

ODEC
(Old Dominion Electric Cooperative)

Pre-Qualification and Filing Package

1. Name and address of the entity, including a point of contact;

Address:
Old Dominion Electric Cooperative
4201 Dominion Boulevard
Glen Allen, Virginia 23060

Point of Contact

Kevin Miller
Vice President of Engineering
Phone: 804-968-4040
Email: bpezalla@odec.com

2. Technical and engineering qualifications of the entity or its affiliate, partner or parent company;

ODEC has several experienced engineers on staff that oversee construction and maintenance of generation and transmission facilities, including specifying equipment and designing facilities, as well as evaluating submittals by various EPC firms that do the actual construction. ODEC staffs itself with engineers who have worked for at least a decade each in their profession. ODEC has years of experience operating and maintaining generation and transmission assets. Additionally, ODEC can rely on the cumulative experience of its eleven member-owned electric cooperatives, each of which is professionally staffed and experienced in power delivery, using both transmission and distribution assets.

3. Demonstrated experience of the entity or its affiliate, partner or parent company to develop, construct, maintain and operate transmission facilities, including a list or other evidence of transmission facilities previously developed regarding construction, maintenance or operation of transmission facilities both inside and outside the PJM region;

ODEC and its eleven member-owner electric cooperatives combine to form an entity providing power to over 590,000 accounts, using voltages ranging from 12.5kV to 500kV. ODEC owns all or portions of 4 generating stations which it constructed.

Examples of Generation Projects Completed (Year)

- Wildcat Point Generation facility 1090MW, Maryland (2017)
- Clover Power Station 880MW, Virginia (1995-1996)
- Louisa Power Station 504MW, Virginia (2003)
- Marsh Run Power Station 504MW, Virginia (2004)

Since 2008, ODEC has operated, rebuilt, and maintained 110 miles of 69kV transmission facilities in Accomack and Northampton counties on Virginia's eastern shore, including overhead lines, substation equipment, and submarine cables.

Examples of Transmission Projects Completed or Under Construction (Year)

- Proffit Substation, Albemarle County, VA (1992)
- Purdue Delivery Point modifications Accomack County, VA (2002)
- Rock Springs 500 kV switchyard, Cecil County, MD (2001)
- Kendall-Grove 69kV solar interconnection Northampton County, VA (2017)
- Tasley-Kellam line rebuild and substation rearrangements, VA (2012 - 2016).

4. Previous record of the entity or its affiliate, partner or parent company to adhere to construction, maintenance and operating standards;

ODEC and its member owners have owned and operated transmission facilities for many decades. ODEC actively participates in PJM committees and NERC reliability forums to maintain best practices in transmission construction, operations and maintenance. Each of ODEC's member owners operates a system operation center for control of its distribution and non-BES transmission facilities.

ODEC has posted Planning Criteria and Engineering and Construction Standards on the PJM website.

5. Capability of the entity or its affiliate, partner or parent company to adhere to standardized construction, maintenance and operating practices;

ODEC and its member owners have constructed facilities to RUS standards for decades. Additionally, we have years of experience operating and maintaining these electric facilities. ODEC has a long-term contract with Delmarva Power for operation of its 69kV system in Virginia, which is under PJM's control. ODEC contracts with outside engineering and construction firms when necessary to supplement the internal engineering and construction staff. ODEC has a long-term contract with A&N Electric Cooperative to provide local operations and maintenance support for its 69kV facilities in Virginia.

6. Financial statements of the entity or its affiliate, partner or parent company for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of the entity's existence, if shorter, or such other evidence demonstrating an entity's or its affiliates, partner's or parent company's current and expected financial capability acceptable to PJM;

Attached are ODEC's 10K reports for 2019-2021 (recent 3 years) and 10Q for March 2022.

7. Commitment by the entity to execute the Consolidated Transmission Owners Agreement, if the entity becomes a Designated Entity;

As an existing Transmission Owner in PJM, ODEC is already a signatory to the Consolidated Transmission Owners Agreement

8. Evidence demonstrating the ability of the entity or its affiliate, partner or parent company to address and timely remedy failure of facilities;

ODEC has one of the best transmission operating records for reliable delivery of power to its member loads. Please see the attached report of 3-years' worth of System Average Interruption Duration Index (2019 2020 2021 ODEC DP Outages summary) for ODEC member delivery points from all of ODEC's transmission providers serving ODEC load, including ODEC's transmission to our own load.

ODEC maintains spare inventory in ANEC's warehousing facilities to facilitate timely repair of facilities.

9. Description of the experience of the entity or its affiliate, partner or parent company in acquiring rights of way;

ODEC's member owner electric cooperatives have been acquiring rights-of-way for electric service since the 1930's. ODEC acquired the right-of-way for baseline project b1675, and ODEC retains the services of consultants familiar with various permit requirements and legal aspects of land use.

10. Any other supporting information the PJM requires to determine the entity's prequalification status including but not limited to the execution of a Non-Disclosure Agreement to protect sensitive discussions as may occur between proposing entities and PJM.

None requested.

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

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2022

or

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

For the transition period from _____ to _____

Commission file number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE

(Exact name of registrant as specified in its charter)

VIRGINIA

(State or other jurisdiction of
incorporation or organization)

4201 Dominion Boulevard, Glen Allen, Virginia
(Address of principal executive offices)

23-7048405
(I.R.S. employer
identification no.)

23060
(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 whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically 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 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 Rule 12b-2 of the Exchange Act). Yes No

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

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

GLOSSARY OF TERMS

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

<u>Abbreviation or Acronym</u>	<u>Definition</u>
ACES	Alliance for Cooperative Energy Services Power Marketing, LLC
ASU	Accounting Standards Update
Clover	Clover Power Station
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
Louisa	Louisa Power Station
Marsh Run	Marsh Run Power Station
MMBTU	One Million British Thermal Units
MWh	Megawatt hour(s)
North Anna	North Anna Nuclear Power Station
NYMEX	New York Mercantile Exchange
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
TEC	TEC Trading, Inc.
Wildcat Point	Wildcat Point Generation Facility
XBRL	Extensible Business Reporting Language

