Toxics Standards
Mitsubishi	Mitsubishi Hitachi Power Systems Americas, Inc.
Moody’s	Moody’s Investors Service
MPSC	Maryland Public Service Commission
MW	Megawatt(s)
MWac	Megawatt alternating current
MWh	Megawatt hour(s)
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
North Anna	North Anna Nuclear Power Station
North Anna Unit 3	A potential additional nuclear-powered generating unit at North Anna
NOVEC	Northern Virginia Electric Cooperative
NO_x	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NRECA	National Rural Electric Cooperative Association
NYMEX	New York Mercantile Exchange

Abbreviation or Acronym	Definition
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
PPA	Pension Protection Act
RCRA	Resource Conservation and Recovery Act, as amended
REC	Rappahannock Electric Cooperative
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model
RPS	Renewable portfolio standards
RTO	Regional transmission organization
RUS	U.S. Department of Agriculture Rural Utilities Service
S&P	Standard & Poor’s Financial Services LLC
SEPA	Southeastern Power Administration
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SVEC	Shenandoah Valley Electric Cooperative
TEC	TEC Trading, Inc.
VAPCB	Virginia Air Pollution Control Board
VDEQ	Virginia Department of Environmental Quality
Virginia Power	Virginia Electric and Power Company
VSCC	Virginia State Corporation Commission
Wildcat Point	Wildcat Point Generation Facility
WOPC	White Oak Power Constructors
XBRL	Extensible Business Reporting Language

PART I

ITEM 1. BUSINESS

OVERVIEW

Old Dominion Electric Cooperative was incorporated under the laws of the Commonwealth of Virginia in 1948 as a not-for-profit power supply cooperative. We are organized for the purpose of supplying the power our member distribution cooperatives require to serve their customers on a cost-effective basis. We serve their power requirements pursuant to long-term, all-requirements wholesale power contracts. Through our member distribution cooperatives, we served approximately 600,000 retail electric customers (meters), representing a total population of approximately 1.5 million people in 2019.

We supply our member distribution cooperatives' power requirements, consisting of demand requirements and energy requirements, through a portfolio of resources including owned generating facilities, power purchase contracts, and spot market energy purchases. Our generating facilities are fueled by a mix of natural gas, nuclear, coal, and fuel oil. We are a member of a regional transmission organization, PJM, and we participate in its energy, capacity, and transmission services markets to serve our member distribution cooperatives. See "Power Supply Resources" below and "Properties" in Item 2 for a description of these resources.

We are owned entirely by our members, which are the primary purchasers of the power we sell. We have two classes of members. Our Class A members are customer-owned electric distribution cooperatives that supply the power requirements of their retail customers. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our member distribution cooperatives primarily serve rural, suburban, and recreational areas of the mid-Atlantic region. See "Members—Service Territories and Customers" below.

We are a power supply cooperative. In general, a cooperative is a business organization owned by its members, which are also either the cooperative's wholesale or retail customers. Cooperatives are designed to give their members the opportunity to satisfy their collective needs in a particular area of business more effectively than if the members acted independently. As not-for-profit organizations, cooperatives are intended to provide services to their members on a cost-effective basis, in part by eliminating the need to produce profits or a return on equity in excess of required margins. Margins earned by a cooperative that are not distributed to its members constitute patronage capital, a cooperative's principal source of equity. Patronage capital is held for the account of the members without interest and returned when the board of directors of the cooperative deems it appropriate to do so.

Electric distribution cooperatives form power supply cooperatives to acquire power supply resources, typically through the construction of generating facilities or the development of other power purchase arrangements, at a lower cost than if they were acquiring those resources alone.

We are a not-for-profit electric cooperative and currently are exempt from federal income taxation under IRC Section 501(c)(12).

We are not a party to any collective bargaining agreement. We had 143 employees as of March 4, 2020.

Our principal executive office is located at 4201 Dominion Boulevard, Glen Allen, Virginia 23060. Our telephone number is (804) 747-0592.

MEMBERS

Member Distribution Cooperatives

General

Our member distribution cooperatives provide electric services, consisting of power supply, transmission services, and distribution services (including metering and billing services) to residential, commercial, and industrial customers. We have eleven member distribution cooperatives that serve customers in 70 counties in Virginia, Delaware, and

Maryland. The member distribution cooperatives' distribution business involves the operation of substations, transformers, and electric lines that deliver power to their customers.

Eight of our member distribution cooperatives provide electric services on the Virginia mainland:

BARC Electric Cooperative
Community Electric Cooperative
Mecklenburg Electric Cooperative
Northern Neck Electric Cooperative
Prince George Electric Cooperative
Rappahannock Electric Cooperative
Shenandoah Valley Electric Cooperative
Southside Electric Cooperative

Three of our member distribution cooperatives provide electric services on the Delmarva Peninsula:

A&N Electric Cooperative in Virginia
Choptank Electric Cooperative, Inc. in Maryland
Delaware Electric Cooperative, Inc. in Delaware

The member distribution cooperatives are not our subsidiaries, but rather our owners. We have no interest in their assets, liabilities, equity, revenues, or margins.

Revenues from our member distribution cooperatives and the percentage each contributed to total revenues from sales to our member distribution cooperatives in 2019 were as follows:

Member Distribution Cooperatives	**Revenues**	
	(in millions)	
Rappahannock Electric Cooperative	$ 279.7	31.1%
Shenandoah Valley Electric Cooperative	168.4	18.7
Delaware Electric Cooperative, Inc.	121.6	13.5
Choptank Electric Cooperative, Inc.	83.1	9.3
Southside Electric Cooperative	69.8	7.8
A&N Electric Cooperative	54.7	6.1
Mecklenburg Electric Cooperative	45.1	5.0
Prince George Electric Cooperative	26.9	3.0
Northern Neck Electric Cooperative	24.1	2.7
Community Electric Cooperative	14.1	1.6
BARC Electric Cooperative	11.0	1.2
Total	$ 898.5	100.0%

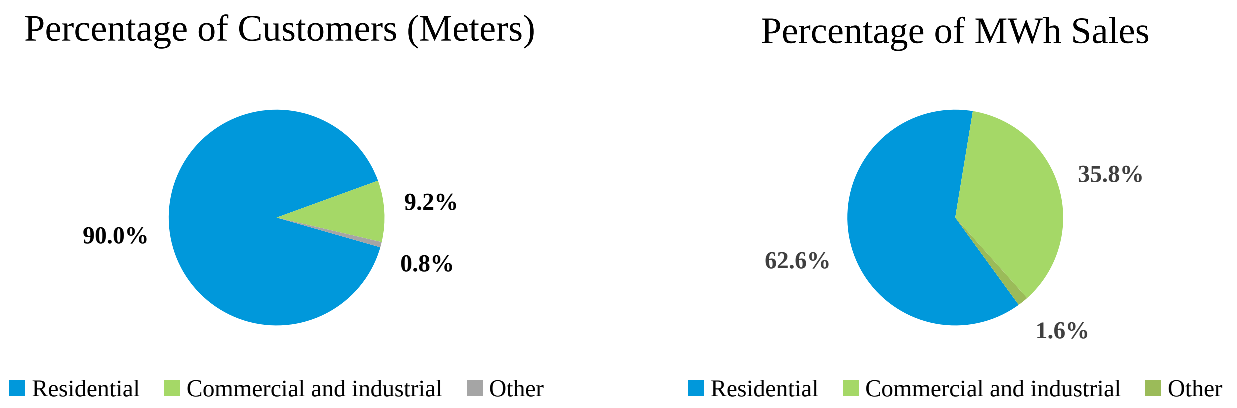
In 2019, there was no individual customer of any of our member distribution cooperatives that constituted 1% or more of our revenues from our member distribution cooperatives.

Service Territories and Customers

The territories served by our member distribution cooperatives cover large portions of Virginia, Delaware, and Maryland. These service territories range from the extended suburbs of Washington, D.C. to the North Carolina border and from the Atlantic shores of Virginia, Delaware, and Maryland to the Appalachian Mountains.

Our member distribution cooperatives' service territories encompass primarily rural, suburban, and recreational areas. Our member distribution cooperatives' customers' requirements for capacity and energy generally are seasonal and increase in winter and summer as home heating and cooling needs increase and then decline in the spring and fall as the weather becomes milder. Our member distribution cooperatives also serve major industries which include manufacturing, poultry, telecommunications, agriculture, forestry and wood products, health care, and recreation.

Our member distribution cooperatives' sales of energy in 2019 totaled approximately 12,000,000 MWh. These sales were divided by customer class as follows:



From 2014 through 2019, our eleven member distribution cooperatives experienced a compound annual growth rate of 1.4% and 0.8%, in the number of customers (meters) and energy sales measured in MWh, respectively.

Our eleven member distribution cooperatives' average number of customers per mile of energized line has been relatively unchanged from 2014 to 2019 at approximately 9.5 customers per mile. System densities of our member distribution cooperatives in 2019 ranged from 6.3 customers per mile in the service territory of BARC Electric Cooperative to 14.5 customers per mile in the service territory of A&N Electric Cooperative. In 2019, the average service density for all electric distribution cooperatives in the United States was approximately 8 customers per mile.

Delaware and Maryland each currently grant all retail customers the right to choose their power supplier. Virginia currently grants a limited number of large retail customers the right to choose their power suppliers and then only in very limited circumstances. The laws of each state grant utilities, including our member distribution cooperatives, the exclusive right to provide transmission and distribution (including metering and billing) services and to be the default providers of power to their customers in service territories certified by their respective state public service commissions. See "Regulation of Member Distribution Cooperatives" and "Competition" below.

Wholesale Power Contracts

Our financial relationships with our member distribution cooperatives are based primarily on our contractual arrangements for the supply of power and related transmission and ancillary services. These arrangements are set forth in our wholesale power contracts with our member distribution cooperatives that are effective until January 1, 2054, and beyond this date unless either party gives the other at least three years notice of termination. The wholesale power contracts are all-requirements contracts. Each contract obligates us to sell and deliver to a member distribution cooperative, and obligates that member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so.

An exception to the all-requirements obligations of our member distribution cooperatives relates to the ability of our eight mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from SEPA, a federal power marketing administration. We estimate that purchases under this exception constituted approximately 2% of our member distribution cooperatives' total energy requirements in 2019.

There are two additional limited exceptions to the all-requirements nature of the contracts. One exception 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. The other exception permits our member distribution cooperatives to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. As of December 31, 2019, none of our member distribution cooperatives had utilized this exception.

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 178 MW of demand and associated energy. The following table summarizes the cumulative removal of load requirements under this exception.

As of December 31,	**MW**
2017	65
2018	107
2019	108

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.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formula rate. The formula rate, which has been filed with and accepted by FERC, is designed to recover our total cost of service and create a firm equity base. See "Regulation—Rate Regulation" below and "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate" in Item 7.

More specifically, the formula rate is intended to meet all of our costs, expenses, and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement, and decommissioning of our generating plants, transmission system, or related facilities; services provided to the member distribution cooperatives; and the acquisition and transmission of power or related services, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);
- any additional cost or expense, imposed or permitted by any regulatory agency; and
- additional amounts necessary to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory, and governmental requirements that apply to us from time to time.

In accordance with the wholesale power contracts, our board of directors will review our formula rate at least every three years to determine if it reflects and recovers all costs and expenses indicated above, and if it represents the best way to allocate these costs and expenses among our member distribution cooperatives. In making this review, our board of directors will consider if the formula rate results in the proper price signals to our member distribution cooperatives. Due to changes in the energy sector generally and PJM specifically, the review of our formula rate often identifies new or changing bases for the costs we incur. We will not modify our formula rate in any manner that would result in a failure to recover all of our costs and other amounts described above.

A committee of our board of directors is currently conducting a review of our formula rate. Because modifications to our formula rate are not intended to modify the aggregate amount that we collect from our member distribution cooperatives, but rather how we allocate that aggregate amount, the opportunity exists for disagreements with or among our member distribution cooperatives, or with us, regarding the best formula rate structure. As the factors impacting our costs change with the evolving energy sector and PJM market, the potential for these disagreements increases. One of our member distribution cooperatives, SVEC, has indicated it is concerned with potential modifications to our formula rate that the board committee is considering but has not yet recommended to the entire board of directors for approval. We are working with our member distribution cooperatives, including SVEC, to assure that all concerns are fully understood and to reach a resolution on any modifications. We cannot be certain, however, that a mutually agreeable resolution will occur.

We currently anticipate that we will file an application with FERC in 2020 for approval of modifications to our formula rate. Given the likely reallocation of some of our costs, the possibility exists that one or more parties may intervene in the FERC proceeding and seek to change the modifications we propose, or request that FERC reject the modifications altogether. We anticipate that if FERC approval of the requested modifications are contested, delayed, or rejected, we will continue to recover all of our costs and other amounts under the wholesale power contracts.

Regulation of Member Distribution Cooperatives

Of our 11 member distribution cooperatives, eight currently participate in RUS loan or guarantee programs. These member distribution cooperatives have entered into loan documents with RUS that we understand contain affirmative and negative covenants, including with respect to matters such as accounting, issuances of securities, rates and charges for the sale of power, construction or acquisition of facilities, and the purchase and sale of power. In addition, we understand financial covenants in these member distribution cooperatives' loan documents require them to design rates to achieve an interest coverage ratio and a debt service coverage ratio. Finally, we understand that the principal loan documentation of our member distribution cooperatives that do not participate in RUS loan or guarantee programs contains similar covenants.

Our member distribution cooperatives in Virginia are subject to rate regulation by the VSCC in the provision of electric services to their customers, but they have the ability to pass through changes in their wholesale power costs, including the demand and energy costs we charge our member distribution cooperatives, to their customers. Our Virginia member distribution cooperatives also may adjust their rates for distribution service by a maximum net increase or decrease of 5%, on a cumulative basis, in any three-year period without approval by the VSCC. Additionally, they may make adjustments to their rates to collect fixed costs through a new or modified fixed monthly charge rather than through volumetric charges associated with energy usage, so long as such adjustments are revenue neutral.

The MPSC regulates the rates and services offered by our Maryland member distribution cooperative, CEC, other than wholesale power costs, which are a pass-through to CEC's customers. Our Delaware member distribution cooperative, DEC, is not regulated by the DPSC, including with respect to wholesale power costs, which are a pass-through to its customers.

We are not subject to any RPS, however, DEC is subject to RPS. DEC meets the RPS through purchases of renewable energy credits, and owned and purchased resources pursuant to the 5% or 5 MW exception in its wholesale power contract with us. See "Wholesale Power Contracts" above.

Competition

Delaware and Maryland each have laws unbundling the power component (also known as the generation component) of electric service to retail customers, while maintaining regulation of transmission and distribution services. All retail customers in Delaware, including customers of DEC, are currently permitted to purchase power from a registered supplier only after DEC approves the supplier's ability to do business in its service territory. All retail customers in Maryland, including customers of CEC, are currently permitted to purchase power from the registered supplier of their choice. As of March 1, 2020, no retail customer of DEC or CEC has switched to an alternative power supplier.

In Virginia, retail choice in the selection of a power supplier is available to customers that consume at least 5 MW of power individually or in the aggregate (with aggregation subject to the approval of the VSCC) and that do not account for more than 1% of the incumbent utility's peak load during the past year. Currently, no customer of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any customer whose noncoincident peak demand exceeds 90 MW. Additionally, all Virginia retail customers are permitted to select an alternative power supplier that provides 100% renewable energy if their incumbent utility, such as one of our member distribution cooperatives, does not offer this same option. As of December 31, 2019, eight of our nine Virginia member distribution cooperatives provided this option.

Currently, we do not anticipate that any of these limited rights to retail choice of our member distribution cooperatives' customers, individually or in the aggregate, will have a material impact on our financial condition, results of operations, or cash flows.

TEC

TEC is owned by our member distribution cooperatives and currently is our only Class B member. We have a power sales contract with TEC under which we may sell to TEC power that we do not need to meet the needs of our member distribution cooperatives. TEC then sells this power to the market under market-based rate authority granted by FERC. Additionally, we have a separate contract under which we may purchase natural gas from TEC. TEC does not engage in speculative trading.

POWER SUPPLY RESOURCES

General

We provide power to our members through a combination of our interests in Wildcat Point, a natural gas-fired combined cycle generation facility; North Anna, a nuclear power station; Clover, a coal-fired generation facility; two natural gas-fired combustion turbine facilities (Louisa and Marsh Run, and prior to September 14, 2018, 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 past three years were as follows:

	Year Ended December 31,					
	2019		2018		2017	
			(in MWh and percentages)			
Generated:						
Wildcat Point [1]	3,400,633	27.2%	3,126,313	23.0%	—	—%
North Anna	1,777,573	14.2	1,855,680	13.7	1,870,626	15.7
Clover	640,119	5.1	1,437,719	10.6	1,616,377	13.6
Louisa	494,283	4.0	544,390	4.0	262,797	2.2
Marsh Run	716,390	5.8	572,434	4.2	472,447	4.0
Rock Springs [2]	—	—	212,957	1.6	143,571	1.2
Distributed Generation	2,327	—	1,434	—	605	—
Total Generated	7,031,325	56.3	7,750,927	57.1	4,366,423	36.7
Purchased:						
Other than renewable:						
Long-term and short-term	2,665,167	21.3	2,924,477	21.5	4,913,333	41.3
Spot market	2,047,654	16.4	2,091,063	15.4	1,849,489	15.5
Total Other than renewable	4,712,821	37.7	5,015,540	36.9	6,762,822	56.8
Renewable [3]	752,405	6.0	808,052	6.0	777,505	6.5
Total Purchased	5,465,226	43.7	5,823,592	42.9	7,540,327	63.3
Total Available Energy	12,496,551	100.0%	13,574,519	100.0%	11,906,750	100.0%

(1) Wildcat Point achieved commercial operation on April 17, 2018.

(2) Rock Springs and related assets were sold on September 14, 2018.

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

In 2019, our generating facilities satisfied approximately 93.1% of our PJM capacity obligation. For a description of our generating facilities, see "Properties" in Item 2. In 2019, we obtained the remainder of our PJM capacity obligation through the PJM RPM capacity auction process and purchased capacity contracts. See "PJM" below. The energy requirements not met by our owned generating facilities were obtained from multiple suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. See "Power Purchase Contracts" below.

In 2019, our peak demand obligation to our member distribution cooperatives occurred in January and was 2,954 MW.

We plan to continue purchasing energy in the future by utilizing a combination of physically-delivered forward power purchase contracts, as well as spot market purchases. As we have done in the past, we expect to adjust our portfolio of power supply resources to reflect our projected power requirements and changes in the market. To assist us in these efforts, we engage ACES, an energy trading and risk management company. Specifically, ACES assists us in negotiating power purchase contracts, evaluating the credit risk of counterparties, modeling our power requirements, bidding and dispatch of the generating facilities that we operate, and executing and settling energy transactions. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Power Supply Planning

By utilizing various long-term and short-term planning processes and models, we continually evaluate power supply options available to us to meet the needs of our member distribution cooperatives. We have policies that establish targets that define how our projected power needs will be met, and one of the ways we manage these targets is the utilization of hedging. We use hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power and fuel market price risks. These hedging instruments have varying time periods ranging from one month to multiple years in advance. Additionally, we evaluate other power supply options including the acquisition, development, or disposition of generating facilities.

PJM

PJM is an RTO that coordinates the transmission of wholesale electricity in all or parts of 13 states and the District of Columbia. As a federally regulated RTO, PJM must act independently and impartially in managing the regional transmission system and the wholesale electricity market. PJM is primarily responsible for ensuring the reliability of the largest centrally dispatched energy market in North America. PJM coordinates the continuous buying, selling, and delivery of wholesale electricity throughout its members' service territories. PJM system operators continuously conduct dispatch operations and monitor the status of the transmission grid of its participants. PJM also oversees a regional planning process for transmission expansion to ensure the continued reliability of the PJM electric system. PJM coordinates and establishes policies for the generation, purchase, and sale of capacity and energy in the control areas of its members.

All of our member distribution cooperatives' service territories are located in PJM. As a member of PJM, we are subject to the operations of PJM, and our generating facilities are under dispatch control of PJM. We transmit power to our member distribution cooperatives through the transmission facilities subject to operational control of PJM. We have agreements with PJM that provide us with access to transmission facilities under PJM's operational control as necessary to deliver energy to our member distribution cooperatives. We own a limited amount of transmission facilities. See "Properties—Transmission" in Item 2.

PJM balances its participants' power requirements with the power resources available to supply those requirements. Based on this evaluation of supply and demand, PJM schedules and dispatches available generating facilities throughout its region in a manner intended to meet the demand for energy in the most reliable and cost-effective manner. Thus PJM directs the dispatch of these facilities even though it does not own them. When PJM cannot dispatch the most economical generating facilities due to transmission constraints, PJM will dispatch more expensive generating facilities to meet the required power requirements. PJM participants whose power requirements cause the redispatch are obligated to pay the additional costs to dispatch the more expensive generating facilities. These additional costs are commonly referred to as congestion costs. PJM conducts the auction of financial transmission rights for future periods to provide market participants an opportunity to hedge these congestion costs.

The PJM energy market consists of day-ahead and real-time markets. PJM's day-ahead market is a forward market in which hourly locational marginal prices are calculated for the following day based on the prices at which the owners of generating facilities, including ODEC, offer to run their facilities to meet the requirements of energy customers. PJM's real-time market is a spot market in which current locational marginal prices are calculated at five-minute intervals.

PJM rules require that load serving entities, such as ODEC, meet certain minimum capacity obligations. These obligations can be met through a combination of owned generation resources and purchases under bilateral agreements and from forward capacity auctions under PJM's capacity construct, known as RPM. The purpose of PJM's capacity construct is to develop a longer-term pricing program for capacity resources, to provide localized pricing for capacity, and to reduce the resulting investment risk to owners of generating resources, thus encouraging new investment in generating facilities. The value of capacity resources can vary by location and RPM provides for the recognition of the locational value. To date, PJM has conducted capacity auctions for capacity to be supplied through May 31, 2022. Each annual auction is typically held 36 months before each subsequent delivery year, and incremental auctions may be held at prescribed dates after the base residual auction for each delivery year to adjust for changes to the load forecast and the availability of capacity. Currently, the capacity auctions are suspended until PJM complies with FERC's ruling on PJM's Minimum Offer Price Rule.

Concurrent with the PJM delivery year beginning June 1, 2016, the PJM tariff provides for a new component referred to as capacity performance, which is intended to improve the reliability of the power grid by increasing the availability of generating units, especially during emergency conditions. Generation owners, such as ODEC, could earn increased compensation for capacity for some of their generating units and will be exposed to significantly higher charges if their generation units do not perform during emergency conditions. For the PJM delivery year beginning June 1, 2016, qualifying generating units were allowed to be voluntarily offered into PJM's capacity auction as a capacity performance unit. A unit not offered as a capacity performance unit, known as a base capacity unit, will be excluded from the assessment of the charges for non-performance during the winter months. Starting with the delivery year beginning June 1, 2020, PJM will require all generating resources to be offered as capacity performance units, eliminating the base capacity option.

Power Purchase Contracts

We purchase significant amounts of power in the market from investor-owned utilities and power marketers through long-term and short-term physically-delivered forward power purchase contracts. We also purchase power in the spot energy market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. See "Risk Factors" in Item 1A. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy and sales of excess energy. Additionally, we utilize policies, procedures, and various hedging instruments to manage our power market price risks. These policies and procedures, developed in consultation with ACES, are designed to strike an appropriate balance between minimizing costs and reducing energy cost volatility. See "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Renewables

We have contracts with companies that own and operate wind, solar, and landfill gas facilities. We purchase nearly 300 MWac of capacity from renewable facilities that are operational. In 2018, we entered into an additional contract to purchase the output of a 75 MWac solar facility that is under development. Our renewable contracts allow us to buy output, including renewable energy credits, from the renewable facilities at predetermined prices. We sell these renewable energy credits to our member distribution cooperatives and non-members. We do not own or operate any of these facilities and are not responsible for their operational costs or performance. During 2019, we entered into an agreement with EDF Renewables North America to develop distributed solar projects across our service territories in Virginia, Delaware, and Maryland, and we will purchase the power from these projects through power purchase agreements. We anticipate these distributed solar projects will have a capacity greater than 50 MWac and be operational in 2020 and 2021.

Fuel Supply

Natural Gas

Wildcat Point and our combustion turbine facilities are fueled by natural gas and are located adjacent to natural gas transmission pipelines. We are responsible for procuring the natural gas to be used by all of our units at these facilities and have developed and utilize a natural gas supply strategy. The strategy includes securing transportation contracts and incorporating the ability to use No. 2 distillate fuel oil as a backup fuel for Louisa and Marsh Run. We have identified our primary natural gas suppliers and have negotiated the contracts needed for procurement of physical natural gas. We have put in place strategies and mechanisms to financially hedge our natural gas needs. We anticipate that sufficient supplies of natural gas will be available in the future to support the operation of Wildcat Point and our combustion turbine facilities, but significant price volatility may occur. See “Quantitative and Qualitative Disclosures About Market Risk” in Item 7A.

Nuclear

Virginia Power, as operating agent of North Anna, has the sole authority and responsibility to procure nuclear fuel for the facility. Virginia Power advises us that it primarily uses long-term contracts to support North Anna’s nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices, which are dependent upon the market environment. We are not a direct party to any of these procurement contracts and we do not control their terms or duration. Virginia Power advises us that current agreements, inventories, and spot market availability are expected to support North Anna’s current and planned fuel supply needs for the near term and that additional fuel is purchased as required to attempt to ensure optimal cost and inventory levels.

Under the Nuclear Waste Policy Act of 1982, the DOE is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as North Anna, in accordance with contracts executed with the DOE. The DOE did not begin accepting spent fuel in 1998 as specified in its contract with Virginia Power. As a result, Virginia Power sought reimbursement for certain spent nuclear fuel-related costs incurred and in 2012 signed a settlement agreement with the DOE, which provides for periodic payments for damages. See “Note 1—Summary of Significant Accounting Policies—Nuclear Fuel” in the Notes to Consolidated Financial Statements in Item 8.

Coal

Virginia Power, as operating agent of Clover, has the sole authority and responsibility to procure coal for the facility. Virginia Power advises us that it uses both long-term contracts and short-term spot agreements to acquire the low sulfur bituminous coal used to fuel the facility. We are not a direct party to any of these procurement contracts and we do not control their terms or duration. As of December 31, 2019 and December 31, 2018, based on Clover running at full capacity, there was a 58-day and a 34-day supply of coal, respectively. We anticipate that sufficient supplies of coal will be available in the future to operate the facility when dispatched by PJM. See “Quantitative and Qualitative Disclosures About Market Risk” in Item 7A.

REGULATION

General

We are subject to regulation by FERC and, to a limited extent, state public service commissions. Some of our operations also are subject to regulation by the VDEQ, the Maryland Department of the Environment, the DOE, the NRC, and other federal, state, and local authorities. Compliance with future laws or regulations may increase our operating and capital costs by requiring, among other things, changes in the design or operation of our generating facilities.

Rate Regulation

We establish our rates for power furnished to our member distribution cooperatives pursuant to our formula rate, which has been accepted by FERC. The VSCC, the DPSC, and the MPSC do not have jurisdiction over our rates, charges, and services.

Our formula rate is intended to permit us to collect revenues, which, together with revenues from all other sources, are equal to all of our costs and expenses, plus a targeted amount equal to 20% of our total interest charges, plus additional equity contributions as approved by our board of directors. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate” in Item 7.

FERC may review our rates upon its own initiative or upon complaint and order a reduction of any rates determined to be unjust, unreasonable, or otherwise unlawful and order a refund for amounts collected during such proceedings in excess of the just, reasonable, and lawful rates.

Our charges to TEC are established under our market-based sales tariff filed with FERC.

Other Regulation

In addition to its jurisdiction over rates, FERC also regulates the issuance of securities and assumption of liabilities by us, as well as mergers, consolidations, the acquisition of securities of other utilities, and the disposition of property under FERC jurisdiction. Under FERC regulations, we are prohibited from selling, leasing, or otherwise disposing of the whole of our facilities subject to FERC jurisdiction, or any part of such facilities having a value in excess of $10 million without FERC approval. We are also required to seek FERC approval prior to merging or consolidating our facilities with those of any other entity having a value in excess of $10 million.

The VSCC, the DPSC, and the MPSC oversee the siting of our utility facilities in their respective jurisdictions.

Environmental

We are subject to federal, state, and local laws and regulations, and permits designed to both protect human health and the environment and to regulate the emission, discharge, or release of pollutants into the environment. We believe that we are in material compliance with all current requirements of such environmental laws and regulations and permits. However, as with all electric utilities, the operation of our generating units could be affected by future changes in environmental laws and regulations. We continue to monitor activity related to changes in environmental laws and regulations, including new requirements. Capital expenditures and increased operating costs required to comply with any future regulations could be significant. See "Risk Factors" in Item 1A. Our capital expenditures for environmental improvements at our generating facilities were approximately $0.3 million and $5.1 million in 2019 and 2018, respectively.

Clean Air Act ("CAA")

Currently, the most significant environmental law affecting our operations is the CAA. The CAA requires, among other things, that owners and operators of fossil fuel-fired power stations limit emissions of SO_2, particulate matter, mercury, and NO_x. Additionally, regulatory programs are in place for new units and are being proposed for existing units to limit emissions of CO_2 and other GHG. Discussed below are certain standards and regulations under the CAA that impact us.

- Cross-State Air Pollution Rule
- Acid Rain Program
- Mercury and Air Toxics Standards
- National Ambient Air Quality Standards
- Affordable Clean Energy Rule
- Greenhouse Gas Prevention of Significant Deterioration Permitting

Cross-State Air Pollution Rule ("CSAPR")

CSAPR requires 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. Based upon published allocations/new source set-aside allowances for Virginia and Maryland, we anticipate that we will continue to purchase NO_x and a limited number of SO_2 CSAPR allowances for Clover. Wildcat Point will apply for new source set-aside NO_x allowances from Maryland and will purchase allowances for any emissions that exceed the number of new source set-aside allowances received. Currently, there is an adequate supply of NO_x allowances available for purchase for Wildcat Point. The number of set-aside allowances available for Wildcat Point will depend on the number of new sources requesting the allowances. Because the CSAPR allowance market is relatively new, we cannot predict the potential financial impact of such purchases.

Acid Rain Program

Under the CAA's Acid Rain Program, each of our fossil fuel-fired plants must have SO_2 allowances equal to the number of tons of SO_2 they emit into the atmosphere annually. The total number of SO_2 allowances for all facilities is capped, and individual allowances are issued to facilities on the basis of past utilization and other factors. SO_2 allowances issued to individual sources can be traded. As a facility that was built before the Acid Rain Program, Clover receives an annual allocation of SO_2 allowances at no cost based upon its baseline operations. Our newer facilities, Louisa, Marsh Run, and Wildcat Point, however, need to obtain allowances under the Acid Rain Program. Because they are primarily gas-fired generating facilities, the number of SO_2 allowances these newer facilities must obtain is typically minimal and can be supplied from any excess SO_2 allowances allocated to Clover.

Mercury and Air Toxics Standards ("MATS")

MATS regulates mercury, acid gases, and other air toxic organic compounds from coal and oil-fired power plants. Coal and oil-fired power plants are required to meet maximum achievable control technology standards to control the pollutants regulated by MATS. Clover has demonstrated compliance with this rule and continues to submit periodic reports. We do not anticipate that any additional emissions control measures will be required to continue to comply with MATS due to the existing pollution control equipment, which removes greater than 90% of the mercury emitted from the facility.

National Ambient Air Quality Standards ("NAAQS")

As part of the NAAQS, states will be required to develop and implement plans to address sources emitting pollutants which contribute to the formation of ozone. In November 2016, the EPA published the proposed designations and SIP requirements for implementation. The EPA finalized the designations of the 2015 ozone NAAQS in June 2018. Compliance requirements are dependent upon the attainment designation and we currently anticipate that compliance may begin in 2020 and go through 2027. We currently do not anticipate any emissions control requirement changes for our existing facilities. The EPA is still developing the implementation guidance related to the NAAQS. We will continue to follow this rulemaking in order to determine potential impacts related to our facilities.

Affordable Clean Energy Rule ("ACE")

On September 6, 2019, ACE, a replacement rule for the Clean Power Plan, became effective and requires that each state implement plans to meet state-specific carbon emissions reductions no later than July 8, 2022. We have ownership interests in generating facilities in Virginia and Maryland and are exposed to the impact of inconsistent standards between states as well as the uncertainty of the implementation plans. We are closely monitoring the rulemaking related to ACE, and we currently cannot predict the impact of ACE on our existing facilities due to the uncertainties and complexities of the regulations.

Greenhouse Gas Prevention of Significant Deterioration Permitting

In 2010, the EPA issued the Tailoring Rule to address GHG emissions from stationary sources under the CAA permitting programs. The final rule set thresholds for GHG emissions that define when permits under the New Source Review Prevention of Significant Deterioration and Title V Operating Permit programs are required for new and existing industrial facilities. Regulation of GHG emissions may affect the future renewal of Title V Operating Permits for Clover, Louisa, Marsh Run, and Wildcat Point, as the rules will require that existing facilities quantify their GHGs emissions and may establish limits in their reissued operating permits.

Regional Greenhouse Gas Initiative ("RGGI")

RGGI provides the framework for and administers a cap-and-trade program to regulate and reduce CO_2 emissions among participating northeastern and Mid-Atlantic States, including Delaware and Maryland. Under the RGGI requirements, we are required to purchase RGGI CO_2 allowances for each ton of CO_2 emitted by Wildcat Point. During 2019, Wildcat Point applied for and was awarded a portion of the allowances from the Maryland clean generation set-aside account and these allowances are available for Wildcat Point to use through 2022. We continue to project that there will be an adequate supply of CO_2 allowances available for purchase to support Wildcat Point. In 2020, the Virginia

General Assembly passed legislation, yet to be signed by the governor, to authorize Virginia to join RGGI in 2021 pursuant to the regulation adopted by the VAPCB in 2019. See "Virginia CO_2 Regulation" below.

Virginia CO_2 Regulation

On April 19, 2019, the VAPCB approved a regulation that would reduce and limit CO_2 emissions from large (greater than 25 MW) electric power generating facilities by linking Virginia to the RGGI CO_2 cap and trade program. On May 2, 2019, Virginia Governor Ralph Northam signed the state budget, which included a provision inserted by the legislature that prohibits Virginia from making expenditures related to RGGI without state legislative approval. In March of 2020, the Virginia General Assembly passed legislation, yet to be signed by the governor, authorizing Virginia to join (rather than link to) RGGI in 2021 pursuant to the 2019 regulation. All CO_2 emission allowances are to be auctioned, and ODEC will have to purchase allowances for CO_2 emissions from Clover, Louisa, and Marsh Run generation facilities. The legislation requires the VAPCB to establish rules by 2025 to reduce CO_2 emissions from the electric sector between 2031 and 2050, and specifies that no emission allowances are to be issued in 2050 or future years. The VAPCB may establish its own auction program to sell allowances during the period between 2031 and 2050, or use an existing multistate trading system such as RGGI. The legislation also requires that all investor-owned utility generating facilities that emit CO_2 as a by-product of combustion close by December 31, 2045, which would include the Clover generation facility, which we co-own with Virginia Power, an investor-owned utility. The legislation also calls for the state to evaluate options for the electric sector to achieve zero greenhouse gas emissions by 2050, and to report to the legislature on the recommendations from that evaluation by January 1, 2022. ODEC will continue to be engaged in development and implementation of the Virginia CO_2 regulation process.

Clean Water Act

The Clean Water Act and applicable state laws regulate water intake structures, discharges of cooling water, storm water runoff, and other wastewater discharges at our generating facilities. Our water permits are subject to periodic review and renewal proceedings, and can be made more restrictive over time. Limitations on the thermal discharges in cooling water, or withdrawal of cooling water during low flow conditions, can restrict our operations. In 2013, the EPA proposed revising limits on certain toxic pollutants that would require most steam electric (including coal and natural gas-fired combined cycle) facilities to strengthen existing, or implement new, controls to manage water discharges from their sites. On November 3, 2015, the EPA issued the final rule, known as the Steam Electric Effluent Limitation Guidelines, which revised the guidelines to set the first limits on the levels of toxic metals in wastewater that can be discharged from power plants. The final rule sets new or additional requirements for wastewater streams from flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

In 2016, several industry parties represented by the Utility Water Act Group filed briefs in a proceeding objecting to the final rule. The briefs alleged several instances where it is believed that the EPA violated standards and procedures in producing the guidelines. On September 13, 2017, a final rule was issued postponing compliance dates for "best available technology economically achievable" effluent limitations and pretreatment standards for two waste streams of existing sources, bottom ash transport water and flue-gas desulfurization wastewater, for a period of two years. The EPA published a proposal for revised effluent limitation guideline standards for bottom ash and transport water, and scrubber wastewater in the Federal Register on November 22, 2019. Comments were due by January 21, 2020, and a final rule is expected in 2020. We do not currently expect a significant impact on our facility operations. We are currently in compliance and will continue to follow this rulemaking in order to determine potential future impacts related to our facilities.

Resource Conservation and Recovery Act, as amended ("RCRA")

The EPA regulates CCRs under the RCRA to address the risks from disposal of CCRs generated by coal combustion at electric generating facilities. The regulations governing the "Disposal of Coal Combustion Residuals for Electric Utilities" address risks related to coal ash disposal, such as leaching of contaminants into groundwater, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments affecting downstream resources. The regulations establish technical requirements for CCR landfills and surface impoundments, and for monitoring and cleanup of affected soil or groundwater. Also, under the regulations, facilities are subject to recordkeeping requirements, requirements to notify the state, and a requirement to develop and maintain a publicly available internet site containing information on its actions to comply with the elements of the final rule.

Since the regulations were adopted, the EPA has proposed revisions that are risk-based and would extend the compliance deadlines. We currently anticipate final revisions to the regulations by the end of 2020. We continue to monitor these revisions to the regulations and the potential impact on the operations at Clover.

Future Regulation

New legislative and regulatory proposals are frequently introduced on both the federal level and state level that would modify the environmental regulatory programs applicable to our facilities. Changing regulatory requirements can increase our capital and operating costs and adversely affect the ability to operate our existing facilities, as well as restrict the construction of new facilities.

ITEM 1A. RISK FACTORS

RISK FACTORS

The following risk factors and all other information contained in this report should be considered carefully when evaluating ODEC. These risk factors could affect our actual results and cause these results to differ materially from those expressed in any forward-looking statements of ODEC. Other risks and uncertainties, in addition to those that are described below, may also impair our business operations. We consider the risks listed below to be material, but you may view risks differently than we do and we may omit a risk that we consider immaterial but you consider important. An adverse outcome of any of the following risks could materially affect our business or financial condition. These risk factors should be read in conjunction with the other detailed information set forth elsewhere in this report, including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, including "Caution Regarding Forward-looking Statements," and the notes to Consolidated Financial Statements in Item 8.

Our financial condition is largely dependent upon our member distribution cooperatives.

Our financial condition is largely dependent upon our member distribution cooperatives satisfying their obligations to us under their wholesale power contracts. In 2019, 63.3% of our revenues from sales to our member distribution cooperatives were received from our three largest members, REC, SVEC, and DEC. The wholesale power contracts require our member distribution cooperatives to pay us for power furnished to them in accordance with our FERC formula rate. Our board of directors, which is composed of representatives of our members, can approve changes in the rates we charge to our member distribution cooperatives without seeking FERC approval, with limited exceptions. See "Wholesale Power Contracts" in Item 1.

One of those exceptions requiring FERC approval relates to modifications to our formula rate. The formula rate is intended to allocate our costs based on how they are incurred. As the factors impacting our costs change with the evolving energy sector and PJM market, the potential increases for disagreements with or among our member distribution cooperatives about cost allocation. We currently anticipate that we will file an application with FERC in 2020 for approval of some modifications. As a result, one or more of our member distribution cooperatives, or its customers, could challenge the proposed modifications. Such a challenge would not cause us to fail to recover all of our costs and other amounts to be collected under the wholesale power contracts, but could interfere with our ability to work as effectively as an organization as otherwise would be the case. See "Wholesale Power Contracts" in Item 1.

Our member distribution cooperatives' ability to collect their costs from their members may have an impact on our financial condition. Economic conditions may make it difficult for some customers of our member distribution cooperatives to pay their power bills in a timely manner, which could ultimately affect the timeliness of our member distribution cooperatives' payments to us.

We rely on purchases of fuel and energy from other suppliers which exposes us to market price risk and could increase our operating costs.

We supply our member distribution cooperatives with all of their power (energy and demand) requirements, with limited exceptions. Our costs to provide this energy and demand are passed through to our member distribution cooperatives under our wholesale power contracts. We obtain the power to serve their requirements from our generating facilities and purchases of power from other power suppliers.

We are subject to changes in fuel costs for our generating facilities, which could increase the cost of generating power. We are also exposed to changes in purchased power costs. Increases in fuel costs and purchased power costs increase the cost to our member distribution cooperatives. Factors that could influence fuel and purchased power costs include:

- weather;
- supply and demand;
- the availability of competitively priced alternative energy sources;
- constraints related to the transportation of fuels;
- price competition among fuels used to produce electricity, including natural gas, coal, and oil;
- availability and efficient operation of our generating facilities;
- transmission constraints;
- the impact of implementation of new technologies in the power industry, such as energy storage technologies;
- federal, state, and local energy and environmental regulation and legislation, including increased regulation of the extraction of natural gas and coal; and
- war, acts and threats of terrorism, sabotage, natural disasters, pandemics, and other catastrophic events.

Historically, our power supply strategy had relied substantially on purchases of energy from other power suppliers. However, in 2018, our Wildcat Point generation facility achieved commercial operation, which increased our purchases of fuel and reduced our reliance on purchases of energy. In 2019, we purchased approximately 43.7% of our energy resources. These purchases consisted of a combination of purchases under physically-delivered forward contracts and purchases of energy in the spot market. Our reliance on purchases of energy from other suppliers will continue in the future. Our reliance on energy purchases could also increase because the operation of our generating facilities is subject to many risks, including changes in their dispatch, shutdown, or breakdown or failure of equipment.

Purchasing power helps us mitigate high fixed costs related to the ownership of generating facilities but exposes us to significant market price risk because energy prices can fluctuate substantially. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we utilize our judgment and assumptions in our models. Our judgment and assumptions relate to factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas, used to generate electricity. Our models cannot predict what will actually occur and our results may vary materially from what our models forecast, which may in turn impact our resulting costs to our members. Our models become less reliable the further into the future that the estimates are made. Although we have developed strategies to attempt to meet our power requirements in an economical manner and we have implemented a hedging strategy to limit our exposure to variability in the market, we still may purchase energy at a price which is higher than other utilities' costs of generating energy or future market prices of energy. For further discussion of our market price risk, see "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A.

Technological advancements and other changes impacting power requirements of our member distribution cooperatives' customers may reduce demand for power from us.

Technological advancements are occurring in the electric industry, including advancements related to self-generation and distributed energy technologies. Distributed energy technologies include fuel cells, batteries, micro turbines, wind turbines and solar cells. The increased adoption of these technologies and a greater degree of the adoption of energy efficiency technology and conservation by our member distribution cooperatives' customers, along with the impact of regional economic conditions, could reduce our member distribution cooperatives' demand for power from us and cause our long-term load expectations to be materially less than planned.

Our generating assets may be impacted by regulatory changes in PJM.

PJM, an RTO, coordinates and establishes policies for the generation, purchase, and sale of capacity and energy in the control areas of its members. We are a member of PJM and we participate in its energy, capacity, and transmission services markets to serve our member distribution cooperatives. All of our member distribution cooperatives' service territories are located in PJM. As a member of PJM, we are subject to the operations of PJM, and our generating facilities are under dispatch control of PJM. Material regulatory changes by FERC impacting the operations of PJM, including the design of the wholesale markets or its interpretation of market rules, or changes to pricing rules or rules involving revenue calculations, could adversely impact our costs or operations.

Environmental regulation may limit our operations or increase our costs or both.

We are required to comply with numerous federal, state, and local laws and regulations, relating to the protection of the environment. We believe that we have obtained all material environmental approvals currently required to own and operate our existing facilities or that necessary approvals have been applied for and will be issued in a timely manner. We may incur significant additional costs because of compliance with these requirements. Failure to comply with environmental laws and regulations could have a material effect on us, including potential civil or criminal liability and the imposition of fines or expenditures of funds to bring our facilities into compliance. Delay in obtaining, or failure to obtain and maintain in effect, any environmental approvals, or the delay or failure to satisfy any applicable environmental regulatory requirements related to the operation of our existing facilities or the sale of energy from these facilities could result in significant additional cost to us.

On September 6, 2019, ACE, a replacement rule for the Clean Power Plan, became effective and requires that each state implement plans to meet state-specific carbon emissions reductions no later than July 8, 2022. We have ownership interests in generating facilities in Virginia and Maryland and are exposed to the impact of inconsistent standards between states as well as the uncertainty of the implementation plans. We are closely monitoring the rulemaking related to ACE, and we currently cannot predict the impact of ACE on our existing facilities due to the uncertainties and complexities of the regulations.

In March of 2020, the Virginia General Assembly passed legislation, yet to be signed by the governor, authorizing Virginia to join RGGI in 2021 pursuant to the 2019 regulation that established an emission limitation program to reduce CO_2 from electric power facilities. This regulation could result in increased costs to generate power in Virginia. See "Item 1 Business—Regulation—Virginia CO_2 Regulation."

We cannot predict the cost or the effect of any future environmental legislation or regulation. New environmental laws or regulations, the revision or reinterpretation of existing environmental laws or regulations, or penalties imposed for non-compliance with existing environmental laws or regulations may require us to incur additional expenses and could have a material adverse effect on the cost of power we supply our member distribution cooperatives. See "Regulation—Environmental" in Item 1.

We are subject to risks associated with owning an interest in a nuclear generating facility.

We have an 11.6% undivided ownership interest in North Anna, which provided approximately 14.2% of our energy requirements in 2019. Ownership of an interest in a nuclear generating facility involves risks, including:

- potential liabilities relating to harmful effects on the environment and human health resulting from the operation of the facility and the storage, handling, and disposal of radioactive materials;
- significant capital expenditures relating to maintenance, operation, and repair of the facility, including repairs required by the NRC;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with operation of the facility;
- liability for damages resulting from nuclear incidents at facilities owned by others pursuant to the Price-Anderson Act of 1988, which can result in retroactive nuclear insurance premiums; and
- uncertainties regarding the technological and financial aspects of decommissioning a nuclear plant at the end of its licensed life.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of North Anna. If the facility is not in compliance, the NRC may impose fines or shut down the units until compliance is achieved, or both depending upon its assessment of the situation. Revised safety requirements issued by the NRC have, in the past, necessitated substantial capital expenditures at other nuclear generating facilities. North Anna's operating and safety procedures may be subject to additional federal or state regulatory scrutiny as a result of worldwide events related to nuclear facilities. In addition, if a serious nuclear incident at North Anna did occur, it could have a material but presently indeterminable adverse effect on our operations or financial condition. Further, any unexpected shut down at North Anna as a result of regulatory non-compliance or unexpected maintenance will require us to purchase replacement energy.

We may have operational deficiencies or catastrophic events related to our generating and transmission facilities.

The operation of our generating or transmission facilities involves risks, including the breakdown or failure of power generation equipment, transmission lines, pipes or other equipment or processes, fuel supply delivery, and performance below expected levels of output or efficiency. The occurrence of any of these events could result in:

- substantial charges assessed by PJM as a result of the expectation that generating facilities would be available if called upon to be dispatched;
- significant additional capital expenditures to repair or replace the affected facilities; or
- the purchase of potentially more costly replacement power on the open market.

If we are unable to protect our information systems against service interruption, misappropriation of data, or breaches of security, our operations could be disrupted and our reputation may be damaged.

We operate in a highly regulated industry that requires the continued operation of advanced information technology systems and network infrastructure. We rely on networks, information systems, and other technology, including the internet and third-party hosted servers, to support a variety of business processes and activities. Cyber security incidents could compromise our information related to our generating facilities and could adversely affect our ability to operate or manage our facilities effectively. We also use third-party vendors to electronically process certain of our business transactions. Information systems, both ours and those of third-party information processors, are vulnerable to cyber security breach. Our generating facilities and information technology systems, or those of Virginia Power, the co-owner of North Anna and Clover, could be directly or indirectly affected by deliberate or unintentional cyber incidents. These incidents may be caused by failures during routine operations such as system upgrades or user errors, as well as network or hardware failures, malicious or disruptive software, computer hackers, rogue employees or contractors, cyber-attacks by criminal groups or activist organizations, geopolitical events, natural disasters, failures or impairments of telecommunications networks, or other catastrophic events. In addition, such incidents could result in unauthorized disclosure of material confidential information, including personal information or sensitive business information.

If our technology systems are breached or otherwise fail, we may be unable to fulfill critical business functions, including the operation of our generating facilities and our ability to effectively maintain certain internal controls over financial reporting. Further, our generating facilities rely on an integrated transmission system, a disruption of which could negatively impact our ability to deliver power to our member distribution cooperatives. A major cyber incident could result in significant business disruption and expense to repair security breaches or system damage and could lead to litigation, regulatory action, including penalties or fines, and an adverse effect on our reputation. We also may have future compliance obligations related to new mandatory and enforceable NERC reliability standards which address the impacts of geomagnetic disturbances and other physical security risks to the reliable operation of the bulk power system.

Counterparties under power purchase and natural gas arrangements may fail to perform their obligations to us.

Because we rely substantially on the purchase of energy and natural gas from other suppliers, we are exposed to the risk that counterparties will default in performance of their obligations to us. On an on-going basis, we analyze and monitor the default risks of counterparties and other credit issues related to these purchases, and we may require our counterparties to post collateral with us; however, defaults may still occur. Defaults may take the form of failure to physically deliver the purchased energy or natural gas. If a default occurs, we may be forced to enter into alternative contractual arrangements or purchase energy or natural gas in the forward or spot markets at then-current market prices that may exceed the prices previously agreed upon with the defaulting counterparty.