OLD DOMINION ELECTRIC COOPERATIVE

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OLD DOMINION ELECTRIC COOPERATIVE
PART 1. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2022	December 31, 2021
	(in thousands)	
	(unaudited)	
ASSETS:		
Electric Plant:		
Property, plant, and equipment	\$ 2,544,295	\$ 2,542,407
Less accumulated depreciation	(1,066,404)	(1,049,756)
Net Property, plant, and equipment	1,477,891	1,492,651
Nuclear fuel, at amortized cost	12,045	14,495
Construction work in progress	53,627	48,956
Net Electric Plant	1,543,563	1,556,102
Investments:		
Nuclear decommissioning trust	256,860	276,658
Unrestricted investments and other	7,949	2,361
Total Investments	264,809	279,019
Current Assets:		
Cash and cash equivalents	115,117	107,852
Accounts receivable	17,904	13,821
Accounts receivable—members	53,895	63,037
Fuel, materials, and supplies	70,880	61,808
Deferred energy	46,876	5,005
Prepayments and other	9,074	10,757
Total Current Assets	313,746	262,280
Deferred Charges and Other Assets:		
Regulatory assets	20,942	22,253
Other assets	128,942	55,405
Total Deferred Charges and Other Assets	149,884	77,658
Total Assets	<u>\$ 2,272,002</u>	<u>\$ 2,175,059</u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 467,517	\$ 464,777
Non-controlling interest	5,829	5,831
Total Patronage capital and Non-controlling interest	473,346	470,608
Long-term debt	1,020,870	1,020,759
Total Capitalization	1,494,216	1,491,367
Current Liabilities:		
Long-term debt due within one year	49,041	49,041
Accounts payable	86,278	82,988
Accounts payable—members	80,114	112,742
Accrued expenses	20,194	6,128
Total Current Liabilities	235,627	250,899
Deferred Credits and Other Liabilities:		
Asset retirement obligations	186,264	184,797
Regulatory liabilities	274,246	220,619
Other liabilities	81,649	27,377
Total Deferred Credits and Other Liabilities	542,159	432,793
Total Capitalization and Liabilities	<u>\$ 2,272,002</u>	<u>\$ 2,175,059</u>

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

OLD DOMINION ELECTRIC COOPERATIVE
CONDENSED CONSOLIDATED STATEMENTS OF REVENUES,
EXPENSES, AND PATRONAGE CAPITAL (UNAUDITED)

	Three Months Ended	
	March 31,	
	2022	2021
	(in thousands)	
Operating Revenues	\$ 217,434	\$ 191,117
Operating Expenses:		
Fuel	33,021	39,754
Purchased power	126,363	70,992
Transmission	34,284	31,626
Deferred energy	(41,871)	(15,940)
Operations and maintenance	18,609	16,436
Administrative and general	10,728	10,880
Depreciation and amortization	17,287	17,676
Amortization of regulatory asset/(liability), net	(200)	2,487
Accretion of asset retirement obligations	1,467	1,415
Taxes, other than income taxes	2,308	2,425
Total Operating Expenses	<u>201,996</u>	<u>177,751</u>
Operating Margin	15,438	13,366
Other income (expense), net	(51)	71
Investment income	759	3,406
Interest charges, net	(13,409)	(14,010)
Income taxes	1	2
Net Margin including Non-controlling interest	<u>2,738</u>	<u>2,835</u>
Non-controlling interest	2	5
Net Margin attributable to ODEC	<u>2,740</u>	<u>2,840</u>
Patronage Capital - Beginning of Period	464,777	453,470
Patronage Capital - End of Period	<u>\$ 467,517</u>	<u>\$ 456,310</u>

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

OLD DOMINION ELECTRIC COOPERATIVE
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Three Months Ended	
	March 31,	
	2022	2021
	(in thousands)	
Operating Activities:		
Net Margin including Non-controlling interest	\$ 2,738	\$ 2,835
Adjustments to reconcile net margin to net cash provided by operating activities:		
Depreciation and amortization	17,287	17,676
Other non-cash charges	4,029	4,129
Change in current assets	(2,330)	36,986
Change in deferred energy	(41,871)	(15,940)
Change in current liabilities	(14,682)	2,981
Change in regulatory assets and liabilities	75,479	10,594
Change in deferred charges and other assets and deferred credits and other liabilities	(19,258)	(3,167)
Net Cash Provided by Operating Activities	<u>21,392</u>	<u>56,094</u>
Investing Activities:		
Purchases of held to maturity securities	(5,562)	—
Increase in other investments	(776)	(3,392)
Electric plant additions	(7,789)	(6,758)
Net Cash Used for Investing Activities	<u>(14,127)</u>	<u>(10,150)</u>
Financing Activities:		
Net Cash Used for Financing Activities	—	—
Net Change in Cash and Cash Equivalents	7,265	45,944
Cash and Cash Equivalents - Beginning of Period	107,852	9,288
Cash and Cash Equivalents - End of Period	<u>\$ 115,117</u>	<u>\$ 55,232</u>

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. *General*

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. In the opinion of management, the accompanying unaudited condensed consolidated financial statements contain all adjustments, which include only normal recurring adjustments, necessary for a fair statement of our consolidated financial position as of March 31, 2022, our consolidated results of operations for the three months ended March 31, 2022 and 2021, and cash flows for the three months ended March 31, 2022 and 2021. The consolidated results of operations for the three months ended March 31, 2022, are not necessarily indicative of the results to be expected for the entire year. These financial statements should be read in conjunction with the financial statements and notes thereto included in our 2021 Annual Report on Form 10-K filed with the Securities and Exchange Commission.

The accompanying financial statements reflect the consolidated accounts of Old Dominion Electric Cooperative and TEC. We are a not-for-profit wholesale power supply cooperative, incorporated under the laws of the Commonwealth of Virginia in 1948. We have two classes of members. Our eleven Class A members are customer-owned electric distribution cooperatives engaged in the retail sale of power to member customers located in Virginia, Delaware, and Maryland. Our sole Class B member is TEC, a taxable corporation owned by our member distribution cooperatives. Our board of directors is composed of two representatives from each of the member distribution cooperatives and one representative from TEC. In accordance with Consolidation Accounting, TEC is considered a variable interest entity for which we are the primary beneficiary. We have eliminated all intercompany balances and transactions in consolidation. The assets and liabilities and non-controlling interest of TEC are recorded at carrying value and the consolidated assets were \$5.8 million as of March 31, 2022 and December 31, 2021. The income taxes reported on our Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital relate to the tax provision for TEC. As TEC is wholly-owned by our Class A members, its equity is presented as a non-controlling interest in our consolidated financial statements.

Our rates are set periodically by a formula that was accepted for filing by FERC 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 as prescribed by FERC. In conformity with GAAP, the accounting policies and practices applied by us in the determination of rates are also employed for financial reporting purposes. The preparation of our condensed consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported therein. Actual results could differ from those estimates. We did not have any other comprehensive income for the periods presented.

We are continuing to monitor ways in which the ongoing impact of the COVID-19 pandemic could affect our operations, results of operations, financial condition, and cash flows.

2. *Fair Value Measurements*

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability.

The following tables summarize our financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2022 and December 31, 2021:

	March 31, 2022	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⁾	\$ 82,270	\$ 82,270	\$ —	\$ —
Nuclear decommissioning trust - net asset value ⁽¹⁾⁽²⁾	174,590	—	—	—
Unrestricted investments and other ⁽³⁾	232	—	232	—
Derivatives - gas and power ⁽⁴⁾	113,780	94,293	11,013	8,474
Total Financial Assets	\$ 370,872	\$ 176,563	\$ 11,245	\$ 8,474
Derivatives - gas and power ⁽⁴⁾	\$ 1,801	\$ —	\$ 1,801	\$ —
Total Financial Liabilities	\$ 1,801	\$ —	\$ 1,801	\$ —

	December 31, 2021	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⁾	\$ 89,227	\$ 89,227	\$ —	\$ —
Nuclear decommissioning trust - net asset value ⁽¹⁾⁽²⁾	187,431	—	—	—
Unrestricted investments and other ⁽³⁾	212	—	212	—
Derivatives - gas and power ⁽⁴⁾	50,793	32,078	3,705	15,010
Total Financial Assets	\$ 327,663	\$ 121,305	\$ 3,917	\$ 15,010
Derivatives - gas and power ⁽⁴⁾	\$ 4,291	\$ —	\$ 4,291	\$ —
Total Financial Liabilities	\$ 4,291	\$ —	\$ 4,291	\$ —

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

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

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

⁽⁴⁾ Derivatives - gas and power represent natural gas futures contracts (Level 1 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. Sensitivity in the market price of financial transmission rights could impact the fair value. For additional information about our derivative financial instruments, see Note 1 of the Notes to Consolidated Financial Statements in our 2021 Annual Report on Form 10-K.

3. Derivatives and Hedging

We are exposed to market price risk by purchasing power to supply the power requirements of our member distribution cooperatives that are not met by our owned generation. In addition, the purchase of fuel to operate our generating facilities also exposes us to market price risk. To manage this exposure, we utilize derivative instruments. See Note 1 of the Notes to Consolidated Financial Statements in our 2021 Annual Report on Form 10-K.

Changes in the fair value of our derivative instruments accounted for at fair value are recorded as a regulatory asset or regulatory liability. The change in these accounts is included in the operating activities section of our Condensed Consolidated Statements of Cash Flows.

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

Commodity	Unit of Measure	Quantity	
		As of March 31, 2022	As of December 31, 2021
Natural gas	MMBTU	62,260,000	58,640,000
Purchased power - financial transmission rights	MWh	6,256,711	9,156,789

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

Balance Sheet Location	Fair Value		
	As of March 31, 2022	As of December 31, 2021	
(in thousands)			
Derivatives in an asset position:			
Natural gas futures contracts	Other assets	\$ 105,306	\$ 35,783
Financial transmission rights	Other assets	8,474	15,010
Total derivatives in an asset position		<u>\$ 113,780</u>	<u>\$ 50,793</u>
Derivatives in a liability position:			
Natural gas futures contracts	Other liabilities	\$ 1,801	\$ 4,291
Total derivatives in a liability position		<u>\$ 1,801</u>	<u>\$ 4,291</u>

The Effect of Derivative Instruments on the Condensed Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Three Months Ended March 31, 2022 and 2021

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of March 31,		Location of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income	Amount of Gain (Loss) Reclassified from Regulatory Asset/Liability into Income for the Three Months Ended March 31,	
	2022	2021		2022	2021
	(in thousands)			(in thousands)	
Natural gas futures contracts	\$ 116,238	\$ 3,711	Fuel	\$ 20,422	\$ (4,365)
Purchased power	8,474	88	Purchased power	1,931	3,612
Total	\$ 124,712	\$ 3,799		\$ 22,353	\$ (753)

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

4. Investments

Investments were as follows as of March 31, 2022 and December 31, 2021:

Description	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
March 31, 2022					
Nuclear decommissioning trust ⁽¹⁾					
Debt securities	\$ 85,137	\$ —	\$ (3,285)	\$ 81,852	\$ 81,852
Equity securities	93,280	84,236	(2,926)	174,590	174,590
Cash and other	418	—	—	418	418
Total Nuclear Decommissioning Trust	\$ 178,835	\$ 84,236	\$ (6,211)	\$ 256,860	\$ 256,860
Unrestricted investments					
Government obligations	\$ 5,568	\$ —	\$ (20)	\$ 5,548	\$ 5,568
Total Unrestricted Investments	\$ 5,568	\$ —	\$ (20)	\$ 5,548	\$ 5,568
Other					
Equity securities	\$ 184	\$ 48	\$ —	\$ 232	\$ 232
Non-marketable equity investments	2,149	2,203	—	4,352	2,149
Total Other	\$ 2,333	\$ 2,251	\$ —	\$ 4,584	\$ 2,381
					\$ 264,809
December 31, 2021					
Nuclear decommissioning trust ⁽¹⁾					
Debt securities	\$ 84,701	\$ 4,052	\$ —	\$ 88,753	\$ 88,753
Equity securities	92,916	94,923	(408)	187,431	187,431
Cash and other	474	—	—	474	474
Total Nuclear Decommissioning Trust	\$ 178,091	\$ 98,975	\$ (408)	\$ 276,658	\$ 276,658
Other					
Equity securities	\$ 157	\$ 55	\$ —	\$ 212	\$ 212
Non-marketable equity investments	2,149	2,370	—	4,519	2,149
Total Other	\$ 2,306	\$ 2,425	\$ —	\$ 4,731	\$ 2,361
					\$ 279,019

⁽¹⁾ Investments in the nuclear decommissioning trust are restricted for the use of funding our share of the asset retirement obligations of the future decommissioning of North Anna. See Note 3 of the Notes to Consolidated Financial Statements in our 2021 Annual Report on Form 10-K. Unrealized gains and losses on investments held in the nuclear decommissioning trust are deferred as a regulatory liability or regulatory asset, respectively.

Contractual maturities of debt securities as of March 31, 2022, were as follows:

Description	Less than	1-5 years	5-10 years	More than	Total
	1 year			10 years	
	(in thousands)				
Other ⁽¹⁾	\$ —	\$ —	\$ 81,852	\$ —	\$ 81,852
Held to maturity	5,568	—	—	—	5,568
Total	\$ 5,568	\$ —	\$ 81,852	\$ —	\$ 87,420

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

5. Other

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 totaled \$500 million through March 3, 2022, and totals \$400 million from March 4, 2022 through February 28, 2025. As of March 31, 2022 and December 31, 2021, we had no borrowings and had a \$0.5 million letter of credit outstanding under this facility.