The use of hedging instruments could impact our liquidity.

We use various hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. These hedging instruments generally include collateral requirements that require us to deposit funds or post letters of credit with counterparties when their credit exposure to us is in excess of agreed upon credit limits. When commodity prices decrease to levels below the levels where we have hedged future costs, we may be required to use a material portion of our cash or revolving credit facility to cover these collateral requirements.

Adverse changes in our credit ratings may require us to provide credit support for some of our obligations and could negatively impact our liquidity and our ability to access capital.

S&P, Moody's, and Fitch currently rate our outstanding obligations issued under our Indenture at "A+," "A2," and "A," respectively. Additionally, we have an issuer credit rating of "A+" from S&P, and an implied senior unsecured rating of "A" from Fitch. If these agencies were to downgrade our ratings, particularly below investment grade, we may be required to deposit funds or post letters of credit related to our power purchase arrangements, which may reduce our available liquidity and impact our access to future liquidity resources. To the extent that we would have to provide additional credit support as a result of a downgrade in our credit ratings, our ability to access additional credit may be limited and our liquidity may be materially impaired. Also, we may be required to pay higher interest rates on our revolving credit facility and financings that we may need to undertake in the future, and our potential pool of investors and funding sources could decrease.

War, acts and threats of terrorism, sabotage, natural disasters, pandemics, and other catastrophic events could adversely affect our operations.

We cannot predict the impact that any future terrorist attack, sabotage, natural disaster, or pandemic may have on the energy industry in general, or on our business in particular. Infrastructure facilities, such as electric generating, transmission, and distribution facilities, and RTOs, could be direct targets of, or indirect casualties of, an act of terror or sabotage. The physical compromise of our facilities could adversely affect our ability to operate or manage our facilities effectively. Additionally, any military strikes or sustained military campaign may affect the operation of our facilities in unpredictable ways, such as changes in financial markets, and disruptions of fuel supplies and energy markets. Instability in financial markets as a result of war, terrorism, sabotage, natural disasters, pandemics, credit crises, recession, or other factors could have a significant negative effect on the U.S. economy, affect the availability or delivery of parts or materials that we need to operate our business, or increase the cost of financing and insurance coverage, which could negatively impact our results of operations and financial condition.

Poor market performance will affect the asset values in our nuclear decommissioning trust and our defined benefit retirement plans, which may increase our costs.

We are required to maintain a funded trust to satisfy our future obligation to decommission North Anna. A decline in the market value of those assets due to poor investment performance or other factors may increase our funding requirements for these obligations which may increase our costs.

We participate in the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan. The cost of these plans is funded by our payments to NRECA. Poor performance of investments in these benefit plans may increase our costs to make up our allocable portion of any underfunding.

Failure to comply with regulatory reliability standards, and other regulatory requirements could subject us to substantial monetary penalties.

As a result of EPACT, owners, operators, and users of bulk electric systems, including ODEC, are subject to mandatory reliability standards enacted by NERC and its regional entities, and enforced by FERC. We must follow these standards, which are in place to require that proper functions are performed to ensure the reliability of the bulk power system. Although the standards are developed by the NERC Standards Committee, which includes representatives of various electric energy sectors, and must be just and reasonable, the standards are legally binding and compliance may require increased capital expenditures and costs to provide electricity to our member distribution cooperatives under our wholesale power contracts. If we are found to be in non-compliance with any mandatory reliability standards we could be subject to sanctions, including potentially substantial monetary penalties. New, revised or reinterpreted laws or regulations related to reliability standards or participation in wholesale power markets could also result in substantial monetary penalties if ODEC is found to have violated or failed to comply with applicable standards, laws, and regulations.

Potential changes in accounting practices may adversely affect our financial results.

We cannot predict the impact that future changes in accounting standards or practices may have on public companies in general, the energy industry, or our operations specifically. New accounting standards could be issued that could change the way we record revenues, expenses, assets, and liabilities. These changes in accounting standards could adversely affect our reported earnings or could increase reported liabilities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

Our principal properties consist of our interest in five electric generating facilities, additional distributed generation facilities across our member distribution cooperatives' service territories, and a limited amount of transmission facilities. Substantially all of our physical properties are subject to the lien of our Indenture. Our generating facilities consist of the following:

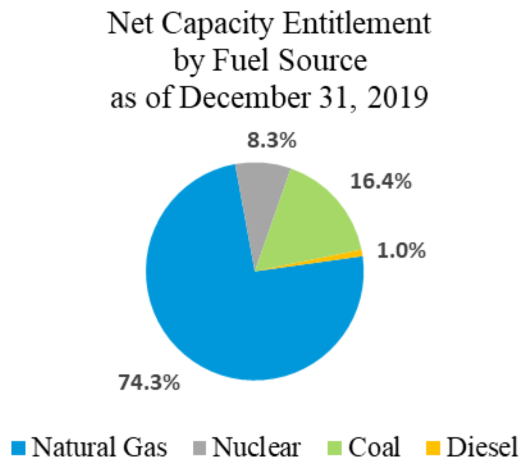
Generating Facility	Ownership Interest	Location	Primary Fuel	Commercial Operation Date	Net Capacity Entitlement [1]
Wildcat Point	100%	Cecil County, Maryland	Natural Gas	04/2018	973 MW
North Anna	11.6%	Louisa County, Virginia	Nuclear	Unit 1 – 06/1978 [2]	110 MW
				Unit 2 – 12/1980 [2]	110 MW
					220 MW
Clover	50%	Halifax County, Virginia	Coal	Unit 1 – 10/1995	220 MW
				Unit 2 – 03/1996	218 MW
					438 MW
Louisa	100%	Louisa County, Virginia	Natural Gas [3]	06/2003	504 MW
Marsh Run	100%	Fauquier County, Virginia	Natural Gas [3]	09/2004	504 MW
Distributed Generation	100%	Multiple	Diesel	07/2002	20 MW
				05/2016	6 MW
					26 MW
				Total	2,665 MW

(1) Represents the projected maximum dependable capacity in summer conditions for Wildcat Point. Represents an approximation of our entitlement to the maximum dependable capacity in summer conditions for North Anna and Clover. Represents a nominal average of summer and winter capacities for Louisa and Marsh Run.

(2) We purchased our 11.6% undivided ownership interest in North Anna in December 1983.

(3) The units at this facility also operate on No. 2 distillate fuel oil as an alternate fuel source.

Generating Facilities by Primary Fuel



Wildcat Point

Wildcat Point is a combined-cycle generation facility that consists of two combustion turbines, two heat recovery steam generators, and one steam turbine generator. We are responsible for the operation and maintenance of Wildcat Point and we supply all services, goods, and materials required to operate and maintain the facility, including arranging for the transportation and supply of the natural gas required by the facility.

North Anna

The NRC has granted operating licenses for North Anna Unit 1 and Unit 2 that extend through April 1, 2038, and August 21, 2040, respectively. Virginia Power, the co-owner of North Anna, has announced its intention to apply for a 20-year operating license extension for North Anna. Virginia Power is responsible for operating and procuring nuclear fuel for North Anna. See "Business—Power Supply Resources—Fuel Supply—Nuclear" in Item 1. We are entitled to 11.6% of the power generated by North Anna. We are responsible for and must fund 11.6% of all post-acquisition date additions and operating costs associated with North Anna, as well as a pro-rata portion of Virginia Power's administrative and general expenses directly attributable to North Anna. In addition, we separately fund our pro-rata portion of the decommissioning costs of North Anna. ODEC and Virginia Power also bear pro-rata any liability arising from ownership of North Anna, except for liabilities resulting from the gross negligence of the other.

Clover

Virginia Power, the co-owner of Clover, is responsible for operating, and procuring and arranging for the transportation of the fuel required to operate Clover. See "Business—Power Supply Resources—Fuel Supply—Coal" in Item 1. ODEC and Virginia Power are each entitled to half of the power generated by Clover. We are responsible for and must fund half of all additions and operating costs associated with Clover, as well as half of Virginia Power's administrative and general expenses directly attributable to Clover.

Combustion Turbine Facilities

Louisa

Louisa consists of five combustion turbines. We are responsible for the operation and maintenance of Louisa and we supply all services, goods, and materials required to operate and maintain the facility, including arranging for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Marsh Run

Marsh Run consists of three combustion turbines. We are responsible for the operation and maintenance of Marsh Run and we supply all services, goods, and materials required to operate and maintain the facility, including arranging for the transportation and supply of the natural gas and No. 2 distillate fuel oil required by the facility.

Distributed Generation Facilities

We have six distributed generation facilities in our member distribution cooperatives' service territories primarily to enhance our system's reliability. We have 14 MW and 12 MW of distributed generation to serve our member distribution cooperatives in the Virginia mainland territory and the Delmarva Peninsula territory, respectively.

Transmission

We own approximately 110 miles of transmission lines on the Virginia portion of the Delmarva Peninsula. As a transmission owner in PJM, we have relinquished dispatch control of these transmission facilities to PJM and contracted with third parties to operate and maintain them.

Indenture

The Indenture grants a lien on substantially all of our real property and tangible personal property and some of our intangible personal property in favor of the trustee, with limited exceptions. The obligations outstanding under the Indenture, including all of our long-term indebtedness, are secured equally and ratably by the trust estate under the Indenture.

ITEM 3. LEGAL PROCEEDINGS

Recovery of Costs from PJM

In 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 facilities. In 2015, FERC denied our petition, we filed a request for rehearing, and FERC issued an order granting rehearing for the limited purpose of FERC's further consideration of the matter. In 2016, FERC denied our request for rehearing and, on June 15, 2018, the United States Court of Appeals for the District of Columbia Circuit denied our Petition for Review. We continue to pursue recovery as a separate breach of an oral contract claim in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. PJM removed the matter to United States District Court for the Eastern District of Virginia in July of 2019 and filed a motion to dismiss. In 2019, we filed a motion to remand the matter to state court. We continue to await the ruling on both motions. We have not recorded a receivable related to this matter.

Wildcat Point

In 2017, WOPC, a joint venture between PCL Industrial Construction Company and Sargent & Lundy, L.L.C., as EPC contractor, made a claim against Alstom and us for recovery of additional amounts under the EPC contract for Wildcat Point. Additionally, in 2017, we filed a complaint alleging that WOPC breached the EPC contract. Subsequently, 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, be consolidated. On January 9, 2020, ODEC and WOPC settled their dispute and ODEC was dismissed as a party from the case.

Other

Other than the issues discussed above and certain other legal proceedings arising out of the ordinary course of business that 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 4. MINE SAFETY DISCLOSURES

Not Applicable

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Not Applicable

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data below present selected historical information relating to our financial condition and results of operations. The financial data for the five years ended December 31, 2019, is derived from our audited consolidated financial statements. You should read the information contained in this table together with our consolidated financial statements, the related notes to the consolidated financial statements, and the discussion of this information in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7.

	Year Ended December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
	(in thousands, except ratios)				
Statement of Operations Data					
Operating Revenues	$ 932,682	$ 932,568	$ 753,107	$ 877,871	$ 1,020,028
Operating Margin	72,796	63,356	39,974	45,192	48,953
Net Margin attributable to ODEC	16,954	13,279	26,627	17,637	11,879
Margins for Interest Ratio	1.29	1.26	2.13	1.67	1.27

	As of December 31,				
	2019	**2018**	**2017**	**2016**	**2015**
	(in thousands, except ratios)				
Balance Sheet Data					
Net Electric Plant	$1,657,088	$1,639,896	$1,703,291	$1,650,918	$1,457,573
Total Investments	216,488	182,017	297,502	270,268	254,624
Other Assets	295,668	244,988	208,369	208,930	289,402
Total Assets	$2,169,244	$2,066,901	$2,209,162	$2,130,116	$2,001,599
Patronage capital [(1)]	$ 441,311	$ 428,663	$ 415,384	$ 402,857	$ 390,976
Non-controlling interest	5,846	5,776	5,744	5,725	5,704
Long-term debt [(2)]	1,117,867	1,158,141	1,198,396	990,083	1,017,926
Revolving credit facility	67,200	—	43,400	152,000	—
Long-term debt due within one year	40,792	40,792	40,792	28,292	28,292
Total Capitalization and Short-term Debt	$1,673,016	$1,633,372	$1,703,716	$1,578,957	$1,442,898
Equity Ratio [(3)]	26.5%	26.3%	24.5%	25.6%	27.2%

(1) For 2019, patronage capital includes a $4.3 million equity contribution and a $4.3 million patronage capital retirement. For 2017, patronage capital includes a $14.1 million equity contribution and a $14.1 million patronage capital retirement. For 2016, patronage capital includes a $5.8 million equity contribution and a $5.8 million patronage capital retirement.

(2) Includes debt issuance costs as a direct reduction to long-term debt.

(3) Equity ratio equals patronage capital divided by the sum of our long-term debt, revolving credit facility, long-term debt due within one year, and patronage capital.

Our Indenture obligates us to establish and collect rates for service to our member distribution cooperatives, which are reasonably expected to yield a margins for interest ratio for each fiscal year equal to at least 1.10, subject to any necessary regulatory or judicial approvals. The Indenture requires that these amounts, together with other moneys available to us, provide us moneys sufficient to remain in compliance with our obligations under the Indenture. We calculate the margins for interest ratio by dividing our margins for interest by our interest charges.

Margins for interest under the Indenture equal:

- our net margins;
- plus revenues that are subject to refund at a later date, which were deducted in the determination of net margins;
- plus non-recurring charges that may have been deducted in determining net margins;
- plus total interest charges (calculated as described below);
- plus income tax accruals imposed on income after deduction of total interest for the applicable period.

In calculating margins for interest under the Indenture, we factor in any item of net margin, loss, income, gain, earnings or profits of any of our affiliates or subsidiaries, only if we have received those amounts as a dividend or other distribution from the affiliate or subsidiary, or if we have made a contribution to, or payment under a guarantee or like agreement for an obligation of, the affiliate or subsidiary. Any amounts that we are required to refund in subsequent years do not reduce margins for interest as calculated under the Indenture for the year the refund is paid.

Interest charges under the Indenture equal our total interest charges (other than capitalized interest) related to (1) all obligations under the Indenture, (2) indebtedness secured by a lien equal or prior to the lien of the Indenture, and (3) obligations secured by liens created or assumed in connection with a tax-exempt financing for the acquisition or construction of property used by us, in each case including amortization of debt discount and expense or premium.

ITEM 7. 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 regulations, 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.

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 energy purchases. We also supply the transmission services necessary to deliver this power to our member distribution cooperatives.

Our results for the year ended December 31, 2019, were primarily impacted by the operational availability and PJM's economic dispatch of our generating facilities, commercial operation of Wildcat Point, PJM charges for network transmission services, and the amortization of the gain on the sale of Rock Springs and related assets.

- Generation from our owned facilities decreased 9.3%, as compared to the same period in 2018. Generation from Wildcat Point, which achieved commercial operation and was available for dispatch by PJM on April 17, 2018, increased 8.8%, whereas generation from Clover decreased 55.5% due to scheduled outages and PJM's economic dispatch of the facility, and generation from North Anna decreased 4.2% due to scheduled outages. Generation from our combustion turbine facilities decreased 9.0%, primarily due to the sale of Rock Springs and related assets on September 14, 2018. The decrease in total generation and scheduled outages contributed to the $14.2 million, or 7.6%, decrease in fuel expense.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased 16.4%. Purchased energy expense decreased $79.8 million, or 21.4%, due to the 16.2% decrease in the average cost of purchased energy and the 6.2% decrease in the volume of purchased energy. The decrease in purchased energy expense was partially offset by the $14.5 million, or 61.0%, increase in capacity-related purchased power expense.
- Transmission expense increased $24.4 million, or 18.0%, due to PJM charges for network transmission services.
- Amortization of the gain on the sale of Rock Springs and related assets reduced our demand costs by $37.7 million. See "Factors Affecting Results—Generating Facilities—Sale of Rock Springs Combustion Turbine Facility."

As a result of these and other factors, demand revenues from our member distribution cooperatives increased $50.2 million, or 13.3%, and energy revenues from our member distribution cooperatives decreased $17.2 million, or 3.5%. Additionally, deferred energy expense changed by $44.9 million, from a $22.4 million under-collection in 2018 to a $22.5 million over-collection in 2019.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of ODEC and TEC. See "Note 1—Summary of Significant Accounting Policies—General" in the Notes to the Consolidated Financial Statements in Item 8.

Critical Accounting Policies

The preparation of our financial statements in conformity with generally accepted accounting principles requires that our management make estimates and assumptions that affect the amounts reported in our financial statements. We base these estimates and assumptions on information available as of the date of the financial statements. We consider the following accounting policies to be critical accounting policies due to the estimation involved in each.

Accounting for Regulated Operations

We are a rate-regulated entity and, as a result, are subject to the accounting requirements of Accounting for Regulated Operations. In accordance with Accounting for Regulated Operations, certain of our revenues and expenses can be deferred at the discretion of our board of directors, which has budgetary and rate setting authority, if it is probable that these amounts will be collected or returned through our formula rate in future periods. Regulatory assets represent costs that we expect to collect from our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. Regulatory liabilities represent probable future reductions in our revenues associated with amounts that we expect to return to our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. See "Factors Affecting Results—Formula Rate" below. Regulatory assets are generally included in deferred charges and other assets and regulatory liabilities are generally included in deferred credits and other liabilities. Deferred energy, which can be either a regulatory asset or regulatory liability, is included in current assets or current liabilities, respectively. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses, respectively, concurrent with their recovery through rates.

Deferred Energy

In accordance with Accounting for Regulated Operations, we use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Deferred energy on our Consolidated Statements of Revenues, Expenses, and Patronage Capital represents the difference between energy revenues, which are based upon energy rates approved by our board, and energy expenses, which are based upon actual energy costs incurred. The deferred energy balance on our Consolidated Balance Sheet represents the net accumulation of any under- or over-collection of energy costs. Under-collected energy costs appear as an asset and will be collected from our member distribution cooperatives in subsequent periods through our formula rate. Conversely, over-collected energy costs appear as a liability and will be returned to our member distribution cooperatives in subsequent periods through our formula rate.

Margin Stabilization

Margin Stabilization allows us to review our actual demand-related costs of service and demand revenues 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 collect and return amounts utilizing Margin Stabilization. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, generally in the succeeding calendar year. We adjust operating revenues and accounts receivable–members or accounts payable–members, as appropriate, to reflect these adjustments. These adjustments are treated as due, owed, incurred, and accrued for the year to which the adjustment relates. See "Factors Affecting Results—Formula Rate" below. The following table details the reduction in revenues utilizing Margin Stabilization for the past three years:

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Margin Stabilization adjustment	$7,175	$15,312	$34,144

Accounting for Asset Retirement and Environmental Obligations

Accounting for Asset Retirement and Environmental Obligations 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. In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Asset retirement obligations currently reported on our Consolidated Balance Sheet were measured during a period of historically low interest rates. The impact on measurements of new asset retirement obligations using different rates in the future may be significant.

A significant portion of our asset retirement obligations relates to our share of the future costs to decommission North Anna. As of December 31, 2019 and 2018, our share of North Anna's nuclear decommissioning asset retirement obligation totaled $152.4 million, or 87.8% of total asset retirement obligations, and $110.2 million, or 84.5% of our total asset retirement obligations, respectively. Approximately every four years, a new decommissioning study for North Anna is performed by third-party experts. The third-party experts provide us with periodic site-specific "base year" cost studies in order to estimate the nature, cost, and timing of planned decommissioning activities for North Anna. These cost studies are based on relevant information available at the time they are performed, however, estimates of future cash flows for extended periods are by nature highly uncertain and may vary significantly from actual results. In addition, these estimates are dependent on subjective factors, including the selection of cost escalation rates, which we consider to be a critical assumption. Our current estimate is based on a study that was performed in 2019 and adopted effective December 31, 2019, which resulted in an increase in our asset retirement obligation of $37.6 million. We are not aware of any events that have occurred since the 2019 study that would materially impact our estimate. See "Note 3—Accounting for Asset Retirement and Environmental Obligations" in the Notes to Consolidated Financial Statements in Item 8.

We determine cost escalation rates, which represent projected cost increases over time, due to both general inflation and increases in the cost of specific decommissioning activities. The following table details the weighted average cost escalation rates used by the study:

Year Study Performed	Weighted Average Cost Escalation Rate
2002	3.27%
2005	2.42
2009	2.30
2014	2.04
2019	1.85

The weighted average cost escalation rate was applied if the cash flows increased as compared to the previous study. The original weighted average cost escalation rate was applied if the cash flows decreased as compared to the previous study. The use of alternative rates would have been material to the liabilities recognized. For example, had we increased the cost escalation rates by 0.5%, the amount recognized as of December 31, 2019, for our asset retirement obligations related to nuclear decommissioning would have been $41.9 million higher.

Accounting for Derivatives and Hedging

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of these forward purchase derivative contracts qualify for the normal purchases/normal sales accounting exception under Accounting for Derivatives and Hedging. As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the physically-delivered forward contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for our facilities which utilize natural gas. These derivatives do not qualify for the normal purchases/normal sales accounting exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we defer all unrealized gains and losses on a net basis as a regulatory liability or regulatory asset, respectively, in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense on our Consolidated Statements of Revenues, Expenses, and Patronage Capital as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported at fair value on our Consolidated Balance Sheet in the regulatory assets or regulatory liabilities account, and deferred charges and other assets–other or deferred credits and other liabilities–other. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications.

Factors Affecting Results

Margins

We operate on a not-for-profit basis and, accordingly, seek to generate revenues sufficient to recover our cost of service and produce margins sufficient to establish reasonable reserves, meet financial coverage requirements, and accumulate additional equity approved by our board of directors. Revenues in excess of expenses in any year are designated as net margin attributable to ODEC on our Consolidated Statements of Revenues, Expenses, and Patronage Capital. We designate retained net margins attributable to ODEC on our Consolidated Balance Sheet as patronage capital, which we assign to each of our members on the basis of its class of membership and business with us.

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 (margin requirement); 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 natural gas, nuclear, and coal 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 capacity costs under power purchase contracts with third parties, transmission costs, administrative and general expenses, depreciation expense, interest expense, margin requirement, 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 requirement, 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. See "Critical Accounting Policies—Margin Stabilization" above.

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.

Recognition of Revenue

Our operating revenues reflect the actual demand-related costs we incurred plus the energy costs that we collected. Estimated demand-related costs are collected during the period through the demand components of our formula rate. In accordance with Margin Stabilization, these costs, as well as operating revenues, are adjusted at the end of each reporting period to reflect actual demand-related costs incurred during that period. See "Critical Accounting Policies—Margin Stabilization" above. Estimated energy costs are collected during the period through the energy components of our formula rate. Operating revenues are not adjusted at the end of each reporting period to reflect actual energy costs incurred during that period. The difference between actual energy costs incurred and energy costs collected during each period is recorded as deferred energy expense, which may be a positive or negative number. See "Critical Accounting Policies—Deferred Energy" above.

We bill energy to each of our member and non-member customers based on the total MWh delivered to them each month. We bill demand costs through three separate rates: a transmission service rate, an RTO capacity service rate, and a remaining owned capacity service rate. See "—Formula Rate" above. The transmission service rate is billed to each of our member distribution cooperatives based on its contribution to the single zonal coincident peak (the hour of the month the need for energy is highest) for the prior year within each of the PJM transmission zones. The RTO capacity service rate is billed to each of our member distribution cooperatives based on its contribution to the average of the five hourly PJM coincident peaks in the prior year, subject to add-backs for participation in PJM demand response programs. The remaining owned capacity service rate is billed to each of our member distribution cooperatives based on its contribution to the monthly zonal coincident peak.

Member Distribution Cooperatives' Requirements for Power

Changes in the number of customers and those customers' requirements for power significantly affect our member distribution cooperatives' requirements for power. Factors affecting our member distribution cooperatives' requirements for power include:

- *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 for energy 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. Heating degree days are calculated as the number of degrees below 60 degrees in a single day. Cooling degree days are calculated as the number of degrees above 65 degrees in a single day. In a single calendar day, it is possible to have multiple heating degree and cooling degree days.

The heating and cooling degree days for the past three years were as follows:

	2019	**2018**	**2017**
Heating degree days	3,228	3,145	2,875
Cooling degree days	1,554	1,492	1,182

- *Economy* – General economic conditions have an impact on the rate of growth of our member distribution cooperatives' energy requirements.
- *Residential growth* – Residential growth in our member distribution cooperatives' service territories and increases in consumption levels increase the requirements for power.
- *Commercial growth* – The amount, size, and usage of electronics and machinery and the expansion of operations among our member distribution cooperatives' commercial and industrial customers impact the requirements for power.
- *Behind-the-meter (distributed generation) resources* – Growth in the number of consumers who serve all or a portion of their electricity requirements from resources behind-the-meter, such as solar panels or local micro-grids, reduces the requirements for power.

For additional discussion of our member distribution cooperatives' customers, see "Members—Member Distribution Cooperatives—Service Territories and Customers" in Item 1.

Power Supply Resources

In an attempt to provide stable power costs to our member distribution cooperatives, we utilize a combination of our owned generating resources and purchases from the market. We also regularly evaluate options for future power sources, including additional owned generation and power purchase contracts.

Market forces influence the structure and price of new power supply contracts into which we enter. When we enter into long-term power purchase contracts or agree to purchase energy at a date in the future, we rely on models based on our judgment and assumptions of factors such as future demand for power and market prices of energy and the price of commodities, such as natural gas, used to generate electricity. Our actual results may vary from what our models predict, which may in turn impact our resulting costs to our members. Additionally, our models become less reliable the further into the future that the estimates are made. See "Risk Factors" in Item 1A.

In 2019, our generating facilities satisfied approximately 93.1% of our PJM capacity obligation and 56.3% of our energy requirements. We obtained the remainder of our PJM capacity obligation through the PJM RPM capacity auction process and purchased capacity contracts. The energy requirements not met by our owned generating facilities were obtained from multiple suppliers under various long-term and short-term physically-delivered forward power purchase contracts and spot market purchases. See "Business—Power Supply Resources" in Item 1 and "Properties" in Item 2.

PJM

PJM is an RTO that serves all of Delaware and Maryland, and most of Virginia, as well as other areas outside our member distribution cooperatives' service territories. We are a member of PJM and are therefore subject to the operations of PJM. PJM coordinates and establishes policies for the generation, purchase, and sale of capacity and energy in the control areas of its members, including all of the service territories of our member distribution cooperatives. As a result, our generating facilities are under dispatch control of PJM.

PJM balances its participants' power requirements with the power resources available to supply those requirements. Based on this evaluation of supply and demand, PJM schedules and dispatches available generating facilities throughout its region in a manner intended to meet the demand for energy in the most reliable and cost-effective manner. Thus, PJM directs the dispatch of these facilities even though it does not own them. When PJM cannot dispatch the most economical generating facilities due to transmission constraints, PJM will dispatch more expensive generating facilities to meet power requirements. For these reasons, actions by PJM may materially affect our operating results. PJM compensates us for the capacity of our generating facilities made available without regard to whether our generating facilities are dispatched. See "Business—Power Supply Resources—PJM" in Item 1.

We transmit power to our member distribution cooperatives through the transmission facilities subject to PJM operational control. We have agreements with PJM which provide us with access to transmission facilities under PJM's control as necessary to deliver energy to our member distribution cooperatives. We own a limited amount of transmission facilities. See "Properties—Transmission" in Item 2.

Transmission owners within PJM have made significant investments in their transmission systems. Because transmission rates are established to recover the cost of investment plus a return on the investment, PJM's rates for network transmission services have increased significantly in recent years. Our transmission costs are impacted each year by billing determinants, which are based on our usage during the peak hour of the year for each transmission area. See "Results of Operations—Operating Expenses" below.

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 178 MW of demand and associated energy. 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 on Wholesale Power Contracts, see "Business—Members—Member Distribution Cooperatives—Wholesale Power Contracts" in Item 1.

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. See "—PJM" above.

Operational Availability

The operational availability of our owned generating resources for the past three years was as follows:

	Year Ended December 31,		
	2019 [(1)]	2018	2017
Wildcat Point [(2)]	75.6%	84.2%	—%
North Anna	91.3	94.9	95.3
Clover	68.9	78.8	78.8
Louisa	94.5	97.2	93.4
Marsh Run	94.2	95.2	96.8
Rock Springs [(3)]	—	92.0	95.4

(1) Generating facilities operational availabilities were impacted by scheduled outages in 2019.

(2) Wildcat Point achieved commercial operation on April 17, 2018.

(3) Rock Springs and related assets were sold on September 14, 2018.

Capacity Factor

The output of Wildcat Point, North Anna, and Clover for the past three years as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Year Ended December 31,		
	2019	2018	2017
Wildcat Point [(1)] [(2)]	40.7%	51.8%	—%
North Anna [(3)]	92.5	96.5	97.3
Clover [(4)]	17.1	38.8	43.5

(1) Wildcat Point achieved commercial operation on April 17, 2018.

(2) Wildcat Point capacity factors were impacted by scheduled outages in 2019 and PJM's economic dispatch of the facility.

(3) North Anna capacity factors were impacted by scheduled outages in 2019.

(4) Clover capacity factors were impacted by scheduled outages in 2019, 2018, and 2017 and PJM's economic dispatch of the facility.

Each unit at North Anna is scheduled for refueling approximately every 18 months. While only one unit is refueled at a time, this refueling schedule typically results in both units being off-line for refueling during the same calendar year once every three years. During 2019, both units at North Anna were off-line for refueling and during 2018 and 2017, one unit at North Anna was off-line for refueling.

Sale of Rock Springs Combustion Turbine Facility

On September 14, 2018, we sold our interest in Rock Springs and related assets to EPRS for $115 million. Prior to the sale, we and EPRS had each individually owned two natural gas-fired combustion turbine units and a 50% undivided interest in related common facilities at Rock Springs. The transaction resulted in a gain of $42.7 million, which our board of directors approved to defer as a regulatory liability. We amortized $5.0 million of the gain in 2018 and the remaining $37.7 million was amortized in 2019.

Changing Environmental Regulation

We are subject to extensive federal and state regulation regarding environmental matters. This regulation is becoming increasingly stringent through amendments to federal and state statutes and the development of regulations authorized by existing law. Future federal and state legislation and regulations present the potential for even greater obligations to limit the impact on the environment from the operation of our generating and transmission facilities. See “Business—Regulation— Environmental” in Item 1 and “Risk Factors” in Item 1A.

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. See "—Member Distribution Cooperatives' Requirements for Power" above. Our formula rate is based on our cost of service in meeting these requirements. See “—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 purchased power portfolio, 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 by type of purchaser and our energy sales in MWh for the past three years were as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Revenues from sales to:			
Member distribution cooperatives			
Energy revenues	$ 471,767	$ 488,949	$ 412,349
Renewable energy credits	26	16	19
Demand revenues	426,678	376,444	319,208
Total revenues from sales to member distribution cooperatives	898,471	865,409	731,576
Non-members			
Energy revenues	29,483	64,209	16,356
Renewable energy credits	4,672	2,950	5,175
Demand revenues	56	—	—
Total revenues from sales to non-members	34,211	67,159	21,531
Total operating revenues	$ 932,682	$ 932,568	$ 753,107
Energy sales to:		(in MWh)	
Member distribution cooperatives	11,483,669	11,872,158	11,419,738
Non-members	946,311	1,638,715	458,763
Total energy sales	12,429,980	13,510,873	11,878,501
Average cost of energy to member distribution cooperatives (per MWh)	$ 41.08	$ 41.18	$ 36.11
Average total cost to member distribution cooperatives (per MWh)	$ 78.24	$ 72.89	$ 64.06

Member Distribution Cooperatives

In 2019, total revenues from sales to our member distribution cooperatives increased $33.1 million, or 3.8%, as compared to 2018. Demand revenues increased $50.2 million, or 13.3%, primarily due to increases in transmission expense, capacity-related purchased power expense, operations and maintenance expense, interest charges, net, and depreciation and amortization expense, partially offset by the amortization of regulatory asset/(liability), net. Energy revenues decreased $17.2 million, or 3.5%, primarily due to the 3.3% decrease in energy sales in MWh to our member distribution cooperatives.

The following table summarizes the changes to our total energy rate since 2017, which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Rate Change	**% Change**
January 1, 2017	(6.7)
January 1, 2018	11.1
April 1, 2018	3.7
January 1, 2019	(1.3)
January 1, 2020	(16.2)

Operating Expenses

The following is a summary of the components of our operating expenses for the past three years.

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Fuel	$ 172,921	$ 187,118	$ 94,603
Purchased power	332,216	397,589	397,387
Transmission	159,995	135,567	97,302
Deferred energy	22,522	(22,400)	(43,698)
Operations and maintenance	74,647	64,705	48,508
Administrative and general	48,938	45,171	42,182
Depreciation and amortization	68,752	62,503	45,433
Amortization of regulatory asset/(liability), net	(35,056)	(15,853)	18,156
Accretion of asset retirement obligations	5,539	5,319	5,044
Taxes, other than income taxes	9,412	9,493	8,216
Total Operating Expenses	$ 859,886	$ 869,212	$ 713,133

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 fuel expense, the energy portion of our purchased power expense, and the variable portion of operations and maintenance expense. Our demand costs generally are fixed and include the capacity portion of our purchased power expense, transmission 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 investment income, and interest charges, net are components of our demand costs. See “Factors Affecting Results—Formula Rate” above.

Total operating expenses decreased $9.3 million, or 1.1%, for 2019 as compared to 2018, primarily as a result of the decreases in purchased power expense, amortization of regulatory asset/(liability), net, and fuel expense; substantially offset by increases in deferred energy expense and transmission expense.

- Purchased power expense, which includes the cost of purchased energy and capacity, decreased $65.4 million, or 16.4%, due to the $79.8 million, or 21.4%, decrease in purchased energy, partially offset by the $14.5 million, or 61.0%, increase in capacity-related purchased power expense. The average cost of purchased energy decreased 16.2% and the volume of purchased energy decreased 6.2%.
- Amortization of regulatory asset/(liability), net decreased $19.2 million primarily due to the $37.7 million amortization of the gain on the sale of Rock Springs and related assets. In 2018, we amortized $15.0 million of deferred revenue and $5.0 million of the gain on the sale of Rock Springs and related assets.
- Fuel expense decreased $14.2 million, or 7.6%, primarily as a result of the 9.3% decrease in generation from our owned facilities. Generation from Wildcat Point, which achieved commercial operation and was available for dispatch by PJM on April 17, 2018, increased 8.8%, whereas generation from Clover decreased 55.5% due to scheduled outages and PJM’s economic dispatch of the facility, and generation from North Anna decreased 4.2% due to scheduled outages. Generation from our combustion turbine facilities decreased 9.0%, primarily due to the sale of Rock Springs and related assets on September 14, 2018.
- Deferred energy expense, which represents the difference between energy revenues and energy expenses, increased $44.9 million. In 2019 we over-collected $22.5 million and in 2018 we under-collected $22.4 million.
- Transmission expense increased $24.4 million, or 18.0%, due to PJM charges for network transmission services.

Other Items

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 past three years were as follows:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Interest on long-term debt	$ (59,931)	$ (62,032)	$ (59,441)
Interest on revolving credit facility	(802)	(2,083)	(2,384)
Other interest	(2,506)	(2,277)	(809)
Total interest charges	(63,239)	(66,392)	(62,634)
Allowance for borrowed funds used during construction	466	11,170	35,594
Interest charges, net	$ (62,773)	$ (55,222)	$ (27,040)

In 2019, interest charges, net increased $7.6 million as compared to the same period in 2018, due to the $10.7 million decrease in allowance for borrowed funds used during construction (capitalized interest) related to the commencement of the commercial operation of Wildcat Point.

Net Margin Attributable to ODEC

In 2019, net margin attributable to ODEC, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, increased $3.7 million, as a result of the $4.3 million equity contribution in 2019 and the absence of an equity contribution in 2018. See “Factors Affecting Results—Formula Rate” above and "Note 1—Summary of Significant Accounting Policies—Patronage Capital” in the Notes to Consolidated Financial Statements in Item 8.

Discussion of Results of Operations Comparing 2018 to 2017

For discussion of our financial results comparing 2018 to 2017, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations" in Item 7 of our 2018 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 6, 2019.

Financial Condition

The principal changes in our financial condition from December 31, 2018 to December 31, 2019, were caused by increases in revolving credit facility, asset retirement obligations, nuclear decommissioning trust, accounts payable, regulatory liabilities, deferred credits and other liabilities–other, deferred charges and other assets–other, and regulatory assets; and decreases in regulatory liability–deferred gain on sale of asset, accounts payable–members, and deferred energy.

- Revolving credit facility increased $67.2 million due to outstanding borrowings under this facility.
- Asset retirement obligations increased $43.2 million primarily due to the change in our asset retirement obligations related to North Anna. In 2019, a new decommissioning study was performed resulting in an increase to our asset retirement obligation related to North Anna of $37.6 million.
- Nuclear decommissioning trust increased $37.2 million due to the increase in the market value of our investments.
- Accounts payable increased $34.4 million primarily due to increased construction-related payables associated with the settlement of our dispute with WOPC.
- Regulatory liabilities increased $30.2 million primarily due to the increase in the regulatory liability related to the unrealized gain on the North Anna nuclear decommissioning trust.
- Deferred credits and other liabilities–other increased $23.5 million due to decreases in the fair value of our natural gas hedges.
- Deferred charges and other assets–other increased $21.2 million primarily due to additional collateral requirements related to our natural gas hedges.
- Regulatory assets increased $19.7 million primarily due to the deferred net unrealized losses on derivative instruments.
- Regulatory liability–deferral of gain on sale of asset decreased $37.7 million due to the amortization of the gain on the sale of Rock Springs and related assets.
- Accounts payable–members decreased $30.7 million due to the decrease in member prepayments as well as the decrease in the Margin Stabilization adjustment as compared to 2018.
- Deferred energy decreased $22.5 million as a result of the over-collection of our energy costs in 2019. The deferred energy balance was an under-collection of $26.1 million and $3.5 million at December 31, 2018 and 2019, respectively.

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

In 2019, 2018, and 2017, our operating activities provided cash flows of $18.0 million, $58.2 million, and $56.5 million, respectively.

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 through February 28, 2025. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through February 28, 2025. As of December 31, 2019, we had outstanding under this facility, $67.2 million in borrowings at a weighted average interest rate of 2.8% and a $0.5 million letter of credit. We did not have any borrowings outstanding under this facility as of December 31, 2018; however, the interest rate on borrowings would have been 3.5%. As of December 31, 2018, we had a $2.5 million letter of credit outstanding under this facility. As of March 10, 2020, we had outstanding under this facility, $115.0 million in borrowings and a $0.5 million letter of credit.

The syndicated credit agreement contains customary events of default, which, if they occur, would terminate our ability to borrow amounts under this facility and potentially accelerate any outstanding loans under this facility at the election of the lenders. Some of these customary events of default relate to:

- our failure to timely pay any principal and interest due under the credit facility;
- a breach by us of our representations and warranties in the credit agreement or related documents;
- a breach of a covenant contained in the credit agreement, which, in some cases we are given an opportunity to cure and, in certain cases, includes a debt to capitalization financial covenant;
- failure to pay, when due, other indebtedness above a specified amount;
- an unsatisfied judgment above specified amounts;
- bankruptcy or insolvency events relating to us;
- invalidity of the credit agreement and related loan documentation or our assertion of invalidity; and
- a failure by our member distribution cooperatives to pay amounts in excess of an agreed threshold owing to us beyond a specified cure period.

The calculation of the interest on borrowings under the facility currently is based upon LIBOR. The syndicated credit agreement contains a provision that will result in interest rates being based upon a replacement index for LIBOR, if necessary. It is not clear how the interest rate will be calculated using the replacement index. The phase-out of LIBOR is not expected to have a material adverse effect on our cost of borrowing due to the amounts typically outstanding under the syndicated credit agreement. We do not have other loan agreements or financial instruments where the pricing is determined by reference to LIBOR.

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 issuances of debt in the 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.

Capital Expenditures

We regularly forecast our capital expenditures as part of our long-term business planning activities. We review these projections periodically in order to update our calculations to reflect changes in our future plans, construction costs, market factors, and other items affecting our forecasts. Our actual capital expenditures could vary significantly from these projections. The table below summarizes our actual and projected capital expenditures on a cash flow basis, including capitalized interest, for 2017 through 2022:

	Actual Year Ended December 31,			Projected Year Ended December 31,		
	2017	2018	2019	2020	2021	2022
			(in millions)			
Wildcat Point	$ 118.2	$ 31.6	$ 6.0	$ 69.8	$ 1.0	$ 0.7
North Anna nuclear fuel	17.0	8.8	16.9	15.4	6.7	9.7
North Anna	3.5	7.1	2.6	14.6	11.4	19.4
Clover	7.1	11.4	7.4	3.4	1.8	5.1
Transmission	1.8	0.6	0.5	6.2	11.7	23.5
Combustion turbine facilities	4.9	1.1	2.3	1.8	1.2	0.2
Other	1.4	1.0	0.6	0.2	0.2	0.2
Total	$ 153.9	$ 61.6	$ 36.3	$ 111.4	$ 34.0	$ 58.8

Nearly all of our capital expenditures consist of additions to electric plant and equipment. Capital expenditures for Wildcat Point for 2020 include amounts in accounts payable as of December 31, 2019, related to the settlement of our dispute with WOPC and final major equipment payments. Capital expenditures for North Anna include $7.7 million, $7.3 million, and $13.6 million, for 2020, 2021, and 2022, respectively, for costs related to license extension. Capital expenditures for Transmission for 2020, 2021, and 2022 include costs related to transmission facility upgrades in accordance with the PJM planning processes. Capital expenditures for Other include costs related to our administrative and general assets, and distributed generation facilities. We intend to use our cash flow from operations, borrowings under our revolving credit facility, and issuances of debt in the capital markets to fund all of our currently projected capital requirements through 2022.

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. See “Business—Power Supply Resources—Power Purchase Contracts” in Item 1. The following table summarizes our long-term contractual obligations as of December 31, 2019:

	Payments due by Period				
	Total	2020	2021-2022	2023-2024	2025 and Thereafter
			(in millions)		
Long-term debt obligations	$ 2,009.9	$ 95.8	$ 201.5	$ 191.4	$ 1,521.2
Power purchase obligations	134.9	130.5	4.4	—	—
Asset retirement obligations	173.7	—	—	—	173.7
Operating lease obligations	3.4	0.6	1.1	1.1	0.6
Construction obligations	69.8	69.8	—	—	—
Total	$ 2,391.7	$ 296.7	$ 207.0	$ 192.5	$ 1,695.5

We expect to fund these obligations with cash flow from operations, borrowings under our revolving credit facility, and issuances of debt in the capital markets.

Long-term Debt Obligations

As of December 31, 2019, our long-term debt obligations include long-term debt issued privately and to the public under the Indenture. Long-term debt includes both the principal of and interest on long-term debt, and long-term debt due within one year.

Power Purchase Obligations

As part of our power supply strategy, we entered into a number of agreements for the purchase of energy or capacity, or both, in order to meet our member distribution cooperatives' requirements. See "Business—Power Supply Resources—Power Purchase Contracts" in Item 1.

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. The asset retirement obligations are shown at present value. A significant portion of our asset retirement obligations relates to our share of the future costs to decommission North Anna. See "Critical Accounting Policies—Accounting for Asset Retirement and Environmental Obligations" above.

Operating Lease Obligations

Our obligations described above with respect to operating lease obligations relate to our lease for our headquarters building.

Construction Obligations

Our construction obligations include payments related to the settlement of our dispute with WOPC and final major equipment payments.

Significant Contingent Obligations

In addition to these existing contractual obligations, we have significant contingent obligations. These obligations primarily relate to power purchase arrangements and our arrangement with TEC. Some of our power purchase contracts obligate us to provide credit support if our obligations issued under the Indenture are rated below specified thresholds by S&P and Moody's.

Power Purchase and Natural Gas Arrangements

Under the terms of most of our power purchase and natural gas arrangements, we typically agree to provide collateral under certain circumstances and require comparable terms from our counterparties. The collateral we may be required to post with a counterparty, and vice versa, is normally a function of the collateral thresholds we negotiate with a counterparty relative to a range of credit ratings as well as the value of our transaction(s) under a contract with a respective counterparty. As of December 31, 2019, the collateral we had posted with counterparties pursuant to the power purchase and natural gas arrangements we have in place totaled $24.7 million. Typically, collateral thresholds under our contracts are zero once an entity is rated below investment grade by S&P or Moody's (i.e., "BBB-" or "Baa3," respectively). As of December 31, 2019, if our credit ratings had been below investment grade we estimate we would have been obligated to post between $150 million and $200 million of collateral with our counterparties. This calculation is based on power and natural gas prices on December 31, 2019, and delivered power and natural gas for which we had not yet paid. Depending on the difference between the price of power and natural gas under our contracts and the price of power and natural gas in the market at the time of the calculation, this amount could increase or decrease.

Additionally, PJM requires that we provide collateral to support our obligations in connection with certain PJM transactions and as of December 31, 2019, we had posted a $0.5 million letter of credit to PJM. In accordance with its credit policy, PJM subjects each applicant, participant and member of PJM to a credit evaluation. A material change in our financial condition, including the downgrading of our credit rating by any rating agency, could cause PJM to re-evaluate our creditworthiness and require that we provide additional collateral. As of December 31, 2019, if PJM had determined that we needed to provide additional collateral to support our obligations as a result of our creditworthiness, PJM could have asked us to provide up to approximately $14.3 million as collateral.

TEC Guarantees

TEC is considered a variable interest entity for which we are the primary beneficiary, and we have consolidated its results and eliminated all intercompany balances and transactions in consolidation. To facilitate the ability of TEC to sell power in the market, we have agreed to guarantee up to a maximum of $200 million of TEC's delivery and payment obligations associated with its energy trades, if requested. See "Business—Members—TEC" in Item 1. Our agreement to guarantee these obligations continues in effect until we elect to terminate it by providing at least 30 days' prior written notice of termination or until all amounts owed to us by TEC have been paid. Our guarantee of TEC's obligations will enable it to maintain sufficient credit support to meet its delivery and payment obligations associated with its energy trades. As of December 31, 2019, we did not have any guarantees outstanding in support of TEC's obligations.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The operation of our business exposes us to several common market risks, including changes in market prices for power and fuel, and interest rates and equity prices.

Market Price Risk

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. See "Business—Power Supply Resources" in Item 1. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk.

The fair value of the hedging instruments we use to mitigate market price risk is impacted by changes in market prices. As of December 31, 2019, we estimate that the fair value of our purchased power agreements, forward purchases of natural gas, and renewable energy credits held for sale was between $750 million and $800 million. Approximately 37% of the fair value of this portfolio is estimable using observable market prices. The remaining 63% of the fair value of this portfolio is related to less liquid products and the fair values of these products are not directly estimable using observable market prices. In the absence of observable market prices, the valuation of the 63% of this portfolio that relates to less liquid products involves management judgment, the use of estimates, and the underlying assumptions in our portfolio model. As a result, changes in estimates and underlying assumptions or use of alternate valuation methods could affect the estimated fair value of this portfolio. As an example of our portfolio's exposure to market price risk, we estimate that a 10% change in the price of the commodities hedged by the portion of this portfolio with observable market prices would have changed the fair value of this portion of the portfolio by approximately $28.4 million as of December 31, 2019. To the extent all or portions of our portfolio are liquidated above or below our original cost, these gains or losses are factored into the costs billed to our member distribution cooperatives pursuant to our formula rate. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results—Formula Rate" in Item 7.

We have formulated policies and procedures to manage the risks associated with these market price fluctuations. Additionally, we use various hedging instruments, including forwards, futures, financial transmission rights, and options, to manage our power market price risks. ACES assists us in managing our market price risks by:

- maintaining a portfolio model that identifies our power producing resources (including our power purchase contract positions and generating capacity, and fuel supply, transportation, and storage arrangements) and analyzing the optimal use of these resources in light of costs and market risks associated with using these resources;
- modeling our power obligations and assisting us with analyzing alternatives to meet our member distribution cooperatives' power requirements;
- selling excess power as our agent; and
- executing hedge trades to stabilize the cost of fuel requirements, primarily natural gas used to operate our generating facilities.

We also are subject to market price risk relating to purchases of fuel for North Anna and Clover. We manage these risks indirectly through our participation in the management arrangements for these facilities. However, Virginia Power, as operator of these facilities, has the sole authority and responsibility to procure nuclear fuel and coal for North Anna and Clover, respectively.

Virginia Power advises us that it primarily uses long-term contracts to support North Anna's nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices, which are dependent upon the market environment. See "Business—Power Supply Resources—Fuel Supply—Nuclear" in Item 1. In addition, Virginia Power advises us that it uses both long-term contracts and short-term spot agreements to acquire the low sulfur bituminous coal used to fuel Clover. See "Business—Power Supply Resources—Fuel Supply—Coal" in Item 1.

Interest Rate Risk and Equity Price Risk

In 2019, all of our outstanding long-term debt accrued interest at fixed rates.

We maintain a revolving credit facility. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Sources—Revolving Credit Facility" in Item 7. Any amounts we borrow under this facility will accrue interest at a variable rate. As of December 31, 2019, we had outstanding under this facility, $67.2 million in borrowings at a weighted average interest rate of 2.8% and a $0.5 million letter of credit. We estimate that a 10% change in the weighted average interest rate would not have had a material effect on our interest expense as of December 31, 2019.