Revenue Recognition

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives 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. 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 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. For the three months ended March 31, 2022 and 2021, we had no sales to TEC and TEC had no sales to third parties.

Our operating revenues for the three months ended March 31, 2022 and 2021, were as follows:

	Three Months Ended March 31,	
	2022	2021
	(in thousands)	
Revenues from sales to:		
Member distribution cooperatives		
Energy revenues	\$ 115,085	\$ 90,834
Renewable energy credits	17	9
Demand revenues	98,565	93,900
Total revenues from sales to member distribution cooperatives	213,667	184,743
Non-members:		
Energy revenues	3,767	6,191
Renewable energy credits	—	183
Total revenues from sales to non-members	3,767	6,374
Total operating revenues	<u>\$ 217,434</u>	<u>\$ 191,117</u>

6. New Accounting Pronouncements

In March 2020, the FASB issued ASU 2020-04 Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The guidance provides temporary optional expedients and exceptions related to contract modifications and hedge accounting to ease entities' financial reporting burdens as the market transitions from the London Interbank Offered Rate and other interbank offered rates to alternative reference rates. The new guidance allows entities to elect not to apply certain modification accounting requirements, if certain criteria are met, to contracts affected by what the guidance calls reference rate reform. An entity that makes this election would consider changes in reference rates and other contract modifications related to reference rate reform to be events that do not require

contract remeasurement at the modification date or reassessment of a previous accounting determination. The ASU notes that changes in contract terms that are made to effect the reference rate reform transition are considered related to the replacement of a reference rate if they are not the result of a business decision that is separate from or in addition to changes to the terms of a contract to effect that transition. The guidance was effective upon issuance and generally can be applied as of March 12, 2020 through December 31, 2022. We are continuing to evaluate the impact of this standard on our financial statements and currently do not anticipate a material impact from adopting this standard.

OLD DOMINION ELECTRIC COOPERATIVE

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Caution Regarding Forward-looking Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations contains forward-looking statements regarding matters that could have an impact on our business, financial condition, and future operations. These statements, based on our expectations and estimates, are not guarantees of future performance and are subject to risks, uncertainties, and other factors. These risks, uncertainties, and other factors include, but are not limited to: general business conditions; demand for energy; federal and state legislative and regulatory actions, and legal and administrative proceedings; the impact of the ongoing COVID-19 pandemic on our business, financial condition, and future operations; changes in and compliance with environmental laws and regulations; general credit and capital market conditions; weather conditions; the cost and availability of commodities used in our industry; disruption due to cybersecurity threats or incidents; and unanticipated changes in operating expenses and capital expenditures. Our actual results may vary materially from those discussed in the forward-looking statements as a result of these and other factors. Any forward-looking statement speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made even if new information becomes available or other events occur in the future.

Critical Accounting Policies

As of March 31, 2022, there have been no significant changes in our critical accounting policies as disclosed in our 2021 Annual Report on Form 10-K. These policies include the accounting for regulated operations, deferred energy, margin stabilization, accounting for asset retirement and environmental obligations, and accounting for derivatives and hedging.

Basis of Presentation

The accompanying financial statements reflect the consolidated accounts of ODEC and TEC. See "Note 1—General" in Notes to Condensed Consolidated Financial Statements in Part 1, Item 1.

Overview

We are a not-for-profit power supply cooperative owned entirely by our eleven Class A member distribution cooperatives and a Class B member, TEC. We supply our member distribution cooperatives' energy and demand requirements through a portfolio of resources including generating facilities, long-term and short-term physically-delivered forward power purchase contracts, and spot market purchases. We also supply the transmission services necessary to deliver this power to our member distribution cooperatives.

Our results from operations for the three months ended March 31, 2022, as compared to the same period in 2021, were primarily impacted by the increase in our total energy rate charged to our member distribution cooperatives, the increase in purchased energy costs, and the under-collection of energy costs.

- Total revenues from sales to our member distribution cooperatives increased 15.7%, primarily due to the increase in energy revenues. Energy revenues increased 26.7%, due to the 20.3% increase in our total energy rate charged to our member distribution cooperatives effective January 1, 2022, and the 5.4% increase in energy sales in MWh to our member distribution cooperatives.
- Purchased power expense, which includes the cost of purchased energy and capacity, increased 78.0%, primarily due to the 77.6% increase in purchased energy costs. Purchased energy costs increased as a result of the 79.2% increase in the average cost of purchased energy.

- Deferred energy expense for the three months ended March 31, 2022, was an under-collection of \$41.9 million. As a result of this under-collection, we implemented an energy rate increase of 6.7%, effective May 1, 2022.

Our financial condition as of March 31, 2022, was primarily impacted by the under-collection of energy costs, and the \$69.5 million increase in the fair value of derivatives related to natural gas due to the increase in the price of natural gas. This increase in the fair value of these derivatives was recorded in other assets and regulatory liabilities. Additionally, this increase allowed us to withdraw cash from our NYMEX margin account, which resulted in an increase in cash and cash equivalents and other liabilities.

COVID-19 Pandemic

We believe our results for the three months ended March 31, 2022, were not materially impacted by the COVID-19 pandemic. We continue to monitor how the pandemic could affect our operations, results of operations, financial condition, and cash flows. See “Risk Factors” in Item 1A in our 2021 Annual Report on Form 10-K.

Factors Affecting Results

For a comprehensive discussion of factors affecting results, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Factors Affecting Results” in Item 7 in our 2021 Annual Report on Form 10-K.

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.

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 of directors. We make these adjustments utilizing Margin Stabilization.

As detailed in the table below, we utilized Margin Stabilization to reduce revenues for the three months ended March 31, 2022.

	Three Months Ended March 31,	
	2022	2021
	(in thousands)	
Margin Stabilization adjustment	\$ 4,601	\$ 8,754

For further discussion of Margin Stabilization, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Margin Stabilization” in Item 7 in our 2021 Annual Report on Form 10-K.

Weather

Weather affects the demand for electricity. Relatively higher or lower temperatures tend to increase the demand for energy to use air conditioning and heating systems, respectively. Mild weather generally reduces the demand because heating and air conditioning systems are operated less. Weather also plays a role in the price of energy through its effects on the market price for fuel, particularly natural gas.