We accrue decommissioning costs over the expected service life of North Anna and have made periodic deposits to a trust so that the trust balance will cover the estimated costs to decommission North Anna at the time of decommissioning. As of December 31, 2019, $146.6 million, $64.1 million, and $0.4 million were invested in equity securities, debt securities, and cash, respectively. The value of these debt and equity securities will be impacted by changes in interest rates and price fluctuations in equity markets. To minimize adverse changes in the aggregate value of the trust, we actively monitor our portfolio by measuring the performance of the investments against market indices and by maintaining and reviewing established target allocation percentages of assets in the trust to various investment options. We believe the trust's exposure to changes in interest rates and price fluctuations in equity markets will not have a material impact on our financial results.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Management on ODEC's Internal Control over Financial Reporting

Management of Old Dominion Electric Cooperative ("ODEC") has assessed ODEC's internal control over financial reporting as of December 31, 2019, based on criteria for effective internal control over financial reporting described in the "2013 Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that as of December 31, 2019, our system of internal control over financial reporting was properly designed and operating effectively based upon the specified criteria.

Management of ODEC is responsible for establishing and maintaining adequate internal control over financial reporting. ODEC's internal control over financial reporting is comprised of policies, procedures, and reports designed to provide reasonable assurance to ODEC's management and board of directors that the financial reporting and the preparation of the financial statements for external reporting purposes have been handled in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes those policies and procedures that (1) govern records to accurately and fairly reflect the transactions and dispositions of assets of ODEC; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of ODEC are being made only in accordance with authorizations of the management and directors of ODEC; and (3) provide reasonable safeguards against or timely detection of material unauthorized acquisition, use or disposition of ODEC's assets.

Internal controls over financial reporting may not prevent or detect all misstatements. Accordingly, even effective internal control can provide only reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

March 11, 2020

/s/ MARCUS M. HARRIS	/s/ BRYAN S. ROGERS
Marcus M. Harris	Bryan S. Rogers
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

The Board of Directors and Members of Old Dominion Electric Cooperative

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Old Dominion Electric Cooperative (the Cooperative) as of December 31, 2019 and 2018, and the related consolidated statements of revenues, expenses, and patronage capital, and cash flows for each of the three years in the period ended December 31, 2019, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Cooperative at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Cooperative's management. Our responsibility is to express an opinion on the Cooperative's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Cooperative in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Cooperative is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Cooperative's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Cooperative's auditor since 2000.
Richmond, Virginia
March 11, 2020

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
ASSETS:	(in thousands)	
Electric Plant:		
Property, plant, and equipment	$2,531,986	$2,454,568
Less accumulated depreciation	(927,065)	(869,478)
Net Property, plant, and equipment	1,604,921	1,585,090
Nuclear fuel, at amortized cost	20,705	14,694
Construction work in progress	31,462	40,112
Net Electric Plant	1,657,088	1,639,896
Investments:		
Nuclear decommissioning trust	211,108	173,951
Unrestricted investments and other	5,380	8,066
Total Investments	216,488	182,017
Current Assets:		
Cash and cash equivalents	3,469	8,649
Restricted cash and cash equivalents	24,230	14,329
Accounts receivable	12,422	9,310
Accounts receivable–members	101,185	84,410
Fuel, materials, and supplies	62,083	54,494
Deferred energy	3,548	26,069
Prepayments and other	4,702	4,648
Total Current Assets	211,639	201,909
Deferred Charges and Other Assets:		
Regulatory assets	57,742	38,016
Other	26,287	5,063
Total Deferred Charges and Other Assets	84,029	43,079
Total Assets	$2,169,244	$2,066,901
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	$ 441,311	$ 428,663
Non-controlling interest	5,846	5,776
Total Patronage capital and Non-controlling interest	447,157	434,439
Long-term debt	1,117,867	1,158,141
Revolving credit facility	67,200	—
Total Long-term debt and Revolving credit facility	1,185,067	1,158,141
Total Capitalization	1,632,224	1,592,580
Current Liabilities:		
Long-term debt due within one year	40,792	40,792
Accounts payable	147,916	113,477
Accounts payable–members	26,804	57,549
Accrued expenses	5,850	5,997
Regulatory liability–deferral of gain on sale of asset	—	37,723
Total Current Liabilities	221,362	255,538
Deferred Credits and Other Liabilities:		
Asset retirement obligations	173,669	130,488
Regulatory liabilities	117,483	87,300
Other	24,506	995
Total Deferred Credits and Other Liabilities	315,658	218,783
Total Capitalization and Liabilities	$2,169,244	$2,066,901

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

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF REVENUES, EXPENSES, AND PATRONAGE CAPITAL FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017

	2019	2018	2017
		(in thousands)	
Operating Revenues	$ 932,682	$ 932,568	$ 753,107
Operating Expenses:			
Fuel	172,921	187,118	94,603
Purchased power	332,216	397,589	397,387
Transmission	159,995	135,567	97,302
Deferred energy	22,522	(22,400)	(43,698)
Operations and maintenance	74,647	64,705	48,508
Administrative and general	48,938	45,171	42,182
Depreciation and amortization	68,752	62,503	45,433
Amortization of regulatory asset/(liability), net	(35,056)	(15,853)	18,156
Accretion of asset retirement obligations	5,539	5,319	5,044
Taxes, other than income taxes	9,412	9,493	8,216
Total Operating Expenses	859,886	869,212	713,133
Operating Margin	72,796	63,356	39,974
Other income (expense), net	(162)	(3,465)	(3,826)
Investment income	7,188	8,512	12,950
Interest income on North Anna Unit 3 cost recovery	—	141	4,598
Interest charges, net	(62,773)	(55,222)	(27,040)
Income taxes	(25)	(11)	(11)
Net Margin including Non-controlling interest	17,024	13,311	26,645
Non-controlling interest	(70)	(32)	(18)
Net Margin attributable to ODEC	16,954	13,279	26,627
Patronage Capital - Beginning of Period	428,663	415,384	402,857
Patronage Capital - Retirement	(4,306)	—	(14,100)
Patronage Capital - End of Period	$ 441,311	$ 428,663	$ 415,384

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

OLD DOMINION ELECTRIC COOPERATIVE

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 AND 2017

	2019	2018	2017
		(in thousands)	
Operating Activities:			
Net Margin including Non-controlling interest	$ 17,024	$ 13,311	$ 26,645
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	68,752	62,503	45,433
Other non-cash charges	16,951	18,425	18,899
Amortization of lease obligations	—	4,919	6,753
Interest on lease deposits	—	(1,791)	(3,045)
Change in current assets	(27,530)	(2,151)	1,217
Change in deferred energy	22,521	(22,400)	(43,698)
Change in current liabilities	(23,692)	(2,361)	(16,339)
Change in regulatory assets and liabilities	(58,590)	(9,822)	19,683
Change in deferred charges and other assets-other and deferred credits and other liabilities-other	2,575	(2,449)	950
Net Cash Provided by Operating Activities	18,011	58,184	56,498
Investing Activities:			
Purchases of held to maturity securities	(3,115)	(37,844)	(3,723)
Proceeds from sale of held to maturity securities	5,573	145,422	4,024
Purchases of available for sale securities	(53,828)	—	—
Proceeds from sale of available for sale securities	53,828	—	—
Increase in other investments	(5,636)	(7,188)	(12,522)
Electric plant additions	(36,263)	(61,631)	(153,856)
Proceeds from sale of asset	—	115,000	—
Net Cash (Used for) Provided by Investing Activities	(39,441)	153,759	(166,077)
Financing Activities:			
Issuance of long-term debt	—	—	250,000
Debt issuance costs	(257)	(255)	(2,391)
Payment of obligation under long-term lease	—	(108,602)	—
Payments of long-term debt	(40,792)	(40,792)	(28,292)
Draws on revolving credit facility	274,000	372,950	385,400
Repayments on revolving credit facility	(206,800)	(416,350)	(494,000)
Net Cash Provided by (Used for) Financing Activities	26,151	(193,049)	110,717
Net Change in Cash and Cash Equivalents and Restricted Cash and Cash Equivalents	4,721	18,894	1,138
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - Beginning of Period	22,978	4,084	2,946
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - End of Period	$ 27,699	$ 22,978	$ 4,084

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

NOTE 1—Summary of Significant Accounting Policies

General

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative and 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 December 31, 2019 and 2018. The income taxes reported on our Consolidated Statements of Revenues, Expenses, and Patronage Capital relate to the tax provision for TEC, which is a taxable corporation. As TEC is 100% owned by our Class A members, its equity is presented as a non-controlling interest on our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities for which we have significant influence is recorded using the equity method of accounting. We have a power sales contract with TEC under which we may sell to TEC, power that we do not need to meet the needs of our member distribution cooperatives. TEC then sells this power to the market under market-based rate authority granted by FERC. Additionally, we have a separate contract under which we may purchase natural gas from TEC. TEC does not engage in speculative trading.

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 customers located in Virginia, Delaware, and Maryland. Our sole Class B member is TEC. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. Our rates are set periodically by a formula that was accepted for filing by FERC, and are not regulated by the public service commissions of the states in which our member distribution cooperatives operate.

We comply with the Uniform System of Accounts 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 did not have any other comprehensive income for the periods presented.

Electric Plant

Electric plant is stated at original cost when first placed in service. Such cost includes contract work, direct labor and materials, allocable overhead, an allowance for borrowed funds used during construction, and asset retirement costs. Upon the partial sale or retirement of plant assets, the original asset cost and current disposal costs less sale proceeds, if any, are charged or credited to accumulated depreciation. In accordance with industry practice, no profit or loss is recognized in connection with normal sales and retirements of property units.

Maintenance and repair costs are expensed as incurred. Replacements and renewals of items considered to be units of property are capitalized to the property accounts.

Depreciation

We use the group method of depreciation and conduct depreciation studies approximately every five years. Our last depreciation study was performed in 2016 and implemented in 2017. Our depreciation rates were as follows:

Generating Facility	Depreciation Rates		
	2019	2018	2017
Wildcat Point [(1)]	3.1%	3.1%	—%
North Anna	3.3	3.3	3.3
Clover	1.9	1.9	1.9
Louisa	3.1	3.1	3.1
Marsh Run	3.0	3.0	3.0
Rock Springs [(2)]	—	3.1	3.1

(1) Wildcat Point achieved commercial operation on April 17, 2018.

(2) Rock Springs and related assets were sold on September 14, 2018.

Nuclear Fuel

Nuclear fuel is amortized on a unit of production basis sufficient to fully amortize the cost of fuel over its estimated service life and is recorded in fuel expense.

Virginia Power, as operating agent of North Anna, has the sole authority and responsibility to procure nuclear fuel for the facility. Virginia Power advises us that it primarily uses long-term contracts to support North Anna's nuclear fuel requirements and that worldwide market conditions are continuously evaluated to ensure a range of supply options at reasonable prices, which are dependent upon the market environment. We are not a direct party to any of these procurement contracts and we do not control their terms or duration. Virginia Power advises us that current agreements, inventories, and spot market availability are expected to support North Anna's current and planned fuel supply needs for the near term and that additional fuel is purchased as required to attempt to ensure optimal cost and inventory levels.

Under the Nuclear Waste Policy Act of 1982, the DOE is required to provide for the permanent disposal of spent nuclear fuel produced by nuclear facilities, such as North Anna, in accordance with contracts executed with the DOE. The DOE did not begin accepting spent fuel in 1998 as specified in its contract. As a result, Virginia Power sought reimbursement for certain spent nuclear fuel-related costs incurred and in 2012 signed a settlement agreement with the DOE. By mutual agreement of the parties, the settlement agreement is extendable to provide for resolution of damages. The settlement agreement has been extended to provide for periodic payments for damages incurred through December 31, 2019, and additional extensions are contemplated by the settlement agreement. We continue to recognize receivables for certain spent nuclear fuel-related costs. We believe the recovery of these costs from the DOE is probable. As of December 31, 2019 and 2018, we had an outstanding receivable of $3.9 million and $4.7 million, respectively.

Fuel, Materials, and Supplies

Fuel, materials, and supplies is primarily composed of fuel and spare parts for our generating assets, and renewable energy credits, all of which are recorded at cost. Fuel consists primarily of coal and No. 2 fuel oil.

Allowance for Borrowed Funds Used During Construction

Allowance for borrowed funds used during construction is defined as the net cost of borrowed funds used for construction purposes during the construction period and a reasonable rate on other funds when so used. We capitalize interest on borrowings for significant construction projects. Interest capitalized in 2019, 2018, and 2017, was $0.5 million, $11.2 million, and $35.6 million, respectively.

Income Taxes

We are a not-for-profit electric cooperative and are currently exempt from federal income taxation under IRC Section 501(c)(12), and we intend to continue to operate in this manner. Based on our assessment and evaluations of relevant authority, we believe we could sustain treatment as a tax-exempt utility in the event of a challenge of our tax status. Accordingly, no provision for income taxes has been recorded based on ODEC's operations in the accompanying consolidated financial statements.

TEC is a taxable corporation and its provision for income taxes was immaterial for the years ended December 31, 2019, 2018, and 2017.

Operating Revenues

Our operating revenues are derived from sales to our members and non-members. We supply power requirements (energy and demand) to our eleven member distribution cooperatives subject to substantially identical wholesale power contracts with each of them. 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. See Note 5—Wholesale Power Contracts. 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 sell excess purchased and generated energy to PJM, TEC, or third parties. Sales to TEC consist of sales of excess energy that we do not need to meet the actual needs of our member distribution cooperatives. TEC's sales to third parties are reflected as non-member revenues. In 2019, 2018, and 2017, we had no sales to TEC and TEC had no sales to third parties.

Our operating revenues for the past three years were as follows:

	Year Ended December 31,		
	2019	2018	2017
		(in thousands)	
Member distribution cooperatives			
Sales to member distribution cooperatives, excluding renewable energy credit sales	$ 898,445	$ 865,393	$ 731,557
Renewable energy credit sales to member distribution cooperatives	26	16	19
Total Sales to member distribution cooperatives	$ 898,471	$ 865,409	$ 731,576
Non-members			
Sales to non-members, excluding renewable energy credit sales	$ 29,539	$ 64,209	$ 16,356
Renewable energy credit sales to non-members	4,672	2,950	5,175
Total sales to non-members	$ 34,211	$ 67,159	$ 21,531
Total operating revenues	$ 932,682	$ 932,568	$ 753,107

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 natural gas, nuclear, and coal 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 capacity costs under power purchase contracts with third parties, transmission costs, administrative and general expenses, depreciation expense, interest expense, margin requirement, 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 requirement, 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. See "Margin Stabilization" below.

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.

Margin Stabilization

Margin Stabilization allows us to review our actual demand-related costs of service and demand revenues 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 collect and return amounts utilizing Margin Stabilization. We record all adjustments, whether increases or decreases, in the year affected and allocate any adjustments to our member distribution cooperatives based on power sales during that year. We collect these increases from our member distribution cooperatives, or offset decreases against amounts owed by our member distribution cooperatives to us, generally in the succeeding calendar year. We adjust operating revenues and accounts receivable–members or accounts payable–members, as appropriate, to reflect these adjustments. These adjustments are treated as due, owed, incurred, and accrued for the year to which the adjustment relates. The following table details the reduction in revenues utilizing Margin Stabilization for the past three years:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in thousands)	
Margin Stabilization adjustment	$7,175	$15,312	$34,144

Regulatory Assets and Liabilities

We account for certain revenues and expenses as a rate-regulated entity in accordance with Accounting for Regulated Operations. This allows certain of our revenues and expenses to be deferred at the discretion of our board of directors, which has budgetary and rate setting authority, if it is probable that these amounts will be collected or returned through our formula rate in future periods. Regulatory assets represent costs that we expect to collect from our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. Regulatory liabilities represent probable future reductions in our revenues associated with amounts that we expect to return to our member distribution cooperatives based on rates approved by our board of directors in accordance with our formula rate. Regulatory assets are generally included in deferred charges and other assets and regulatory liabilities are generally included in deferred credits and other liabilities. Deferred energy, which can be either a regulatory asset or a regulatory liability, is included in current assets or current liabilities, respectively. See “Deferred Energy” below. We recognize regulatory assets and liabilities as expenses or as a reduction in expenses, respectively, concurrent with their recovery through rates.

Debt Issuance Costs

Capitalized costs associated with the issuance of long-term debt totaled $6.2 million and $6.7 million as of December 31, 2019 and 2018, respectively, and are included as a direct reduction to long-term debt. Capitalized costs associated with our revolving credit facility totaled $1.0 million as of December 31, 2019 and 2018, and are recorded in deferred charges and other assets–other. These costs are being amortized using the effective interest method over the life of the respective long-term debt issuances and revolving credit facility, and are included in interest charges, net.

Deferred Energy

In accordance with Accounting for Regulated Operations, we use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. The deferred energy balance represents the net accumulation of any under- or over-collection of energy costs. Under-collected energy costs appear as an asset and will be collected from our member distribution cooperatives in subsequent periods through our formula rate. Conversely, over-collected energy costs appear as a liability and will be returned to our member distribution cooperatives in subsequent periods through our formula rate. As of December 31, 2019 and 2018, we had an under-collected deferred energy balance of $3.5 million and $26.1 million, respectively.

The following table summarizes the changes to our total energy rate since 2017, which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Rate Change	% Change
January 1, 2017	(6.7)
January 1, 2018	11.1
April 1, 2018	3.7
January 1, 2019	(1.3)
January 1, 2020	(16.2)

Financial Instruments (including Derivatives)

Investments included in the nuclear decommissioning trust are carried at fair value. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or a regulatory asset, respectively, until realized.

Unrestricted investments in debt securities that we have the positive intent and ability to hold to maturity are recorded at amortized cost. Non-marketable equity investments, which are accounted for under the equity method, are included in other investments and recorded at cost. Equity securities in other investments are recorded at fair value. See Note 9—Investments.

We primarily purchase power under both long-term and short-term physically-delivered forward contracts to supply power to our member distribution cooperatives. These forward purchase contracts meet the accounting definition of a derivative; however, a majority of these forward purchase derivative contracts qualify for the normal purchases/normal sales accounting exception under Accounting for Derivatives and Hedging. As a result, these contracts are not recorded at fair value. We record a liability and purchased power expense when the power under the physically-delivered forward contract is delivered. We also purchase natural gas futures generally for three years or less to hedge the price of natural gas for our facilities which utilize natural gas. These derivatives do not qualify for the normal purchases/normal sales accounting exception.

For all derivative contracts that do not qualify for the normal purchases/normal sales accounting exception, we defer all remaining gains and losses on a net basis as a regulatory liability or regulatory asset, respectively, in accordance with Accounting for Regulated Operations. These amounts are subsequently reclassified as purchased power or fuel expense as the power or fuel is delivered and/or the contract settles.

Generally, derivatives are reported at fair value on the Consolidated Balance Sheet in the regulatory assets or regulatory liabilities account, and deferred charges and other assets–other or deferred credits and other liabilities–other. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, we seek indicative price information from external sources, including broker quotes and industry publications. For individual contracts, the use of differing assumptions could have a material effect on the contract's estimated fair value.

Patronage Capital

We are organized and operate as a cooperative. Patronage capital represents our retained net margins, which have been allocated to our members based upon their respective power purchases in accordance with our bylaws. Any distributions of patronage capital are subject to the discretion of our board of directors and the restrictions contained in our Indenture. See Note 11—Long-term Debt for discussion of the restrictions contained in the Indenture.

We operate on a not-for-profit basis and, accordingly, seek to generate revenues sufficient to recover our cost of service and produce margins sufficient to establish reasonable reserves, meet financial coverage requirements, and accumulate additional equity approved by our board of directors. Revenues in excess of expenses in any year are designated as net margin attributable to ODEC on our Consolidated Statements of Revenues, Expenses, and Patronage Capital. We designate retained net margins attributable to ODEC on our Consolidated Balance Sheet as patronage capital, which we assign to each of our members on the basis of its class of membership and business with us.

On November 19, 2019, our board of directors approved an additional equity contribution of $4.3 million, and subsequently declared a patronage capital retirement of $4.3 million. As a result of the November 19, 2019, declaration, we reduced patronage capital and increased accounts payable–members by $4.3 million. The $4.3 million patronage capital retirement will be paid on March 27, 2020.

On November 7, 2017, our board of directors approved an additional equity contribution of $14.1 million, and subsequently declared a patronage capital retirement of $14.1 million. As a result of the November 7, 2017, declaration, we reduced patronage capital and increased accounts payable–members by $14.1 million. The $14.1 million patronage capital retirement was paid on April 2, 2018.

Concentrations of Credit Risk

Financial instruments that potentially subject us to concentrations of credit risk consist of cash equivalents, investments, derivatives, and receivables arising from sales to our members and non-members. Concentrations of credit risk with respect to receivables arising from sales to our member distribution cooperatives as reflected by accounts receivable–members were $101.2 million and $84.4 million, as of December 31, 2019 and 2018, respectively.

Segment

We are organized for the purpose of supplying the power our member distribution cooperatives require to serve their customers on a cost-effective basis. Our President and CEO serves as our chief decision-maker who manages and reviews our operating results as one operating, and therefore one reportable, segment. We supply our member distribution cooperatives' energy and demand requirements through a portfolio of resources including generating facilities, physically-delivered forward power purchase contracts, and spot market energy purchases.

Cash and Cash Equivalents

For purposes of our Consolidated Statements of Cash Flows, we consider all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

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

	As of December 31,	
	2019	2018
	(in thousands)	
Cash and cash equivalents	$ 3,469	$ 8,649
Restricted cash and cash equivalents	24,230	14,329
Total	$ 27,699	$ 22,978

Restricted cash and cash equivalents relates to funds held in escrow for payments related to the construction of Wildcat Point.

New Accounting Pronouncements

In February 2016, the FASB issued ASU 2016-02 Leases which revised accounting guidance for the recognition, measurement, presentation, and disclosure of leasing arrangements. In July 2018, the FASB issued ASU 2018-11 Leases (Topic 842): Targeted Improvements, which provides an adoption method that would allow companies to apply the new guidance to the financial statements in the period of adoption and thereafter, and not apply the new guidance to comparative periods presented. Effective January 1, 2019, we elected the adoption method provided by ASU 2018-11 (Topic 842) and are not adjusting prior year comparative financial statements. We also elected the package of practical expedients under the transition guidance which permits us not to reassess under the new standard our prior conclusions for lease identification and lease classification on expired or existing contracts and whether initial direct costs previously capitalized would qualify for capitalization under ASU 2018-11 (Topic 842). Additionally, we elected the practical expedient related to land easements, allowing us to not reassess our current accounting treatment for existing agreements on land easements, which are not accounted for as leases. Upon adoption of the new lease standard, we recognized right-of-use assets and offsetting lease liabilities totaling approximately $0.1 million.

In June 2016, the FASB issued ASU 2016-13 Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses in Financial Instruments. FASB issued subsequent amendments to the initial guidance in November 2018 with ASU No. 2018-19, in April 2019 with ASU No. 2019-04, and in May 2019 with ASU No. 2019-05. The ASU amends the guidance on the impairment of financial instruments and adds an impairment model, known as the current expected credit loss ("CECL") model. The CECL model requires an entity to recognize its current estimate of all expected credit losses, rather than incurred losses, and applies to trade receivables and other receivables. The CECL model is designed to capture expected credit losses through the establishment of an allowance account, which will be presented as an offset to the amortized cost basis of the related financial asset. The new guidance is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and is applied using the modified-retrospective approach. We have evaluated the impact of this pronouncement and currently do not anticipate a material impact from adopting this standard. We plan to adopt this standard for the fiscal year beginning January 1, 2020.

NOTE 2—Electric Plant

Our net electric plant was composed of the following as of December 31, 2019:

	Wildcat Point	North Anna	Clover	Combustion Turbine Facilities	Other	Total
	(in thousands)					
Property, plant, and equipment	$874,860	$ 411,658	$ 704,004	$ 443,092	$ 98,372	$2,531,986
Accumulated depreciation	(44,632)	(237,893)	(390,528)	(222,419)	(31,593)	(927,065)
Net Property, plant, and equipment	830,228	173,765	313,476	220,673	66,779	1,604,921
Nuclear fuel, at amortized cost	—	20,705	—	—	—	20,705
Construction work in progress	115	24,013	4,995	—	2,339	31,462
Net Electric Plant	$830,343	$ 218,483	$ 318,471	$ 220,673	$ 69,118	$1,657,088

Our net electric plant was composed of the following as of December 31, 2018:

	Wildcat Point [(1)]	North Anna	Clover	Combustion Turbine Facilities	Other	Total
	(in thousands)					
Property, plant, and equipment	$842,908	$ 372,157	$ 696,659	$ 444,481	$ 98,363	$2,454,568
Accumulated depreciation	(18,486)	(227,678)	(380,737)	(212,388)	(30,189)	(869,478)
Net Property, plant, and equipment	824,422	144,479	315,922	232,093	68,174	1,585,090
Nuclear fuel, at amortized cost	—	14,694	—	—	—	14,694
Construction work in progress	920	25,840	10,769	—	2,583	40,112
Net Electric Plant	$825,342	$ 185,013	$ 326,691	$ 232,093	$ 70,757	$1,639,896

(1) Capitalized construction costs have been offset by $53.2 million of liquidated damages.

Wildcat Point

We own Wildcat Point, a 973 MW (net capacity entitlement) natural gas-fueled combined cycle generation facility. Wildcat Point achieved commercial operation on April 17, 2018. In 2017, WOPC, a joint venture between PCL Industrial Construction Company and Sargent & Lundy, L.L.C., as EPC contractor, made a claim against Alstom and us for recovery of additional amounts under the EPC contract for Wildcat Point. Additionally, in 2017, we filed a complaint alleging that WOPC breached the EPC contract. Subsequently, 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, be consolidated. In December 2019, ODEC and WOPC held formal settlement discussions and we recognized the probable impact of the settlement as of December 31, 2019, resulting in a $29.6 million increase to property, plant, and equipment. On January 9, 2020, ODEC and WOPC settled their dispute and ODEC was dismissed as a party from the case.

North Anna

We hold an 11.6% undivided ownership interest in North Anna, a two-unit, 1,892 MW (net capacity entitlement) nuclear power facility operated by Virginia Power, which owns the balance of the plant. We are responsible for and must fund 11.6% of all post-acquisition date additions and operating costs associated with North Anna, as well as a pro-rata portion of Virginia Power's administrative and general expenses directly attributable to North Anna. Our portion of assets, liabilities, and operating expenses associated with North Anna are included on our consolidated financial statements in accordance with proportionate consolidation accounting. As of December 31, 2019 and 2018, we had an outstanding accounts payable balance of $6.2 million and $6.6 million, respectively, due to Virginia Power for operation, maintenance, and capital investment at North Anna.

Clover

We hold a 50% undivided ownership interest in Clover, a two-unit, 877 MW (net capacity entitlement) coal-fired electric generation facility operated by Virginia Power, which owns the balance of the plant. We are responsible for and must fund half of all additions and operating costs associated with Clover, as well as half of Virginia Power's administrative and general expenses directly attributable to Clover. Our portion of assets, liabilities, and operating expenses associated with Clover are included on our consolidated financial statements in accordance with proportionate consolidation accounting. As of December 31, 2019 and 2018, we had an outstanding accounts payable balance of $6.8 million and $12.3 million, respectively, due to Virginia Power for operation, maintenance, and capital investment at Clover.

Combustion Turbine Facilities

We own two combustion turbine facilities, Louisa and Marsh Run that are primarily fueled by natural gas.

Prior to September 14, 2018, we owned a third combustion turbine facility, Rock Springs. On September 14, 2018, we sold our interest in Rock Springs and related assets to EPRS for $115 million. Prior to the sale, we and EPRS had each individually owned two natural gas-fired combustion turbine units and a 50% undivided interest in related common facilities at Rock Springs. The transaction resulted in a gain of $42.7 million, which our board of directors approved to defer as a regulatory liability. We amortized $5.0 million of the gain in 2018 and the remaining $37.7 million was amortized in 2019.

Other

We also own six distributed generation facilities and approximately 110 miles of transmission lines on the Virginia portion of the Delmarva Peninsula.

NOTE 3—Accounting for Asset Retirement and Environmental Obligations

We account for our asset retirement obligations in accordance with Accounting for Asset Retirement and Environmental Obligations. This requires that legal obligations associated with the retirement of long-lived assets be recognized at fair value when incurred and capitalized as part of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized asset is depreciated over the useful life of the long-lived asset.

In the absence of quoted market prices, we estimate the fair value of our asset retirement obligations using present value techniques, in which estimates of future cash flows associated with retirement activities are discounted using a credit-adjusted risk-free rate. Our estimated liability could change significantly if actual costs vary from assumptions or if governmental regulations change significantly.

A significant portion of our asset retirement obligations relates to our share of the future costs to decommission North Anna. At December 31, 2019 and 2018, our share of North Anna's nuclear decommissioning asset retirement obligation totaled $152.4 million and $110.2 million, respectively. Approximately every four years, a new decommissioning study for North Anna is performed by third-party experts. A new study was performed in 2019, and we adopted it effective December 31, 2019, which resulted in an additional layer related to the asset retirement obligation associated with North Anna. The additional layer resulted in an increase to our asset retirement cost and our asset retirement obligation of $37.6 million. The increase is related to costs associated with spent fuel, including the change in methodology to be utilized, as a result of the DOE delay for acceptance of spent fuel, as well as the change in the market risk premium and inflation rates utilized to calculate our costs. We are not aware of any events that have occurred since the 2019 study that would materially impact our estimate. We are required to maintain a funded trust to satisfy our future obligation to decommission the North Anna facility. See Note 9—Investments.

In 2018, we also recorded a $0.4 million decrease in the asset retirement obligation related to Clover as a result of a difference in estimated and actual costs for an asset retirement obligation.

The following represents changes in our asset retirement obligations for the years ended December 31, 2019 and 2018 (in thousands):

Asset retirement obligations as of December 31, 2017	$ 126,470
Accretion expense	5,319
Decrease in asset retirement obligations	(570)
Payments	(731)
Asset retirement obligations as of December 31, 2018	$ 130,488
Accretion expense	5,539
Increase in asset retirement obligations - new layer	37,642
Asset retirement obligations as of December 31, 2019	$ 173,669

The cash flow estimates for North Anna's asset retirement obligation are based upon an assumption of an additional 20-year life extension, which will extend the life of Unit 1 to April 1, 2058, and the life of Unit 2 to August 21, 2060. Virginia Power, the co-owner of North Anna, has announced its intention to apply for an additional 20-year operating license extension for North Anna in late 2020. Given the life extension, the nuclear decommissioning trust was, and currently is, estimated to be adequate to fund North Anna's asset retirement obligation and no additional funding was, or is, currently required. We ceased collection of decommissioning expense in August 2003 with the approval of FERC. As we are not currently collecting decommissioning expense in our rates, we are deferring the difference between the earnings on the nuclear decommissioning trust and the total asset retirement obligation related depreciation and accretion expense for North Anna as part of our asset retirement obligation regulatory liability. See Note 10—Regulatory Assets and Liabilities.

NOTE 4—Power Purchase Agreements

In 2019, 2018, and 2017, our owned generating facilities together furnished approximately 56.3%, 57.1%, and 36.7%, respectively, of our energy requirements. The remaining needs were satisfied through purchases of power in the market from investor-owned utilities and power marketers through long-term and short-term physically-delivered forward power purchase contracts. We also purchased power in the spot energy market. This approach to meeting our member distribution cooperatives' energy requirements is not without risks. To mitigate these risks, we attempt to match our energy purchases with our energy needs to reduce our spot market purchases of energy and sales of excess energy. Additionally, we utilize policies, procedures, and various hedging instruments to manage our power market price risks. These policies and procedures, developed in consultation with ACES, an energy trading and risk management company, are designed to strike an appropriate balance between minimizing costs and reducing energy cost volatility. We are required to post collateral from time to time due to changes in power prices. Additionally, we may be required to post collateral with PJM to support our obligations in connection with our PJM transactions. As of December 31, 2019 and 2018, we had posted a $0.5 million letter of credit and a $2.5 million letter of credit, respectively.

Our purchased power expense for 2019, 2018, and 2017 was $332.2 million, $397.6 million, and $397.4 million, respectively.

As of December 31, 2019, our power purchase obligations under the various agreements were as follows:

Year Ended December 31,	Capacity and Energy Obligations
	(in millions)
2020	$ 130.5
2021	3.6
2022	0.8
	$ 134.9

NOTE 5—Wholesale Power Contracts

Our financial relationships with our member distribution cooperatives are based primarily on our contractual arrangements for the supply of power and related transmission and ancillary services. These arrangements are set forth in our wholesale power contracts with our member distribution cooperatives that are effective until January 1, 2054, and beyond this date unless either party gives the other at least three years notice of termination. The wholesale power contracts are all-requirements contracts. Each contract obligates us to sell and deliver to a member distribution cooperative, and obligates that member distribution cooperative to purchase and receive from us, all power that it requires for the operation of its system, with limited exceptions, to the extent that we have the power and facilities available to do so.

An exception to the all-requirements obligations of our member distribution cooperatives relates to the ability of our eight mainland Virginia member distribution cooperatives to purchase hydroelectric power allocated to them from SEPA, a federal power marketing administration. We estimate that purchases under this exception constituted approximately 2% of our member distribution cooperatives' total energy requirements in 2019.

There are two additional limited exceptions to the all-requirements nature of the contracts. One exception 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. The other exception permits our member distribution cooperatives to purchase additional power from other suppliers in limited circumstances following approval by our board of directors; as of December 31, 2019, none of our member distribution cooperatives had utilized this exception.

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 178 MW of demand and associated energy. The following table summarizes the cumulative removal of load requirements under this exception.

As of December 31,	MW
2017	65
2018	107
2019	108

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.

Each member distribution cooperative is required to pay us monthly for power furnished under its wholesale power contract in accordance with our formula rate. We review our formula rate design at least every three years to consider whether it is appropriately achieving its intended results. The formula rate, which has been filed with and accepted by FERC, is designed to recover our total cost of service and create a firm equity base. See Note 1—Summary of Significant Accounting Policies—Formula Rate.

More specifically, the formula rate is intended to meet all of our costs, expenses, and financial obligations associated with our ownership, operation, maintenance, repair, replacement, improvement, modification, retirement, and decommissioning of our generating plants, transmission system, or related facilities; services provided to the member distribution cooperatives; and the acquisition and transmission of power or related services, including:

- payments of principal and premium, if any, and interest on all indebtedness issued by us (other than payments resulting from the acceleration of the maturity of the indebtedness);
- any additional cost or expense, imposed or permitted by any regulatory agency; and
- additional amounts necessary to meet the requirement of any rate covenant with respect to coverage of principal and interest on our indebtedness contained in any indenture or contract with holders of our indebtedness.

The rates established under the wholesale power contracts are designed to enable us to comply with financing, regulatory, and governmental requirements that apply to us from time to time.

Because modifications to our formula rate are not intended to modify the aggregate amount that we collect from our member distribution cooperatives, but rather how we allocate that aggregate amount, the opportunity exists for disagreements among one or more of our member distribution cooperatives, or with us, regarding the best formula rate structure. As the factors impacting our costs become more complex, the potential for these disagreements increases.

Revenues from our member distribution cooperatives for the past three years were as follows:

	Year Ended December 31,		
	2019	**2018**	**2017**
		(in millions)	
Rappahannock Electric Cooperative	$ 279.7	$ 266.9	$ 217.7
Shenandoah Valley Electric Cooperative	168.4	164.7	146.8
Delaware Electric Cooperative, Inc.	121.6	115.5	97.5
Choptank Electric Cooperative, Inc.	83.1	81.2	69.7
Southside Electric Cooperative	69.8	67.7	58.4
A&N Electric Cooperative	54.7	53.7	46.0
Mecklenburg Electric Cooperative	45.1	44.0	36.7
Prince George Electric Cooperative	26.9	25.7	20.6
Northern Neck Electric Cooperative	24.1	22.2	18.2
Community Electric Cooperative	14.1	13.5	11.4
BARC Electric Cooperative	11.0	10.3	8.6
Total	$ 898.5	$ 865.4	$ 731.6

NOTE 6—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 December 31, 2019 and 2018:

	December 31, 2019	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)]	$ 64,504	$ 64,504	$ —	$ —
Nuclear decommissioning trust - net asset value [(1)(2)]	146,604	—	—	—
Unrestricted investments and other [(3)]	126	—	126	—
Derivatives - gas and power [(4)]	1,013	—	—	1,013
Total Financial Assets	$ 212,247	$ 64,504	$ 126	$ 1,013
Derivatives - gas and power [(4)]	$ 24,125	$ 17,109	$ 7,016	$ —
Total Financial Liabilities	$ 24,125	$ 17,109	$ 7,016	$ —

	December 31, 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)]	$ 59,150	$ 59,150	$ —	$ —
Nuclear decommissioning trust - net asset value [(1)(2)]	114,801	—	—	—
Unrestricted investments and other [(3)]	394	—	394	—
Derivatives - gas and power [(4)]	784	—	784	—
Total Financial Assets	$ 175,129	$ 59,150	$ 1,178	$ —
Derivatives - gas and power [(4)]	$ 591	$ 591	$ —	$ —
Total Financial Liabilities	$ 591	$ 591	$ —	$ —

(1) For additional information about our nuclear decommissioning trust, see Note 9—Investments.

(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 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 and Level 2) and financial transmission rights (Level 3). Level 1 are indexed against NYMEX. Level 2 are valued by ACES using observable market inputs for similar transactions. Level 3 are valued by ACES using unobservable market inputs, including situations where there is little market activity. For additional information about our derivative financial instruments, see Note 1—Summary of Significant Accounting Policies.

We recorded the fair value of financial transmission rights (Level 3) in 2019 and as of December 31, 2019, the fair value was $1.0 million. Sensitivity in the market price of financial transmission rights could impact the fair value. The unrealized gain (change in market value) was reported in regulatory assets in our Consolidated Balance Sheet as of December 31, 2019.

NOTE 7 — 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—Summary of Significant Accounting Policies.

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 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 December 31, 2019**	**As of December 31, 2018**
Natural Gas	MMBTU	73,560,000	36,790,000
Purchased power - financial transmission rights	MWh	5,771,291	—

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 December 31, 2019**	**As of December 31, 2018**
		(in thousands)	
Derivatives in an asset position:			
Natural gas futures contracts	Deferred charges and other assets-other	$ —	$ 784
Financial transmission rights	Deferred charges and other assets-other	1,013	—
Total derivatives in an asset position		$ 1,013	$ 784
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	$ 24,125	$ 591
Total derivatives in a liability position		$ 24,125	$ 591

The Effect of Derivative Instruments on the Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Years Ended December 31, 2019 and 2018

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of December 31, 2019	2018	Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income	Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Year Ended December 31, 2019	2018
	(in thousands)			(in thousands)	
Natural gas futures contracts	$ (25,996)	$ 1,286	Fuel	$ (19,770)	$ 2,512
Purchased power	1,013	—	Purchased Power	(4,579)	—
Total	$ (24,983)	$ 1,286		$ (24,349)	$ 2,512

NOTE 8—Long-term Lease Transaction

On March 1, 1996, we entered into a long-term lease transaction with an owner trust for the benefit of an investor. Under the terms of the transaction, we entered into a 48.8 year lease of our interest in Clover Unit 1, valued at $315.0 million, to such owner trust, and immediately after we entered into a 21.8 year lease of the interest back from such owner trust. As a result of the transaction, we recorded a deferred gain of $23.7 million, which was amortized into income ratably over the 21.8 year operating lease term, as a reduction to depreciation and amortization expense. As of December 31, 2017, the deferred gain was fully amortized.

We used a portion of the one-time rental payment of $315.0 million we received to enter into a payment undertaking agreement and to purchase an investment that would provide for substantially all of our periodic rent payments under the leaseback, and the fixed purchase price of the interest in the unit at the end of the term of the leaseback if we were to exercise our option to purchase the interest of the owner trust in the unit at that time. As of December 31, 2017, the payment undertaking agreement had a balance of $304.7 million, and the amount of debt considered to be extinguished by in substance defeasance was $304.7 million.

We elected to purchase the owner trust’s interest in the unit and terminate the lease effective January 5, 2018, for a fixed purchase price of $430.5 million. On January 5, 2018, payments under the payment undertaking agreement funded $289.7 million of this amount, and $32.2 million was provided by us and in turn paid to us as the holder of a loan to the owner trust. The remaining balance of the fixed purchase price was funded by United States Treasury securities with a maturity value of $108.6 million and was paid in four installments during 2018.

NOTE 9—Investments

Investments were as follows as of December 31, 2019 and 2018:

Description	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
			(in thousands)		
December 31, 2019					
Nuclear decommissioning trust [1]					
Debt securities	$ 59,748	$ 4,325	$ —	$ 64,073	$ 64,073
Equity securities	85,303	63,858	(2,557)	146,604	146,604
Cash and other	431	—	—	431	431
Total Nuclear Decommissioning Trust	$ 145,482	$ 68,183	$ (2,557)	$ 211,108	$ 211,108
Unrestricted investments					
Government obligations	$ 2,869	$ 4	$ —	$ 2,873	$ 2,869
Debt securities	240	—	—	240	240
Total Unrestricted Investments	$ 3,109	$ 4	$ —	$ 3,113	$ 3,109
Other					
Equity securities	$ 110	$ 15	$ —	$ 125	$ 125
Non-marketable equity investments	2,146	2,176	—	4,322	2,146
Total Other	$ 2,256	$ 2,191	$ —	$ 4,447	$ 2,271
					$ 216,488
December 31, 2018					
Nuclear decommissioning trust [1]					
Debt securities	$ 56,055	$ 2,955	$ —	$ 59,010	$ 59,010
Equity securities	83,453	38,611	(7,264)	114,800	114,800
Cash and other	141	—	—	141	141
Total Nuclear Decommissioning Trust	$ 139,649	$ 41,566	$ (7,264)	$ 173,951	$ 173,951
Unrestricted investments					
Government obligations	$ 4,935	$ —	$ (5)	$ 4,930	$ 4,935
Debt securities	595	—	(2)	593	595
Total Unrestricted Investments	$ 5,530	$ —	$ (7)	$ 5,523	$ 5,530
Other					
Equity securities	$ 347	$ 46	$ —	$ 393	$ 393
Non-marketable equity investments	2,143	2,080	—	4,223	2,143
Total Other	$ 2,490	$ 2,126	$ —	$ 4,616	$ 2,536
					$ 182,017

[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—Accounting for Asset Retirement and Environmental Obligations. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or regulatory asset, respectively.

Contractual maturities of debt securities as of December 31, 2019, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Other [1]	$ —	$ —	$ 64,073	$ —	$ 64,073
Held to maturity	3,109	—	—	—	3,109
Total	$ 3,109	$ —	$ 64,073	$ —	$ 67,182

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

NOTE 10—Regulatory Assets and Liabilities

In accordance with Accounting for Regulated Operations, we record regulatory assets and liabilities that result from our ratemaking. Our regulatory assets and liabilities as of December 31, 2019 and 2018, were as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	$ 6,247	$ 8,112
Deferred asset retirement costs	263	280
NOVEC contract termination fee	22,022	24,468
Interest rate hedge	1,907	2,062
Voluntary prepayment to NRECA Retirement Security Plan	2,320	3,094
Deferred net unrealized losses on derivative instruments	24,983	—
Total Regulatory Assets	$ 57,742	$ 38,016
Regulatory Assets included in Current Assets:		
Deferred energy	$ 3,548	$ 26,069
Regulatory Liabilities:		
North Anna asset retirement obligation deferral	$ 51,626	$ 51,422
North Anna nuclear decommissioning trust unrealized gain	65,626	34,302
Unamortized gains on reacquired debt	231	290
Deferred net unrealized gains on derivative instruments	—	1,286
Total Regulatory Liabilities	$ 117,483	$ 87,300
Regulatory Liabilities included in Current Liabilities:		
Regulatory liability–deferral of gain on sale of asset	$ —	$ 37,723

The regulatory assets will be recognized as expenses concurrent with their collection through rates and the regulatory liabilities will be recognized as reductions to expenses concurrent with their return through rates.

Regulatory assets included in deferred charges and other assets are detailed as follows:

- Unamortized losses on reacquired debt are the costs we incurred to purchase our outstanding indebtedness prior to its scheduled retirement. These losses are amortized over the life of the original indebtedness and will be fully amortized in 2023.
- Deferred asset retirement costs reflect the cumulative effect of change in accounting principle for the Clover and distributed generation facilities as a result of the adoption of Accounting for Asset Retirement and Environmental Obligations. These costs will be fully amortized in 2034.

- NOVEC contract termination fee reflects the amount allocated to the contract value of the payment to NOVEC in 2008 as part of the termination agreement. The wholesale power contract with NOVEC was scheduled to expire in 2028, thus the contract termination fee will be amortized ratably through 2028 through amortization of regulatory asset/(liability), net.
- Interest rate hedge. To mitigate a portion of our exposure to fluctuations in long-term interest rates related to the debt we issued in 2011, we entered into an interest rate hedge. This will be amortized over the life of the 2011 debt and will be fully amortized in 2050.
- Voluntary prepayment to NRECA Retirement Security Plan. In April 2013, we elected to make a voluntary prepayment of $7.7 million to the NRECA Retirement Security Plan, a noncontributory, defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the IRC. It is considered a multi-employer plan under accounting standards. We recorded this prepayment as a regulatory asset which will be fully amortized in 2022. See Note 13—Employee Benefits.
- Deferred net unrealized losses on derivative instruments will be matched and recognized in the same period the expense is incurred for the hedged item.

Regulatory assets included in current assets are detailed as follows:

- Deferred energy balance represents the net accumulation of under-collection of energy costs. We use the deferral method of accounting to recognize differences between our energy expenses and our energy revenues collected from our member distribution cooperatives. Under-collected deferred energy balances are collected from our member distribution cooperatives in subsequent periods.

Regulatory liabilities included in deferred credits and other liabilities are detailed as follows:

- North Anna asset retirement obligation deferral is the cumulative effect of change in accounting principle as a result of the adoption of Accounting for Asset Retirement and Environmental Obligations plus the deferral of subsequent activity primarily related to accretion expense offset by interest income on the nuclear decommissioning trust.
- North Anna nuclear decommissioning trust unrealized gain reflects the unrealized gain on the investments in the nuclear decommissioning trust.
- Unamortized gains on reacquired debt are the gains we recognized when we purchased our outstanding indebtedness prior to its scheduled retirement. These gains are amortized over the life of the original indebtedness and will be fully amortized in 2023.
- Deferred net unrealized gains on derivative instruments will be matched and recognized in the same period the expense is incurred for the hedged item.

Regulatory liabilities included in current liabilities are detailed as follows:

- Regulatory liability–deferral of gain on sale of asset. On September 14, 2018, we sold our interest in Rock Springs and related assets to EPRS for $115 million, resulting in a gain of $42.7 million. We amortized $5.0 million of the gain in 2018 and the remaining $37.7 million was amortized in 2019.

NOTE 11—Long-term Debt

Long-term debt consists of the following:

	December 31, 2019	December 31, 2018
	(in thousands)	
$250,000,000 principal amount of First Mortgage Bonds, 2017 Series A due 2037 at an interest rate of 3.33%	$ 225,000	$ 237,500
$260,000,000 principal amount of First Mortgage Bonds, 2015 Series A due 2044 at an interest rate of 4.46%	260,000	260,000
$72,000,000 principal amount of First Mortgage Bonds, 2015 Series B due 2053 at an interest rate of 4.56%	72,000	72,000
$50,000,000 principal amount of First Mortgage Bonds, 2013 Series A due 2043 at an interest rate of 4.21%	50,000	50,000
$50,000,000 principal amount of First Mortgage Bonds, 2013 Series B due 2053 at an interest rate of 4.36%	50,000	50,000
$90,000,000 principal amount of First Mortgage Bonds, 2011 Series A due 2040 at an interest rate of 4.83%	63,000	66,000
$165,000,000 principal amount of First Mortgage Bonds, 2011 Series B due 2040 at an interest rate of 5.54%	165,000	165,000
$95,000,000 principal amount of First Mortgage Bonds, 2011 Series C due 2050 at an interest rate of 5.54%	73,625	76,000
$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	93,745	104,162
$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	112,500	125,000
	1,164,870	1,205,662
Debt issuance costs	(6,211)	(6,729)
Current maturities	(40,792)	(40,792)
	$ 1,117,867	$ 1,158,141

As of December 31, 2019 and 2018, deferred gains and losses on reacquired debt totaled a net loss of approximately $6.0 million and $7.8 million, respectively. Deferred gains and losses on reacquired debt are deferred under regulatory accounting. See Note 10—Regulatory Assets and Liabilities.

Maturities of long-term debt for the next five years and thereafter are as follows:

Year Ended December 31,	(in thousands)
2020	$ 40,792
2021	49,041
2022	49,041
2023	49,041
2024	49,041
2025 and thereafter	927,914
	$ 1,164,870

The aggregate fair value of long-term debt was $1,300.1 million and $1,231.5 million as of December 31, 2019 and 2018, respectively, based on current market prices. For debt issues that are not quoted on an exchange, interest rates currently available to us for issuance of debt with similar terms and remaining maturities are used to estimate fair value.

All of our long-term debt is secured under our Indenture. Substantially all of our real property and tangible personal property and some of our intangible personal property are pledged as collateral under the Indenture. Under the Indenture, we may not make any distribution, including a dividend or payment or retirement of patronage capital, to our members if an event of default exists under the Indenture. Otherwise, we may make a distribution to our members if (1) after the distribution, our patronage capital as of the end of the most recent fiscal quarter would be equal to or greater than 20% of our total long-term debt and patronage capital, or (2) all of our distributions for the year in which the distribution is to be made do not exceed 5% of the patronage capital as of the end of the most recent fiscal year. For this purpose, patronage capital and total long-term debt do not include any earnings retained in any of our subsidiaries or affiliates or the debt of any of our subsidiaries or affiliates.

Additionally, we maintain a revolving credit facility. See Note 12—Liquidity Resources.