Heating and cooling degree days are measurement tools used to quantify the need to utilize heating or cooling, respectively, for a building. 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 three months ended March 31, 2022, were as follows:

	Three Months Ended March 31,		
	2022	2021	Change
Heating degree days	1,937	1,958	(1.1)%
Cooling degree days	—	—	—

Power Supply Resources

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); diesel-fired distributed generation facilities; and physically-delivered forward power purchase contracts and spot market energy purchases. Our energy supply resources for the three months ended March 31, 2022 and 2021, were as follows:

	Three Months Ended March 31,			
	2022		2021	
	(in MWh and percentages)			
Generated:				
Wildcat Point	838,368	24.6%	534,036	16.1%
North Anna	419,164	12.3	436,693	13.2
Clover	140,726	4.1	185,594	5.6
Louisa	14,655	0.5	71,077	2.1
Marsh Run	31,065	0.9	104,727	3.2
Distributed Generation	327	—	451	—
Total Generated	1,444,305	42.4	1,332,578	40.2
Purchased:				
Other than renewable:				
Long-term and short-term	850,001	24.9	935,169	28.2
Spot market	886,645	26.0	810,898	24.5
Total Other than renewable	1,736,646	50.9	1,746,067	52.7
Renewable ⁽¹⁾	228,734	6.7	237,028	7.1
Total Purchased	1,965,380	57.6	1,983,095	59.8
Total Available Energy	3,409,685	100.0%	3,315,673	100.0%

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

Generating Facilities

Our operating expenses, and consequently our rates charged to our member distribution cooperatives, are significantly affected by the operations of our generating facilities, which are under dispatch direction of PJM. For further discussion of PJM, see “Business—Power Supply Resources—PJM” in Item 1 in our 2021 Annual Report on Form 10-K.

Operational Availability

The operational availability of our owned generating resources for the three months ended March 31, 2022 and 2021, was as follows:

	Three Months Ended March 31,	
	2022	2021
Wildcat Point	98.3%	99.5%
North Anna	85.6	90.0
Clover	66.5	83.9
Louisa	99.9	98.7
Marsh Run	99.9	99.6

Capacity Factor

The output of Wildcat Point, North Anna, and Clover for the three months ended March 31, 2022 and 2021, as a percentage of maximum dependable capacity rating of the facilities, was as follows:

	Three Months Ended March 31,	
	2022	2021
Wildcat Point	39.5%	25.0%
North Anna	88.4	92.2
Clover	15.3	20.1

Results of Operations

Operating Revenues

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives and non-members. Our operating revenues and energy sales in MWh by type of purchaser for the three months ended March 31, 2022 and 2021, were as follows:

	Three Months Ended March 31,	
	2022	2021
(in thousands)		
Revenues from sales to:		
Member distribution cooperatives		
Energy revenues	\$ 115,085	\$ 90,834
Renewable energy credits	17	9
Demand revenues	98,565	93,900
Total revenues from sales to member distribution cooperatives	213,667	184,743
Non-members:		
Energy revenues	3,767	6,191
Renewable energy credits	—	183
Total revenues from sales to non-members	3,767	6,374
Total operating revenues	\$ 217,434	\$ 191,117
Energy sales to:		
(in MWh)		
Member distribution cooperatives	3,305,268	3,136,512
Non-members	89,405	161,000
Total energy sales	3,394,673	3,297,512
Average cost of energy to member distribution cooperatives (per MWh)	\$ 34.82	\$ 28.96
Average total cost to member distribution cooperatives (per MWh)	\$ 64.64	\$ 58.90

Member Distribution Cooperatives

For the three months ended March 31, 2022, total revenues from sales to our member distribution cooperatives increased \$28.9 million, or 15.7%, as compared to the same period in 2021. Energy revenues increased \$24.3 million, or 26.7%, due to the 20.3% increase in our total energy rate, effective January 1, 2022, and the 5.4% increase in energy sales in MWh. Demand revenues increased \$4.7 million, or 5.0%, substantially due to the increase in transmission costs and capacity-related purchased power expense.

The following table summarizes the changes to our total energy rate since 2021, which were implemented to address the differences in our realized as well as projected energy costs:

Date	% Change
January 1, 2021	(15.9)
January 1, 2022	20.3
May 1, 2022	6.7

Operating Expenses

The following is a summary of the components of our operating expenses for the three months ended March 31, 2022 and 2021:

	Three Months Ended March 31,	
	2022	2021
	(in thousands)	
Fuel	\$ 33,021	\$ 39,754
Purchased power	126,363	70,992
Transmission	34,284	31,626
Deferred energy	(41,871)	(15,940)
Operations and maintenance	18,609	16,436
Administrative and general	10,728	10,880
Depreciation and amortization	17,287	17,676
Amortization of regulatory asset/(liability), net	(200)	2,487
Accretion of asset retirement obligations	1,467	1,415
Taxes, other than income taxes	2,308	2,425
Total Operating Expenses	\$ 201,996	\$ 177,751

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 increased \$24.2 million, or 13.6%, for the three months ended March 31, 2022, as compared to the same period in 2021, primarily as a result of the increase in purchased power expense, partially offset by the decrease in deferred energy expense and fuel expense.

- Purchased power expense, which includes the cost of purchased energy and capacity, increased \$55.4 million, or 78.0%, primarily due to the \$53.1 million, or 77.6%, increase in purchased energy costs. Purchased energy costs increased as a result of the 79.2% increase in the average cost of purchased energy.
- Deferred energy expense, which represents the difference between energy revenues and energy expenses, decreased \$25.9 million. For the three months ended March 31, 2022 and 2021, we under-collected \$41.9 million and \$15.9 million, respectively. For further discussion on deferred energy, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies—Deferred Energy” in Item 7 in our 2021 Annual Report on Form 10-K.
- Fuel expense, which includes gains on our natural gas futures contracts, decreased \$6.7 million, or 16.9%, primarily due to the 23.4% decrease in the average cost of fuel, partially offset by the 8.4% increase in generation from our owned facilities.

Other Items

Interest Charges, Net

The primary factors affecting our interest charges, net are issuances of indebtedness, scheduled payments of principal on our indebtedness, interest charges related to our revolving credit facility (including fees), and capitalized interest. The major components of interest charges, net for the three months ended March 31, 2022 and 2021, were as follows:

	Three Months Ended March 31,	
	2022	2021
	(in thousands)	
Interest on long-term debt	\$ (13,339)	\$ (13,973)
Interest on revolving credit facility	(104)	(95)
Other interest	(258)	(130)
Total interest charges	(13,701)	(14,198)
Allowance for borrowed funds used during construction	292	188
Interest charges, net	<u>\$ (13,409)</u>	<u>\$ (14,010)</u>

Net Margin Attributable to ODEC

Net margin attributable to ODEC, which is a function of our total interest charges plus any additional equity contributions approved by our board of directors, was relatively flat for the three months ended March 31, 2022, as compared to the same period in 2021.