NOTE 12—Liquidity Resources

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 through February 28, 2025. Available funding under this facility totals $500 million through March 3, 2022, and $400 million from March 4, 2022 through February 28, 2025. As of December 31, 2019, we had outstanding under this facility, $67.2 million in borrowings at a weighted average interest rate of 2.8% and a $0.5 million letter of credit. We did not have any borrowings outstanding under this facility as of December 31, 2018; however, the interest rate on borrowings would have been 3.5%. As of December 31, 2018, we had a $2.5 million letter of credit outstanding under this facility. As of March 10, 2020, we had outstanding under this facility, $115.0 million in borrowings and a $0.5 million letter of credit.

Borrowings under the credit agreement that are based on Eurodollar rates bear interest at LIBOR plus a margin ranging from 0.90% to 1.5%, depending on our credit ratings. Borrowings not based on Eurodollar rates, including swingline borrowings, bear interest at the highest of (1) the federal funds effective rate plus 0.5%, (2) the prime commercial lending rate of the administrative agent, and (3) the daily LIBOR for a one-month interest period plus 1.0%, plus in each case a margin ranging from 0.0% to 0.5%. The syndicated credit agreement contains a provision that will result in interest rates being based upon a replacement index for LIBOR, if necessary. It is not clear how the interest rate will be calculated using the replacement index. The phase-out of LIBOR is not expected to have a material adverse effect on our cost of borrowing due to the amounts typically outstanding under the syndicated credit agreement. Additionally, we are also responsible for customary unused commitment fees, an administrative agent fee, and letter of credit fees.

The credit agreement contains customary conditions to borrowing or the issuance of letters of credit, representations and warranties, and covenants. The credit agreement obligates us to maintain a debt to capitalization ratio of no more than 0.85 to 1.00 and to maintain a margins for interest ratio of no less than 1.10 times interest charges (calculated in accordance with our Indenture). Obligations under the credit agreement may be accelerated following, among other things:

- our failure to timely pay any principal and interest due under the credit facility;
- a breach by us of our representations and warranties in the credit agreement or related documents;
- a breach of a covenant contained in the credit agreement, which, in some cases we are given an opportunity to cure and, in certain cases, includes a debt to capitalization financial covenant;
- failure to pay, when due, other indebtedness above a specified amount;
- an unsatisfied judgment above specified amounts;
- bankruptcy or insolvency events relating to us;
- invalidity of the credit agreement and related loan documentation or our assertion of invalidity; and
- a failure by our member distribution cooperatives to pay amounts in excess of an agreed threshold owing to us beyond a specified cure period.

We are in compliance with the credit agreement.

We maintain a program which allows our member distribution cooperatives to prepay or extend payment on their monthly power bills. Under this program, we pay interest on prepayment balances at a blended investment and short-term borrowing rate, and we charge interest on extended payment balances at a blended prepayment and short-term borrowing rate. Amounts prepaid by our member distribution cooperatives are included in accounts payable–members and as of December 31, 2019 and 2018, were $15.3 million and $42.1 million, respectively. Amounts extended to our member distribution cooperatives are included in accounts receivable–members and as of December 31, 2019 and 2018, were $20.5 million and $6.4 million, respectively.

NOTE 13—Employee Benefit Plans

Substantially all of our employees participate in the NRECA Retirement Security Plan, a noncontributory, defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the IRC. It is considered a multi-employer plan under accounting standards. The legal name of the plan is the NRECA Retirement Security Plan; the employer identification number is 53–0116145, and the plan number is 333. Plan information is available publicly through the annual Form 5500, including attachments. The plan year is January 1 through December 31. In total, the NRECA Retirement Security Plan was over 80% funded on January 1, 2019 and 2018, based on the PPA funding target and PPA actuarial value of assets on those dates. The cost of the plan is funded annually by payments to NRECA to ensure that annuities in amounts established by the plan will be available to individual participants upon their retirement. In 2013, we elected to make a voluntary prepayment of $7.7 million to the NRECA Retirement Security Plan and recorded this payment as a regulatory asset which will be fully amortized in 2022. There has been no funding improvement plan or rehabilitation plan implemented nor is one pending, and we did not pay a surcharge to the plan for 2019.

We also participate in the Deferred Compensation Pension Restoration Plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the NRECA Retirement Security Plan because of the IRC limitations; participation in this plan was closed to new participants as of January 1, 2015.

Our required contribution to the NRECA Retirement Security Plan and the Deferred Compensation Pension Restoration Plan totaled $3.7 million, $3.4 million, and $3.2 million in 2019, 2018, and 2017, respectively. In each of these years, our contributions represented less than 5% of the total contributions made to the plan by all participating employers.

Beginning in 2019, we adopted the Executive Benefit Restoration Plan, which is intended to provide a supplemental benefit for employees who would have a reduction in their pension benefit from the NRECA Retirement Security Plan because of the IRC limitations. We have recorded a liability of $0.1 million in deferred credits and other liabilities–other.

Pension expense, inclusive of administrative fees, was $4.7 million, $4.2 million, and $4.1 million for 2019, 2018, and 2017, respectively. Pension expense for 2019, 2018, and 2017 includes $0.8 million related to the amortization of the voluntary prepayment regulatory asset.

We have a defined contribution 401(k) retirement plan and we match up to the first 2% of each participant's base salary. Our matching contributions were $0.3 million in 2019, 2018, and 2017.

NOTE 14—Supplemental Cash Flows Information

Cash paid for interest, net of amounts capitalized, in 2019, 2018, and 2017, was $60.3 million, $52.9 million, and $23.8 million, respectively. Cash paid for income taxes was immaterial in 2019, 2018, and 2017. Accrued capital expenditures in 2019, 2018, and 2017 were $69.8 million, $46.9 million, and $23.1 million, respectively.

NOTE 15—Commitments and Contingencies

Environmental

We are subject to federal, state, and local laws and regulations and permits designed to both protect human health and the environment and to regulate the emission, discharge, or release of pollutants into the environment. We believe we are in material compliance with all current requirements of such environmental laws and regulations and permits. However, as with all electric utilities, the operation of our generating units could be affected by future changes in environmental laws and regulations, including new requirements. Capital expenditures and increased operating costs required to comply with any future regulations could be significant.

Insurance

The Price-Anderson Amendments Act of 1988 provides the public up to $14.1 billion of liability protection per nuclear incident, via obligations required of owners of nuclear power plants, and is subject to change every five years for inflation and for the number of licensed reactors. During the second quarter of 2019, the total liability protection per nuclear incident available to all participants in the secondary financial protection program decreased from $14.1 billion to $13.9 billion. This decrease does not impact Virginia Power or our responsibility per active unit under the Price-Anderson Amendments Act of 1988. Owners of nuclear facilities could be assessed up to $138 million for each of their licensed reactors not to exceed $21 million per year per reactor. There is no limit to the number of incidents for which this retrospective premium can be assessed. Virginia Power, the co-owner of North Anna, is responsible for operating North Anna. Under several of the nuclear insurance policies procured by Virginia Power to which we are a party, we are subject to retrospective premium assessments in any policy year in which losses exceed the funds available to the insurance companies.

As a joint owner of North Anna, we are a party to the insurance policies that Virginia Power procures to limit the risk of loss associated with a possible nuclear incident at the station, as well as policies regarding general liability and property coverage. All policies are administered by Virginia Power, which charges us for our proportionate share of the costs.

Our share of the maximum retrospective premium assessments for the coverage assessments described above is estimated to be a maximum of $35.9 million at December 31, 2019.

NOTE 16—Selected Quarterly Financial Data (Unaudited)

A summary of the quarterly results of operations for the years 2019 and 2018 follows. Amounts reflect all adjustments, consisting of only normal recurring accruals, necessary in the opinion of management for a fair statement of the results for the interim periods. Results for the interim periods may fluctuate as a result of weather conditions, changes in rates, and other factors.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
			(in thousands)		
Statement of Operations Data					
2019					
Operating Revenues	$ 240,779	$ 214,985	$ 252,729	$ 224,189	$ 932,682
Operating Margin	17,997	16,338	17,509	20,952	72,796
Net Margin attributable to ODEC (1)	3,212	3,208	3,158	7,376	16,954
2018					
Operating Revenues	$ 228,009	$ 226,652	$ 257,586	$ 220,321	$ 932,568
Operating Margin	9,729	16,492	18,998	18,137	63,356
Net Margin attributable to ODEC	3,263	3,319	3,396	3,301	13,279

(1) The fourth quarter of 2019 includes an equity contribution of $4.3 million.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Effectiveness of Disclosure Controls and Procedures

As of the end of the period covered by this report, our management, including the President and CEO, and the Senior Vice President and CFO, conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and CEO, and the Senior Vice President and CFO, 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 manner. We have established a Disclosure Assessment Committee composed of members of our senior and middle management to assist in this evaluation. No significant changes in our internal controls over financial reporting or in other factors that could significantly affect such controls have occurred during the previous fiscal year.

Management's Annual Report on Internal Control over Financial Reporting

Our management has assessed our internal control over financial reporting as of December 31, 2019, based on criteria for effective internal control over financial reporting described in "2013 Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that as of December 31, 2019, our system of internal control over financial reporting was properly designed and operating effectively based upon the specified criteria. We have not identified any material weaknesses in our internal control over financial reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is composed of policies, procedures, and reports designed to provide reasonable assurance to our management and board of directors that the financial reporting and the preparation of the financial statements for external reporting purposes has been handled in accordance with accounting principles generally accepted in the United States. Internal control over financial reporting includes those policies and procedures that (1) govern records to accurately and fairly reflect the transactions and dispositions of assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable safeguards against or timely detection of material unauthorized acquisition, use, or disposition of our assets.

Changes in Internal Control over Financial Reporting

No material changes in our internal controls over financial reporting or in other factors that could significantly affect such controls have occurred during the past fiscal year.

Inherent Limitations on Internal Control

Inherent limitations exist with respect to the effectiveness of any system of internal control over financial reporting. No control system can provide absolute assurance that all control issues and instances of error or fraud, if any, have been detected. Even the best designed system can only provide reasonable assurance that the objectives of the control system have been met. Because of these inherent limitations, our internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections as to the effectiveness of internal control in future periods are subject to the risk that internal control may not continue to operate at its current effectiveness levels due to changes in personnel or in our operating environment.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors

We are governed by a board of 23 directors, consisting of two representatives from each of our member distribution cooperatives and one representative from TEC. Pursuant to our bylaws, each of our eleven member distribution cooperatives, in good standing, may recommend candidates that meet director qualifications to the nominating committee of our board of directors. At the annual meeting of the members, the nominating committee nominates candidates for election to our board of directors. At least one candidate from each member distribution cooperative must be a director of that member distribution cooperative. Currently and historically, the other candidate from each member distribution cooperative is the chief executive officer of that member distribution cooperative. The candidates for director are elected to our board of directors by a majority vote of the voting delegates from our members. Each member has one voting delegate. We do not control who the member distribution cooperative recommends to the nominating committee. As a result, our board of directors has not developed criteria for the composition of our board, such as diversity, for use in identifying nominees to our board of directors. One director currently serves as a director on behalf of a member distribution cooperative and TEC. Each elected candidate is authorized to represent that member for a renewable term of one year. Our board of directors sets policy and provides direction to our President and CEO. Our board of directors meets approximately 11 times each year.

Information concerning those serving on our board of directors as of December 31, 2019, including principal occupation and employment during the past five years, qualifications, and directorships in public corporations, if any, is listed below.

J. William Andrew, Jr. (66). President and CEO of Delaware Electric Cooperative, Inc. since 2005. Mr. Andrew has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2005.

Paul H. Brown (74). Retired, formerly Vice President of Commercial Lending at Bank of Southside Virginia where he served from 1995 to 2012. Mr. Brown has been a director of ODEC since 2013 and a director of Prince George Electric Cooperative since 2007.

John J. Burke, Jr. (63). Associate broker at Gunther McClary Real Estate since 2004. Mr. Burke has been a director of ODEC since 2016 and a director of Choptank Electric Cooperative, Inc. since 2010.

Darlene H. Carpenter (73). Realtor with Century 21 New Millennium since 2013. Ms. Carpenter has been a director of ODEC since 2009 and a director of Rappahannock Electric Cooperative since 1984.

Earl C. Currin, Jr. (76). Retired, formerly Provost at Southside Community College where he served from 1970 to 2007. Dr. Currin has been a director of ODEC since 2008 and a director of Southside Electric Cooperative since 1986.

E. Garrison Drummond (68). Retired, formerly an insurance agent with Drummond Insurance Agency, Inc. from 1984 to 2017. Mr. Drummond has been a director of ODEC since 2012 and a director of A&N Electric Cooperative since 2002.

Jeffrey S. Edwards (56). President and CEO of Southside Electric Cooperative since 2007. Mr. Edwards has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2007.

Kent D. Farmer (62). President and CEO of Rappahannock Electric Cooperative since 2004. Mr. Farmer has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2004.

Chad N. Fowler (41). Operations manager of Roger Fowler Sales and Service since 2000. Mr. Fowler has been a director of ODEC since 2016 and a director of Community Electric Cooperative since 2007.

Hunter R. Greenlaw, Jr. (74). President of G.L.M.G. General Contractors, a real estate development and general contracting company since 1974. Mr. Greenlaw has been a director of ODEC since 1991 and a director of Northern Neck Electric Cooperative since 1979.

Steven A. Harmon (58). President and CEO of Community Electric Cooperative since 2013. Mr. Harmon has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2013.

Michael W. Hastings (59). President and CEO of Shenandoah Valley Electric Cooperative since 2016. Mr. Hastings was President and CEO of Jo-Carroll Energy, Inc. from 2005 to 2016. Mr. Hastings has been a director of ODEC since 2016.

Bruce A. Henry (74). Owner and Secretary/Treasurer of Delmarva Builders, Inc. since 1981. Mr. Henry has been a director of ODEC since 1993 and a director of Delaware Electric Cooperative, Inc. since 1978.

David J. Jones (71). Owner/operator of Big Fork Farms since 1970. Mr. Jones has been a director of ODEC since 1986 and a director of Mecklenburg Electric Cooperative since 1982.

Michael J. Keyser (43). CEO and General Manager of BARC Electric Cooperative since 2010. Mr. Keyser has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2010.

John C. Lee, Jr. (59). President and CEO of Mecklenburg Electric Cooperative since 2008. Mr. Lee has held executive positions in the utility industry for over a decade and has been a director of ODEC since 2008.

Cary J. Logan, Jr. (40). President and CEO of Prince George Electric Cooperative since April 2019. Mr. Logan served as Vice President of Engineering at Prince George Electric Cooperative from 2015 to March 2019 and as Senior Engineer at South Carolina Electric & Gas Company from 2006 to 2015. Mr. Logan has been a director of ODEC since April 2019.

Micheal E. Malandro (43). President and CEO of Choptank Electric Cooperative, Inc. since April 2019. Mr. Malandro served as President and CEO of Prince George Electric Cooperative from 2015 to March 2019 and as Vice President of Engineering at Prince George Electric Cooperative from 2004 to 2015. Mr. Malandro has been a director of ODEC since 2015.

Robbie F. Marchant (52). Director of Financial Services at Leary Educational Foundation dba Time Ridge School since 2007 and owner of Marchant Properties of Winchester, LLC since 2009. Ms. Marchant has been a director of ODEC since June 2019 and a director of Shenandoah Valley Electric Cooperative since 2011.

Keith L. Swisher (65). Owner/operator of Swisher Valley Farms, LLC since 1976. Mr. Swisher has been a director of ODEC since 2008 and a director of BARC Electric Cooperative since 1981.

Gregory W. White (67). President and CEO of Northern Neck Electric Cooperative since 2005. Mr. White has held executive positions in the utility industry for over two decades and has been a director of ODEC since 2005.

Belvin Williamson, Jr. (56). President and CEO of A&N Electric Cooperative since 2016. Mr. Williamson was Director – Energy Services/Key Accounts at Rappahannock Electric Cooperative from 1998 to 2016. Mr. Williamson has been a director of ODEC since 2016.

Audit Committee Financial Expert

We do not have an audit committee financial expert because of our cooperative governance structure and the resulting experience all of our directors have with matters affecting electric cooperatives in their roles as a chief executive officer or director of one of our member distribution cooperatives. In addition, the audit committee employs the services of accounting and financial consultants as it deems necessary.

Executive Officers

Our President and CEO administers our day-to-day business and affairs. Our executive officers as of December 31, 2019, their respective ages, positions, and relevant business experience are listed below.

Marcus M. Harris (47). President and CEO of ODEC since April 2018. Mr. Harris served as Executive Vice President and Chief Executive Officer at Kansas Electric Power Cooperative from December 2014 to March 2018.

Bryan S. Rogers (51). Senior Vice President and CFO since July 2018. Mr. Rogers joined ODEC in 1996 and has held various accounting positions, including Vice President and Controller from April 2007 to June 2018.

D. Richard Beam (62). Senior Vice President and COO since January 2019. Mr. Beam joined ODEC in 1987 and has held various power supply positions, including Senior Vice President of Power Supply from November 2013 to December 2018.

Micheal L. Hern (64). General Counsel since July 2019, when he joined ODEC. Mr. Hern served as a partner and President Emeritus at LeClairRyan from December 2016 to July 2019 and as President of LeClairRyan from 2000 to December 2016. During this time at LeClairRyan he served as outside general counsel to ODEC.

Kirk D. Johnson (50). Senior Vice President of Member Engagement since February 2019. Mr. Johnson served as Senior Vice President of Government Relations at NRECA from March 2011 to January 2019.

Code of Ethics

We have a code of ethics which applies to all of our employees, including our President and CEO, Senior Vice President and CFO, and Vice President and Controller. A copy of our code of ethics is available without charge by sending a written request to ODEC, Attention: Ms. Allyson B. Pittman, Vice President and Controller, 4201 Dominion Boulevard, Glen Allen, VA 23060.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

General Philosophy

Our compensation philosophy has four objectives:

- attract and retain a qualified, diverse workforce through a competitive compensation program;
- provide equitable and fair compensation;
- support our business strategy; and
- ensure compliance with applicable laws and regulations.

Total Compensation Package

We compensate our President and CEO and other executive officers through the use of a total compensation package, which includes base salary, competitive benefits, and the potential of a bonus. Our President and CEO's base salary is derived from salary data provided by third parties through national compensation surveys. The national compensation survey data includes data from the labor market for positions with similar responsibilities.

Targeted Overall Compensation

Our compensation program utilizes detailed job descriptions for all of our employees including executive officers, with the exception of the President and CEO, as an instrument to establish benchmarked positions. The market compensation information for each position is derived from salary data provided by third parties through national compensation surveys and includes salary data for positions within the determined competitive labor market. Our job descriptions are reviewed annually and include job responsibilities, required knowledge, skills and abilities, and formal education and experience necessary to accomplish the requirements of the position which in turn helps us achieve operational goals. Utilizing this information, our human resources department determines a market-based salary for each position. A third-party consultant, Burton-Fuller Management, reviews the market-based salary data we compiled for reasonableness annually. We have defined market-based salary as approximately the 50th percentile of the market. Another third-party consultant, Intandem LLC, has been engaged to create a performance appraisal instrument for the President and CEO position as well as to design, distribute, and compile market valuation models and reports for the executive officers.

Process

We have a committee of our board of directors, the executive committee, which recommends all compensation for our President and CEO to the entire board of directors. The entire board of directors then approves the compensation arrangements for the President and CEO. Our board of directors has delegated to our President and CEO the authority to establish and adjust compensation for all employees other than himself. The compensation for all other employees, including executive officers other than the President and CEO, is approved by our President and CEO based upon market-based salary data. On an annual basis our board of directors reviews the performance and compensation of our President and CEO, and our President and CEO reviews the performance and compensation of the remaining executive officers.

Base Salaries

We are an electric cooperative and do not have any stock and as a result, we do not have equity-based compensation programs. For this reason, substantially all of our compensation to our executive officers is provided in the form of base salary. We want to provide our executive officers with a level of assured cash compensation in the form of base salary that is commensurate with the duties and responsibilities of their positions. These salaries are determined based on market data for positions with similar responsibilities.

Bonuses

Our practice has been to, on infrequent occasions, award cash bonuses related to a specific event, such as the consummation of a significant transaction. At the discretion of our board of directors, a bonus may be awarded to our President and CEO. At the discretion of our President and CEO, bonuses may be awarded to the other executive officers.

Severance Benefits

We believe that companies should provide reasonable severance benefits to the President and CEO. With respect to our President and CEO, these severance benefits reflect the fact that it may be difficult to find comparable employment within a short period of time. Our President and CEO's contractual rights to amounts following severance are set forth in his employment agreement. See "Employment Agreement" below. Other than our President and CEO, none of our other executive officers have any contractual severance or termination benefits other than what is provided for under the retirement plans in which they participate and any unused vacation.

Plans

Retirement Plans

We participate in the NRECA Retirement Security Plan, a noncontributory, defined benefit pension plan qualified under Section 401 and tax-exempt under Section 501(a) of the IRC. This plan is available to all employees, with limited exceptions, who work at least 1,000 hours per year. It is considered a multi-employer plan under accounting standards. Benefits, which accrue under the plan, are based upon the employee's base annual salary as of November of the previous year.

We also have a defined contribution 401(k) retirement plan that is available to all employees in regular positions. Under the 401(k) plan for 2019, employees could elect to have up to 100% or $19,000, whichever is less, of their salary withheld on a pre-tax basis, subject to Internal Revenue Service limitations, and invested on their behalf. We match up to the first 2% of each participant's base salary. Also, a catch-up contribution is available for participants in the plan once they attain age 50. The maximum catch-up contribution for 2019 was $6,000.

In addition, we have a non-qualified executive deferred compensation plan (the "Deferred Compensation Plan"). Our board of directors, at its discretion, determines who may participate in the plan as well as an annual contribution, if any, up to the maximum amount allowed by IRC regulations. Our board of directors has determined that, beginning in 2019, employees with the title of Vice President and above may participate in this plan. Currently, our President and CEO is the only participant in this plan. We made a $19,000 contribution to the plan for the benefit of our President and CEO in 2019. See "Deferred Compensation Plan" below.

Pension Restoration Plans

We participate in two pension restoration plans. Each plan intends to provide a supplemental benefit for executive officers who would have a reduction in the pension benefit from the NRECA Retirement Security Plan because of IRC limitations. Beginning in 2019, we participate in the Executive Benefit Restoration Plan and our President and CEO, Senior Vice President and CFO, and Senior Vice President of Member Engagement are currently the only participants in this plan. Our Senior Vice President and COO participates in the Deferred Compensation Pension Restoration Plan. Participation in the Deferred Compensation Pension Restoration Plan was closed to new participants as of January 1, 2015.

Perquisites and Other Benefits

Our board of directors reviews the perquisites that our President and CEO receives during contract discussions with him. Mr. Harris was entitled to personal use of a company automobile, which amounted to $1,272 in 2019.

The executive officers participate in our other benefit plans on the same terms as other employees. These plans include the defined benefit pension plan, the 401(k) plan, medical insurance, life insurance and accidental death and dismemberment, long-term disability, medical reimbursement and dependent care flexible spending accounts, health savings account, health club membership, vacation, holiday, and sick leave. Relocation benefits are reimbursed for all employees who transfer to another location at the request or convenience of ODEC in accordance with our relocation policy. We believe these benefits are customary for similar employers.

Change in Control

There is no provision in our President and CEO's employment agreement or any other arrangement with any other executive officers that increases or decreases any amounts payable to him as a result of a change in control.

Summary Compensation Table

The following table sets forth information concerning compensation awarded to, earned by or paid to our executive officers for services rendered to us in all capacities during each of the last three fiscal years. The table also identifies the principal capacity in which each of these executives serves.

SUMMARY COMPENSATION

Name and Principal Position	Year	Salary	Bonus	Change in Pension Value and Non-qualified Deferred Compensation Earnings (1)	All Other Compen-sation (2)	Total
Marcus M. Harris	2019	$ 675,000	$ —	$ 83,835	$ 25,872	$ 784,707
President and CEO	2018	472,875	—	32,701	62,683	568,259
Bryan S. Rogers	2019	316,103	—	41,571	5,600	363,274
Senior Vice President and CFO	2018	246,686	—	124,593	4,912	376,191
D. Richard Beam (3)	2019	337,404	—	55,076	5,600	398,080
Senior Vice President and COO	2018	317,764	—	464,383	5,500	787,647
	2017	309,699	—	390,164	7,320	707,183
Micheal L. Hern (4)	2019	124,615	—	—	—	124,615
General Counsel						
Kirk D. Johnson (5)	2019	279,231	—	86,147	27,139	392,517
Senior Vice President of Member Engagement						

(1) The Change in Pension Value and Non-Qualified Deferred Compensation Earnings column above and the Present Value of Accumulated Benefit in the Pension Benefits table below disclose the aggregate change in the actuarial present value of the NRECA Retirement Security Plan for each named executive officer and for Mr. Harris and Mr. Johnson, also includes benefits under the Executive Benefit Restoration Plan.

(2) See the All Other Compensation table below.

(3) Mr. Beam was promoted to Senior Vice President and COO effective January 1, 2019.

(4) Mr. Hern joined ODEC on July 31, 2019.

(5) Mr. Johnson joined ODEC on February 25, 2019.

The following table sets forth information concerning all other compensation awarded to, earned by, or paid to our executive officers during 2019.

ALL OTHER COMPENSATION

Name	Matching Contributions under 401(k) Plan [1]	Contributions under Deferred Compensation Plan	Perquisites and other personal benefits[2]	Total
Marcus M. Harris	$ 5,600	$ 19,000	$ 1,272	$ 25,872
Bryan S. Rogers	5,600	—	—	5,600
D. Richard Beam	5,600	—	—	5,600
Micheal L. Hern	—	—	—	—
Kirk D. Johnson	—	—	27,139	27,139

(1) Includes contributions made by us to the 401(k) plan. Mr. Hern and Mr. Johnson will become eligible for matching contributions to the 401(k) plan in 2020.

(2) For Mr. Harris, includes the personal use of a company automobile. For Mr. Johnson, includes relocation benefits.

Potential Payments upon Termination or Change in Control

Except for Mr. Harris, none of our executive officers have any contractual termination benefits other than as provided under the retirement plans in which they participate and none of our executive officers have any change in control benefits.

Employment Agreement

Mr. Marcus M. Harris – President and CEO

We have an employment agreement with our President and CEO. We do not have an employment agreement with any of our other executive officers or our Vice President and Controller.

On December 20, 2019, ODEC entered into an employment agreement with Marcus M. Harris, our President and CEO. The commencement date of the agreement is January 1, 2020. The agreement is for the term of three years, with an automatic one-year extension unless Mr. Harris or ODEC gives written notice one year prior to the expiration of the agreement. The agreement provides that he will receive an annual base salary of $775,000, effective as of January 1, 2020. Salary adjustments shall be considered at each year end and shall be awarded at the discretion of the board of directors. In addition to his annual compensation, Mr. Harris is eligible to participate in the Deferred Compensation Plan, and in 2019, ODEC made a contribution of $19,000 to the Deferred Compensation Plan for Mr. Harris. The board of directors also may grant Mr. Harris an annual bonus at its discretion. Mr. Harris is also entitled to participate in all benefit plans available to the employees of ODEC.

Under the agreement, during the contract term, if Mr. Harris voluntarily terminates his employment following material breach by us or we terminate his employment without specified cause, we will pay Mr. Harris compensation at the rate in effect on the date of termination for one additional year, plus medical insurance benefits for one year, with limited exceptions. In addition, Mr. Harris is entitled to receive any benefits that he otherwise would have been entitled to receive including benefits under our 401(k) plan, pension plan, and supplemental retirement plans, although those benefits will not be increased or accelerated, and any unused vacation.

However, if Mr. Harris becomes employed in any capacity during the one-year period immediately following the date of termination, ODEC's obligation to pay Mr. Harris' salary at the rate in effect on the date of termination shall be reduced by the amount of his salary that he receives from his new employer. Also, the medical insurance benefits will cease if he becomes eligible for medical insurance coverage by virtue of his employment with another company.

Based upon a hypothetical termination date of December 31, 2019, in addition to any benefits that he otherwise would have been entitled to receive including benefits under our 401(k) plan, pension plan, supplemental retirement plans, and any unused vacation, Mr. Harris would have been entitled to receive the following:

Annual compensation	$ 675,000
Targeted bonus	—
Medical insurance	20,574
Total	$ 695,574

Under our employment contract with Mr. Harris, "cause" is defined as (1) gross incompetence, insubordination, gross negligence, willful misconduct in office or breach of a material fiduciary duty, which includes a breach of confidentiality; (2) conviction of a felony, a crime of moral turpitude or commission of an act of embezzlement or fraud against ODEC or any subsidiary or affiliate thereof; (3) the President and CEO's material failure to perform a substantial portion of his duties and responsibilities under the employment contract, but only after ODEC provides the President and CEO written notice of such failure and gives him 30 days to remedy the situation; (4) deliberate dishonesty of the President and CEO with respect to ODEC or any of its subsidiaries or affiliates; or (5) a violation of one of ODEC's written policies which, if curable, is not cured within 30 days after written notice of such violation is provided to the President and CEO, or such violation reoccurs after written notice and an opportunity to cure has been provided.

The President and CEO may terminate his employment with or without good reason by written notice to the board of directors effective 60 days after receipt of such notice by the board of directors. If the President and CEO terminates his employment for good reason, then the President and CEO is entitled to the salary specified above in the "without cause" paragraph. The President and CEO will not be required to render any further services. Upon termination of employment by the President and CEO without good reason, the President and CEO is not entitled to further compensation. Under our employment contract with Mr. Harris, "good reason" is defined as ODEC's failure to maintain compensation or ODEC's material breach of any provision of the employment contract, which failure or breach continued for more than 30 days after the date on which the board of directors received such notice.

Other Executive Officers

Based upon a hypothetical termination date of December 31, 2019, Mr. Rogers, Mr. Beam, Mr. Hern, and Mr. Johnson would only be entitled to the benefits accrued under the retirement plans in which they participate, and any unused vacation. See "Plans" above and "Defined Benefit Plans" below for more information as to the benefits that would be paid under the retirement plans in which they participate.

Defined Benefit Plans

The following table lists the estimated values under the NRECA Retirement Security Plan, the Deferred Compensation Pension Restoration Plan, and the Executive Benefit Restoration Plan as of December 31, 2019. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits was limited to $280,000, effective January 1, 2019.

PENSION BENEFITS

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Year
Marcus M. Harris (1)	NRECA Retirement Security Plan	4.00	$ 146,543	$ —
	Executive Benefit Restoration Plan	1.67	57,588	—
Bryan S. Rogers	NRECA Retirement Security Plan	22.33	899,321	—
	Executive Benefit Restoration Plan	22.33	—	—
D. Richard Beam	NRECA Retirement Security Plan	32.33	2,554,739	—
	Deferred Compensation Pension Restoration Plan	32.33	—	275,525
Micheal L. Hern (2)	NRECA Retirement Security Plan	—	—	—
Kirk D. Johnson (3)	NRECA Retirement Security Plan	17.00	772,232	—
	Executive Benefit Restoration Plan	0.92	12,976	—

(1) Mr. Harris participated in the NRECA Retirement Security Plan with a former employer and earned 2.33 years of credited service with the former employer and earned 1.67 years of credited service with ODEC.

(2) Mr. Hern will be eligible to participate in the NRECA Retirement Security Plan after he completes his first 12 months of consecutive employment.

(3) Mr. Johnson participated in the NRECA Retirement Security Plan with a former employer and earned 16.08 years of credited service with his former employer and earned 0.92 years of credited service with ODEC.

The pension benefits indicated above are the estimated amounts payable by the plan, and they are not subject to any deduction for social security or other offset amounts. The participant's annual pension at his or her normal retirement date, currently age 62, is equal to the product of his or her years of benefit service times final average salary times the multiplier in effect during years of benefit service. The multiplier was 1.7% commencing January 1, 1992. The number of years of credited service is as of the end of the current year for each of the named executives. The present value of accumulated benefit is calculated assuming that the executive retires at the normal retirement age per the plan, but using current number of years of credited service, and that he or she receives a lump sum. The lump sum amounts are calculated using the 30-year Treasury rate (3.36% for 2019, and 2.80% for 2018) and the PPA three segment yield rates (3.43%, 4.46%, and 4.88% for 2019, and 2.20%, 3.57%, and 4.24% for 2018) and the required Internal Revenue Service mortality table for lump sum payments (Group Annuity Reserving 1994, projected to 2002, blended 50%/50% for unisex mortality in combination with the 30-year Treasury rates and PPA Retirement Plan 2000 at 2019 combined unisex 50%/50% mortality in combination with the PPA rates). Lump sums at normal retirement age are then discounted to the last day of the appropriate year using these same assumptions shown for the respective stated interest rates.

The Executive Benefit Restoration Plan and the Deferred Compensation Pension Restoration Plan are intended to provide a supplemental benefit for employees who would have had a reduction in their pension benefit because of IRC limitations. During 2019, Mr. Beam reached normal retirement age, 62, under the Deferred Compensation Pension Restoration Plan, and in accordance with the plan received payment for his pension restoration plan benefits as of December 31, 2019. As long as Mr. Beam continues to work for us, he will continue to earn benefit credit and may elect to receive a payment of his pension restoration plan benefit.

Deferred Compensation Plan

In 2006, we adopted the Deferred Compensation Plan, a non-qualified plan, for the purposes of allowing participants to defer their compensation and providing supplemental deferred compensation within the statutory maximums permitted under IRC Section 457(b). Our board of directors has determined that, beginning in 2019, employees with the title of Vice President and above may participate in this plan. Currently, Mr. Harris is the only participant in this plan. Under the Deferred Compensation Plan, annual deferrals cannot exceed the lesser of 100% of Mr. Harris' annual compensation or $18,500 for 2018 and $19,000 for 2019, adjusted by and subject to specified tax laws, during any year in which we are exempt from federal income taxation. Amounts credited to Mr. Harris under the Deferred Compensation Plan will be credited with earnings or losses equal to those made by an investment in one or more funds of a specified regulated investment company designated by him.

The following table sets forth the non-qualified deferred compensation paid to our executive officers in 2019:

NON-QUALIFIED DEFERRED COMPENSATION

Name	Executive Contributions in Last Fiscal Year	Registrant Contributions in Last Fiscal Year (1)	Aggregate Gains/(Losses) in Last Fiscal Year	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last Fiscal Year End (2)
Marcus M. Harris	$ —	$ 19,000	$ 25,130	$ —	$ 125,796
Bryan S. Rogers	—	—	—	—	—
D. Richard Beam	—	—	—	—	—
Micheal L. Hern	—	—	—	—	—
Kirk D. Johnson	—	—	—	—	—

(1) For Mr. Harris, includes a $19,000 ODEC contribution to the Deferred Compensation Plan, which appears in the Summary Compensation table in the "All Other Compensation" column.

(2) For Mr. Harris, includes a balance of $74,486 which was transferred to ODEC from his former employer, and $13,104, which was previously reported as compensation to Mr. Harris in our Summary Compensation Table for fiscal years prior to fiscal year 2019.

Board of Directors Compensation

It is our policy to compensate the members of our board of directors who are not employed by one of our member distribution cooperatives ("outside directors"). During 2019, our outside directors were compensated by a monthly retainer of $3,800 and were also paid for meetings and other official activities at a rate of $500 per day and $250 per partial day and for teleconferences, if such meetings or other official activities occurred outside the normal board of directors meeting dates. All directors are entitled to be reimbursed for out-of-pocket expenses incurred in attending meetings and other official activities. Our directors receive no other compensation from us. We do not provide our directors pension benefits, non-equity incentive plan compensation, or other perquisites and because we are a cooperative, we do not have stock or other equity options. The following table sets forth the compensation we paid to our directors in 2019:

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash	Total
Paul H. Brown	$ 46,350	$ 46,350
John J. Burke, Jr.	47,850	47,850
Darlene H. Carpenter	48,100	48,100
Earl C. Currin, Jr.	45,600	45,600
E. Garrison Drummond	45,600	45,600
Chad N. Fowler	45,850	45,850
Fred C. Garber	22,800	22,800
Hunter R. Greenlaw, Jr.	46,350	46,350
Bruce A. Henry	45,850	45,850
David J. Jones	45,600	45,600
Robbie F. Marchant	26,600	26,600
Keith L. Swisher	45,600	45,600
	$ 512,150	$ 512,150

Compensation Committee Interlocks and Insider Participation

As described above, the executive committee of our board of directors establishes and the full board of directors approves all compensation and awards paid to our President and CEO. Our board of directors has delegated to our President and CEO, the authority to establish and adjust compensation for all employees other than himself. Other than the two exceptions noted below, no member of our board of directors is or previously was an officer or employee of ODEC or is or has engaged in transactions with ODEC. Mr. Gregory W. White was an employee of ODEC from 1990 to 1996 and from 1999 to 2005 when he left his position as Senior Vice President of Power Supply to become the President and Chief Executive Officer of Northern Neck Electric Cooperative, one of our member distribution cooperatives. Mr. John C. Lee, Jr. was an employee of ODEC from 1992 to 2007 when he left his position as Vice President of Member and External Relations to become the President and Chief Executive Officer of Mecklenburg Electric Cooperative, one of our member distribution cooperatives. All of our directors are employees or directors of our member distribution cooperatives.

Under our executive committee charter, the executive committee's duties and responsibilities include (1) recommending all compensation for ODEC's President and CEO to the board of directors for its approval and (2) serving as the compensation committee of the board of directors to review and discuss with management the contents of the Compensation Discussion and Analysis section of the Annual Report on Form 10-K and to recommend to the board of directors inclusion of the Compensation Discussion and Analysis section in the Annual Report on Form 10-K each year.

CEO Pay Ratio

The annual total compensation of Mr. Marcus M. Harris, our President and CEO, was $784,707 in 2019. Based on reasonable estimates, the median annual total compensation of all of our employees, excluding our President and CEO, was $147,237 for 2019. Accordingly, for 2019, the ratio of the total compensation of our President and CEO to the median of the annual total compensation of all of our other employees was 5.3 to 1.

We identified our median employee based on salary earned in 2019 by each individual who was employed by us on November 15, 2019. We annualized the salary of all permanent employees who were not employed through the entire year.

Compensation Committee Report

The executive committee serves as the compensation committee of the board of directors and has reviewed and discussed with the management of ODEC the contents of the Compensation Discussion and Analysis section and, based on such review and discussion, has recommended to the board of directors its inclusion in this Annual Report on Form 10-K.

Kent D. Farmer, Chair
E. Garrison Drummond
Jeffrey S. Edwards
Chad N. Fowler
John C. Lee, Jr.
Keith L. Swisher

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Not Applicable.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Because we are a cooperative, all of our directors are representatives of our members. Our members include our member distribution cooperatives, which are our principal customers, and TEC. Due to the extent of the payments by each member distribution cooperative to us, our directors are not independent based on the definition of “independence” of the New York Stock Exchange.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table presents fees for services provided by Ernst & Young LLP for the two most recent fiscal years. All Audit, Audit-Related, and Tax Fees shown below were pre-approved by the Audit Committee in accordance with its established procedures.

	2019	2018
Audit Fees [1]	$ 358,000	$ 347,000
Audit-Related Fees [2]	25,744	11,675
Tax Fees [3]	10,506	96,452
Total	$ 394,250	$ 455,127

(1) Fees for professional services provided for the audit of our annual financial statements as well as reviews of our quarterly financial statements, accounting consultations on matters addressed during the audit or interim reviews, and SEC filings and offering memorandums including comfort letters, consents, and comment letters.

(2) Fees for professional services which principally include accounting consultations and due diligence services.

(3) Fees for professional services for tax-related advice and compliance.

For fiscal years 2019 and 2018, other than those fees listed above, we did not pay Ernst & Young LLP any fees for any other products or services.

Audit Committee Preapproval Process for the Engagement of Auditors

All audit, tax, and other services to be performed by Ernst & Young LLP for us must be pre-approved by the Audit Committee. The Audit Committee reviews the description of the services and an estimate of the anticipated costs of performing those services. Pre-approval is granted usually at regularly scheduled meetings. During 2019 and 2018, all services performed by Ernst & Young LLP were pre-approved by the Audit Committee in accordance with this policy.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a) The following documents are filed as part of this Form 10-K.

1. Financial Statements

   See Index on page 44

2. Financial Statement Schedules

   Not applicable

3. Exhibits

Exhibits

*3.1 Amended and Restated Articles of Incorporation of Old Dominion Electric Cooperative (filed as exhibit 3.1 to the Registrant's Form 10-Q, File No. 000-50039, filed on November 10, 2015).

*3.2 Bylaws of Old Dominion Electric Cooperative, Amended and Restated as of June 11, 2019, as amended on June 11, 2019 (filed as exhibit 3.0 to the Registrant's Form 8-K, File No. 000-50039, filed on June 13, 2019).

*4.1 Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee (filed as exhibit 4.1 to the Registrant's Form 10-K for the year ended December 31, 2010, File No. 000-50039, on March 16, 2011).

*4.2 First Supplemental Indenture, dated as of April 1, 2011, to the Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee, including the form of the 2011 Series A, B, and C Bonds (filed as exhibit 4.1 to the Registrant's Form 8-K dated April 7, 2011, File No. 000-50039, on April 8, 2011).

*4.3 Second Supplemental Indenture, dated as of June 1, 2013, to the Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee, including the form of the 2013 Series A and B Bond (filed as exhibit 4.1 to the Registrant's Form 8-K dated June 28, 2013, File No. 000-50039, on July 2, 2013).

*4.4 Third Supplemental Indenture, dated as of November 1, 2014, to the Second Amended and Restated Indenture of Mortgage and Deed of Trust, dated as of January 1, 2011, between Old Dominion Electric Cooperative and Branch Banking and Trust Company, as Trustee, including the form of the 2015 Series A and B Bond (filed as exhibit 4.1 to the Registrant's Form 8-K dated January 15, 2014, File No. 000-50039, on January 16, 2015).

*, **10.1 Second Amended and Restated Wholesale Power Contract between Old Dominion Electric Cooperative and A&N Electric Cooperative, dated January 1, 2009 (filed as exhibit 10.2 and 10.3 to the Registrant's Form 10-Q for the quarterly period ended September 30, 2008, File No. 33-46795, filed on November 12, 2008).

*10.2 Nuclear Fuel Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.3 Purchase, Construction and Ownership Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of December 28, 1982, amended and restated October 17, 1983 (filed as exhibit 10.2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.4 Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, dated as of May 31, 1990 (filed as exhibit 10.4 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.5 Amendment No. 1 to the Clover Purchase, Construction and Ownership Agreement between Old Dominion Electric Cooperative and Virginia Electric and Power Company, effective March 12, 1993 (filed as exhibit 10.34 to the Registrant's Form S-1 Registration Statement, File No. 33-61326, filed on April 19, 1993).

*10.6 Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, dated as of May 31, 1990 (filed as exhibit 10.6 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

*10.7 Amendment to the Clover Operating Agreement between Virginia Electric and Power Company and Old Dominion Electric Cooperative, effective January 17, 1995 (filed as exhibit 10.8 to the Registrant's Form 10-K for the year ended December 31, 1994, File No. 33-46795, on March 15, 1995).

*10.8 Mutual Operating Agreement, dated as of May 18, 2005, between Virginia Electric and Power Company and Old Dominion Electric Cooperative (filed as exhibit 10.66 to the Registrant's Form 10-K for the year ended December 31, 2005, File No. 000-50039, on March 21, 2006).

*10.9 Interconnection Agreement between Delmarva Power & Light Company and Old Dominion Electric Cooperative, dated November 30, 1999 (filed as exhibit 10.33 to the Registrant's Form 10-K for the year ended December 31, 2000, File No. 33-46795, on March 19, 2001).

*10.10 First Amended and Restated Credit Agreement, dated as of March 3, 2017, among Old Dominion Electric Cooperative, the lenders party thereto, the Issuing Lenders party thereto, and Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender (filed as exhibit 10.1 to the Registrant's Form 8-K dated March 3, 2017, File No. 000-50039, on March 8, 2017).

*10.11 Nuclear Decommissioning Trust Agreement between Old Dominion Electric Cooperative and SunTrust Bank, (formerly Crestar Bank), dated June 1, 1999 (filed as exhibit 10.8 to the Registrant's Form 10-K for the year ended December 31, 2014, File No. 000-50039, on March 11, 2015).

*†10.12 Employment Agreement, effective January 1, 2020, between Old Dominion Electric Cooperative and Marcus M. Harris and accepted by Marcus M. Harris on December 20, 2019 (filed as Exhibit 10.1 to the Registrant's Form 8-K, File No. 000-50039, on December 23, 2019).

*†10.13 Employment letter, dated June 29, 2018, of Old Dominion Electric Cooperative and agreed and accepted by Bryan S. Rogers (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on July 3, 2018).

*†10.14 Employment letter, dated July 27, 2018, of Old Dominion Electric Cooperative and agreed and accepted by Allyson B. Pittman (filed as exhibit 10.1 to the Registrant's Form 8-K, No. 000-50039, on July 31, 2018).

*†10.15 Employment letter, dated December 4, 2018, of Old Dominion Electric Cooperative and agreed and accepted by Kirk D. Johnson (filed as exhibit 10.15 to the Registrant's Form 10-K for the year ended December 31, 2018. No 000-50039, on March 6, 2019).

*†10.16 Employment letter, dated July 31, 2019, of Old Dominion Electric Cooperative and agreed and accepted by Micheal L. Hern (filed as exhibit 10.1 to the Registrant's Form 10-Q for the Quarterly Period Ended June 30, 2019, No 000-50039, on August 7, 2019).

*†10.17 Executive Deferred Compensation Plan, dated June 30, 2006, adopted on December 18, 2006 (filed as exhibit 10.2 to the Registrant's Form 8-K File No. 000-50039, on December 21, 2006).

*†10.18 Amended and Restated Deferred Compensation Pension Restoration Plan effective January 1, 2015 (filed as exhibit 10.42 to the Registrant's Form 10-K for the year ended December 31, 2014, File No. 000-50039, on March 11, 2015).

†10.19 Executive Benefit Restoration Plan effective April 9, 2019.

*10.20 Lease Agreement between Old Dominion Electric Cooperative and Regional Headquarters, Inc., dated July 29, 1986 (filed as exhibit 10.27 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992).

10.21 Extension Agreement.

21 Subsidiaries of Old Dominion Electric Cooperative (not included because Old Dominion Electric Cooperative's subsidiaries, considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" under Rule 102(w) of Regulation S-X).

31.1 Certification of the Principal Executive Officer pursuant to Rule 13a-14(a)

31.2 Certification of the Principal Financial Officer pursuant to Rule 13a-14(a)

32.1 Certification of the Principal Executive Officer pursuant to 18 U.S.C. § 1350

32.2 Certification of the Principal 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

* Incorporated herein by reference.

** This agreement is substantially similar in all material respects to the wholesale power contracts of our other member distribution cooperatives.

† Indicates management contract or compensatory plan.

ITEM 16. FORM 10-K SUMMARY

None

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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

By: /s/ MARCUS M. HARRIS
Marcus M. Harris
President and Chief Executive Officer

Date: March 11, 2020

Signature	Title
/s/ MARCUS M. HARRIS Marcus M. Harris	President and Chief Executive Officer (Principal executive officer)
/s/ BRYAN S. ROGERS Bryan S. Rogers	Senior Vice President and Chief Financial Officer (Principal financial officer)
/s/ ALLYSON B. PITTMAN Allyson B. Pittman	Vice President and Controller (Principal accounting officer)
/s/ J. WILLIAM ANDREW, JR. J. William Andrew, Jr.	Director
/s/ PAUL H. BROWN Paul H. Brown	Director
/s/ JOHN J. BURKE, JR. John J. Burke, Jr.	Director
/s/ DARLENE H. CARPENTER Darlene H. Carpenter	Director
/s/ EARL C. CURRIN, JR. Earl C. Currin, Jr.	Director
/s/ E. GARRISON DRUMMOND E. Garrison Drummond	Director
/s/ JEFFREY S. EDWARDS Jeffrey S. Edwards	Director
/s/ KENT D. FARMER Kent D. Farmer	Director
/s/ CHAD N. FOWLER Chad N. Fowler	Director
/s/ HUNTER R. GREENLAW, JR. Hunter R. Greenlaw, Jr.	Director

/s/ STEVEN A. HARMON Steven A. Harmon	Director
/s/ MICHAEL W. HASTINGS Michael W. Hastings	Director
/s/ BRUCE A. HENRY Bruce A. Henry	Director
/s/ DAVID J. JONES David J. Jones	Director
/s/ MICHAEL J. KEYSER Michael J. Keyser	Director
/s/ JOHN C. LEE, JR. John C. Lee, Jr.	Director
/s/ CARY J. LOGAN, JR. Cary J. Logan, Jr.	Director
/s/ MICHEAL E. MALANDRO Micheal E. Malandro	Director
/s/ ROBBIE F. MARCHANT Robbie F. Marchant	Director
/s/ KEITH L. SWISHER Keith L. Swisher	Director
/s/ GREGORY W. WHITE Gregory W. White	Director
/s/ BELVIN WILLIAMSON, JR. Belvin Williamson, Jr.	Director

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(d) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT.

ODEC does not solicit proxies from its cooperative members and thus is not required to provide an annual report to its security holders and will not prepare such a report after filing this Form 10-K for fiscal year 2019. Accordingly, ODEC will not file an annual report with the Securities and Exchange Commission.

Exhibit 31.1

CERTIFICATIONS

I, Marcus M. Harris, certify that:

1. I have reviewed this annual report on Form 10-K 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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 annual 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 my 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: March 11, 2020

/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 annual report on Form 10-K 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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 annual 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 my 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: March 11, 2020

/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 Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2019 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: March 11, 2020

/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 Annual Report of Old Dominion Electric Cooperative (the "Company") on Form 10-K for the period ending December 31, 2019 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: March 11, 2020

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