Financial Condition

The principal changes in our financial condition from December 31, 2021 to March 31, 2022, were caused by increases in other assets, other liabilities, regulatory liabilities, and deferred energy; and decreases in accounts payable—members and nuclear decommissioning trust.

- Other assets increased \$73.5 million primarily due to the increase in the fair value of derivatives related to natural gas, slightly offset by the \$6.5 million decrease in the fair value of financial transmission rights.
- Other liabilities increased \$54.3 million primarily due to the cash withdrawal from our NYMEX margin account due to the increase in the fair value of derivatives related to natural gas.
- Regulatory liabilities increased \$53.6 million due to the \$75.0 million increase of deferred gains on derivatives, partially offset by the \$20.5 million unrealized loss on the North Anna nuclear decommissioning fund.
- Deferred energy increased \$41.9 million as a result of the under-collection of our energy costs in 2022.
- Accounts payable—members decreased \$32.6 million due to the \$16.9 million decrease in member prepayments, the payment of the \$8.7 million patronage capital retirement, and the \$7.0 million decrease in the amounts owed to our member distribution cooperatives under Margin Stabilization.
- Nuclear decommissioning trust decreased \$19.8 million due to the decrease in the market value of our investments.

Liquidity and Capital Resources

Sources

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

Operations

During the first three months of 2022 and 2021, our operating activities provided cash flows of \$21.4 million and \$56.1 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 totaled \$500 million through March 3, 2022, and totals \$400 million from March 4, 2022 through February 28, 2025. As of March 31, 2022 and December 31, 2021, we had no borrowings and had a \$0.5 million letter of credit outstanding under this facility.

Financings

We fund the portion of our capital expenditures that we are not able to fund from operations through borrowings under our revolving credit facility and 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. We currently have no plans to construct a major new generating facility or issue any additional long-term indebtedness in the near term. We believe our cash from operations and funds available from our revolving credit facility will be sufficient to meet our currently anticipated future operational and capital requirements.

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. Additionally, we have asset retirement obligations in the future that are significantly offset by the nuclear decommissioning trust, which as of March 31, 2022, had a balance of \$256.9 million. Our future contingent obligations primarily relate to power purchase and natural gas arrangements, and we have no off-balance sheet obligations. 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. We currently anticipate that cash from operations and borrowings under our revolving credit facility will be sufficient to meet our liquidity needs for the near term, including planned capital expenditures, decommissioning trust obligations, and our contingent obligations as described above.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

No material changes occurred in our exposure to market risk during the first quarter of 2022.

ITEM 4. CONTROLS AND PROCEDURES

As of the end of the period covered by this report, our management, including the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer, conducted an evaluation of the effectiveness of our disclosure controls and procedures. Based upon that evaluation, the President and Chief Executive Officer, and Senior Vice President and Chief Financial Officer, concluded that our disclosure controls and procedures are effective in ensuring that all material information required to be filed in this report has been made known to them in a timely manner. We have established a Disclosure Assessment Committee comprised of members of our senior and middle management to assist in this evaluation.

There have been no material changes in our internal control over financial reporting or in other factors that could significantly affect such controls during the past fiscal quarter.

OLD DOMINION ELECTRIC COOPERATIVE

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Recovery of Costs from PJM

In the first quarter of 2014, we incurred approximately \$14.9 million of costs related to the dispatch of our combustion turbine facilities for which we were directed by PJM to incur and were subsequently denied reimbursement. Our pursuit of recovery of these costs from PJM before FERC was unsuccessful.

We pursued recovery as a separate breach of an oral contract claim in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. In 2019, PJM removed the matter to United States District Court for the Eastern District of Virginia and filed a motion to dismiss, and we filed a motion to remand the matter to state court. In 2020, the court granted PJM's motion to dismiss and denied our motion to remand the matter to state court. We filed a notice of appeal to the United States Court of Appeals for the Fourth Circuit, oral arguments were held on October 28, 2021, and on January 19, 2022, the court affirmed the denial of our motion to remand the matter back to state court and dismissed the case. On April 18, 2022, we filed a writ of certiorari with the United States Supreme Court. We cannot predict the outcome of this matter and did not record a receivable related to this matter.

Other Matters

Other than the dispute 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 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in "Risk Factors" in Part I, Item 1A in our 2021 Annual Report on Form 10-K, which could affect our business, results of operations, financial condition, and cash flows. The risks described in our Annual Report on Form 10-K are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, results of operations, financial condition, and cash flows.

ITEM 5. OTHER INFORMATION

On May 10, 2022, our board of directors elected Mr. William K. Buchanan as a member of the board of directors, effective May 10, 2022. Mr. Buchanan was recommended to the Nominating Committee by BARC Electric Cooperative to replace Mr. Christopher S. Botulinski. Mr. Buchanan will serve on the Finance, Rate Design, Strategic Electrification, and Strategic Planning Committees.

ITEM 6. EXHIBITS

31.1	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a)
31.2	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a)
32.1	Certification of the Chief Executive Officer pursuant to 18 U.S.C. § 1350
32.2	Certification of the Chief Financial Officer pursuant to 18 U.S.C. § 1350
101.INS	Inline XBRL Instance Document (the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
104	Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

SIGNATURE

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

OLD DOMINION ELECTRIC COOPERATIVE
Registrant

Date: May 10, 2022

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

CERTIFICATIONS

I, Marcus M. Harris, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - (a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
 - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and
 - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2022

/s/ MARCUS M. HARRIS

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

CERTIFICATIONS

I, Bryan S. Rogers, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Old Dominion Electric Cooperative;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;
3. Based on my knowledge, the financial statements, and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:
 - (a) designed such disclosure controls and procedures or caused such disclosure controls to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;
 - (b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and
 - (d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect the registrant's internal control over financial reporting;
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - (a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: May 10, 2022

/s/ BRYAN S. ROGERS

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

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-Q for the period ending March 31, 2022 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: May 10, 2022

/s/ MARCUS M. HARRIS
Marcus M. Harris
President and Chief Executive Officer
(Principal executive officer)

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-Q for the period ending March 31, 2022 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: May 10, 2022

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

Old Dominion Electric Cooperative 2019 Delivery Point Reliability Summary

January 1 thru December 31



This summary covers the 2019 year, and documents customer interruptions due to loss of supplier service to a delivery point. This report uses the IEEE System Average Interruption Duration Index (SAIDI) to benchmark the performance of the supplier utility.

$$\text{SAIDI} = \frac{\text{Sum of All Consumer Interruption Durations}}{\text{Total Number of Consumers Served}}$$

SAIDI measures the minutes of outage experienced by the average consumer during a one-year period.

NOTE: Planned outages to delivery points that do not affect consumers are excluded in the SAIDI calculations.

LONGEST OUTAGE: December 17, 2019, at Pratts transmission delivery point serving Rappahannock EC; Lasted 29 hours 15 minutes, affected 11,518 Consumers, due to a broken First Energy transmission pole.

Worst overall Transmission Reliability for a cooperative member is Rappahannock EC, with a SAIDI of 5 hours, 48 minutes, 5 seconds from First Energy, and a SAIDI of 5 hours, 30 minutes, 35 seconds from Dominion Energy.

Worst overall Distribution Reliability for a cooperative member is Prince George EC, with a SAIDI of 4 hours, 38 minutes, 53 seconds from Dominion Energy.

	Dominion Energy		Delmarva		First Energy		AEP	ODEC	SVEC
	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Transmission SAIDI	Distribution SAIDI
A&N			0:00:00					0:00:00	
BARC	0:00:00	2:29:16				0:00:00			0:00:00
COMMUNITY	0:00:00	2:12:10							
CHOPTANK			0:03:32	0:50:23					
DELAWARE			0:00:00	0:00:00					
MECKLENBURG	0:00:00	0:00:00							
NORTHERN NECK	0:00:00	0:11:57							
PRINCE GEORGE	0:00:00	4:38:53							
RAPPAHANNOCK	5:30:35	1:55:59			5:48:05				
SHENANDOAH VALLEY	0:00:00	2:28:24			0:33:35				
SOUTHSIDE	0:00:00	1:02:03					0:00:00		
ODEC (overall)	2:08:12	1:57:07	0:01:03	0:37:58	3:17:07	0:00:00	0:00:00	0:00:00	0:00:00

Old Dominion Electric Cooperative 2020 Delivery Point Reliability Summary



January 1 thru December 31

Tropical Storm Isaias Outages Included

This summary covers the 2020 year, and documents customer interruptions due to loss of supplier service to a delivery point. This report uses the IEEE System Average Interruption Duration Index (SAIDI) to benchmark the performance of the supplier utility.

$$\text{SAIDI} = \frac{\text{Sum of All Consumer Interruption Durations}}{\text{Total Number of Consumers Served}}$$

SAIDI measures the minutes of outage experienced by the average consumer during a one-year period.

NOTE: Planned outages to delivery points that do not affect consumers are excluded in the SAIDI calculations.

LONGEST OUTAGE: August 4, 2020, at Courtland delivery point serving Community EC; Lasted 41 hours 54 minutes, affected 695 Consumers, due to tornado damage to a Dominion Energy distribution line [during Tropical Storm Isaias].

Worst overall Transmission Reliability for a cooperative member is COMMUNITY EC, with a SAIDI of 2 hours, 52 minutes, 32 seconds from Dominion Energy.

Worst overall Distribution Reliability for a cooperative member is COMMUNITY EC, with a SAIDI of 13 hours, 0 minutes, 33 seconds from Dominion Energy.

	Dominion Energy		Delmarva		First Energy		AEP	ODEC	SVEC
	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Transmission SAIDI	Distribution SAIDI
A&N			0:00:00					0:36:50	
BARC	0:30:33	2:24:15				0:00:00			0:00:00
COMMUNITY	2:52:32	13:00:33							
CHOPTANK			0:09:03	0:00:00					
DELAWARE			0:00:00	0:00:00					
MECKLENBURG	0:00:00	0:00:00							
NORTHERN NECK	0:00:00	1:44:16							
PRINCE GEORGE	0:52:45	7:25:01							
RAPPAHANNOCK	0:23:40	6:18:57			0:00:40				
SHENANDOAH VALLEY	0:13:40	1:33:37			0:00:00				
SOUTHSIDE	0:46:02	0:41:23					0:00:00		
ODEC (overall)	0:26:37	5:00:54	0:02:41	0:00:00	0:00:20	0:00:00	0:00:00	0:36:50	0:00:00

Old Dominion Electric Cooperative 2021 Delivery Point Reliability Summary



January 1 thru December 31

This summary covers the 2021 year, and documents **customer sustained interruptions that last more than five minutes [IEEE 1366] due to loss of supplier service to a delivery point.** This report uses the IEEE System Average Interruption Duration Index (SAIDI) to benchmark the performance of the supplier utility.

$$\text{SAIDI} = \frac{\text{Sum of All Consumer Interruption Durations}}{\text{Total Number of Consumers Served}}$$

SAIDI measures the minutes of outage experienced by the average consumer during a one-year period.

NOTE: Planned outages to delivery points that do not affect consumers are excluded in the SAIDI calculations.

LONGEST OUTAGE: February 13, 2021, at Center Star delivery point serving Southside EC; Lasted 52 hours 10 minutes, affected 1146 consumers, due to multiple ice covered trees, broken poles, and wire down on the Dominion Energy distribution line serving the delivery point during winter snow and ice storm Tabitha.

Worst overall Transmission Reliability for a cooperative member is A&N EC, with a SAIDI of 4 hours, 36 minutes, 18 seconds from ODEC mostly due to one event caused by a Delmarva Power equipment failure.

Worst overall Distribution Reliability for a cooperative member is SOUTHSIDE EC, with a SAIDI of 20 hours, 53 minutes, 10 seconds from Dominion Energy.

	Dominion Energy		Delmarva		First Energy		AEP	ODEC	SVEC
	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Distribution SAIDI	Transmission SAIDI	Transmission SAIDI	Distribution SAIDI
A&N			0:00:00					4:36:18	
BARC	0:00:00	0:56:20				0:00:00			0:00:00
COMMUNITY	0:58:15	1:37:52							
CHOPTANK			0:00:00	0:00:00					
DELAWARE			0:00:00	0:00:00					
MECKLENBURG	0:00:00	0:00:00							
NORTHERN NECK	0:00:00	0:18:02							
PRINCE GEORGE	0:00:00	9:12:29							
RAPPAHANNOCK	0:00:00	1:39:45			0:21:52				
SHENANDOAH VALLEY	0:16:33	2:29:40			0:13:15				
SOUTHSIDE	0:00:00	20:53:10					0:00:00		
ODEC (overall)	0:03:23	4:11:25	0:00:00	0:00:00	0:17:44	0:00:00	0:00:00	4:36:18	0:00:00

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

(State or other jurisdiction of
incorporation or organization)

4201 Dominion Boulevard, Glen Allen, Virginia
(Address of principal executive offices)

23-7048405

(I.R.S. employer
identification no.)

23060
(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	<input type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input checked="" type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
Emerging growth company	<input type="checkbox"/>		

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

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SIGNATURES

GLOSSARY OF TERMS

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

<u>Abbreviation or Acronym</u>	<u>Definition</u>
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

ODEC, We, Our, Us

PJM

PPA

RCRA

REC

RGGI

RPM

RPS

RTO

RUS

S&P

SEPA

SIP

SO₂

SVEC

TEC

VAPCB

VDEQ

Virginia Power

VSCC

Wildcat Point

WOPC

XBRL

Definition

Old Dominion Electric Cooperative

PJM Interconnection, LLC

Pension Protection Act

Resource Conservation and Recovery Act, as amended

Rappahannock Electric Cooperative

Regional Greenhouse Gas Initiative

Reliability Pricing Model

Renewable portfolio standards

Regional transmission organization

U.S. Department of Agriculture Rural Utilities Service

Standard & Poor's Financial Services LLC

Southeastern Power Administration

State Implementation Plan

Sulfur dioxide

Shenandoah Valley Electric Cooperative

TEC Trading, Inc.

Virginia Air Pollution Control Board

Virginia Department of Environmental Quality

Virginia Electric and Power Company

Virginia State Corporation Commission

Wildcat Point Generation Facility

White Oak Power Constructors

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:

<u>Member Distribution Cooperatives</u>	<u>Revenues</u>	
	(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	<u>\$ 898.5</u>	<u>100.0%</u>

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.

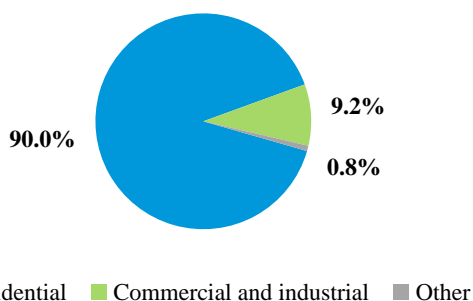
Service Territories and Customers

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.

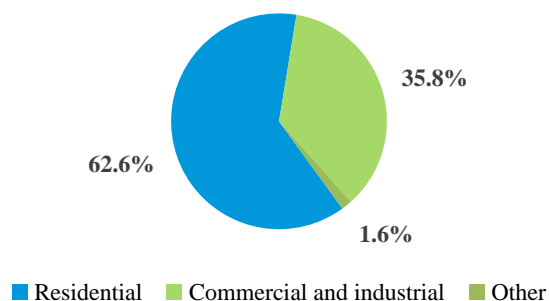
Our member distribution cooperatives' service territories encompass primarily rural, suburban, and recreational areas. Our member distribution cooperatives' customers' requirements for capacity and energy generally are seasonal and increase in winter and summer as home heating and cooling needs increase 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:

Percentage of Customers (Meters)



Percentage of MWh Sales



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 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 SO₂, 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 CO₂ 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 SO₂ 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 SO₂ 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 SO₂ allowances equal to the number of tons of SO₂ they emit into the atmosphere annually. The total number of SO₂ allowances for all facilities is capped, and individual allowances are issued to facilities on the basis of past utilization and other factors. SO₂ 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 SO₂ 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 SO₂ allowances these newer facilities must obtain is typically minimal and can be supplied from any excess SO₂ 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 CO₂ emissions among participating northeastern and Mid-Atlantic States, including Delaware and Maryland. Under the RGGI requirements, we are required to purchase RGGI CO₂ allowances for each ton of CO₂ 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 CO₂ 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 CO₂ Regulation” below.

Virginia CO₂ Regulation

On April 19, 2019, the VAPCB approved a regulation that would reduce and limit CO₂ emissions from large (greater than 25 MW) electric power generating facilities by linking Virginia to the RGGI CO₂ 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 CO₂ emission allowances are to be auctioned, and ODEC will have to purchase allowances for CO₂ emissions from Clover, Louisa, and Marsh Run generation facilities. The legislation requires the VAPCB to establish rules by 2025 to reduce CO₂ 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 CO₂ 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 CO₂ 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 CO₂ from electric power facilities. This regulation could result in increased costs to generate power in Virginia. See "Item 1 Business—Regulation—Virginia CO₂ 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:

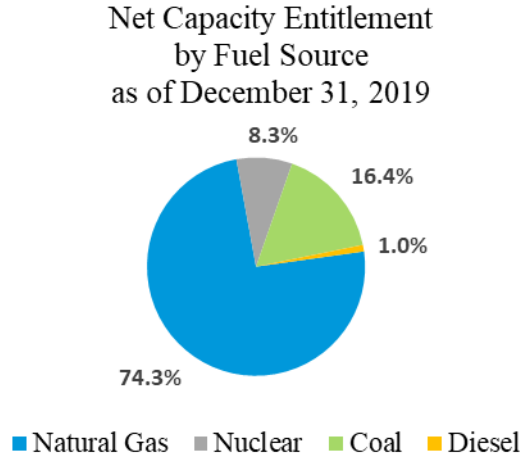
Generating Facility	Ownership Interest	Location	Primary Fuel	Commercial Operation Date	Net Capacity Entitlement ⁽¹⁾
Wildcat Point	100%	Cecil County, Maryland	Natural Gas	04/2018	973 MW
North Anna	11.6%	Louisa County, Virginia	Nuclear	Unit 1 – 06/1978 ⁽²⁾	110 MW
				Unit 2 – 12/1980 ⁽²⁾	110 MW
					<u>220 MW</u>
Clover	50%	Halifax County, Virginia	Coal	Unit 1 – 10/1995	220 MW
				Unit 2 – 03/1996	218 MW
					<u>438 MW</u>
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
					<u>26 MW</u>
Total					<u><u>2,665 MW</u></u>

⁽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	<u>\$2,169,244</u>	<u>\$2,066,901</u>	<u>\$2,209,162</u>	<u>\$2,130,116</u>	<u>\$2,001,599</u>
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	<u>\$1,673,016</u>	<u>\$1,633,372</u>	<u>\$1,703,716</u>	<u>\$1,578,957</u>	<u>\$1,442,898</u>
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	<u>898,471</u>	<u>865,409</u>	<u>731,576</u>
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	<u>34,211</u>	<u>67,159</u>	<u>21,531</u>
Total operating revenues	<u>\$ 932,682</u>	<u>\$ 932,568</u>	<u>\$ 753,107</u>
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	<u>12,429,980</u>	<u>13,510,873</u>	<u>11,878,501</u>
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	<u>\$ (62,773)</u>	<u>\$ (55,222)</u>	<u>\$ (27,040)</u>

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			Projected		
	Year Ended December 31,			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	<u>\$ 153.9</u>	<u>\$ 61.6</u>	<u>\$ 36.3</u>	<u>\$ 111.4</u>	<u>\$ 34.0</u>	<u>\$ 58.8</u>

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	<u>\$ 2,391.7</u>	<u>\$ 296.7</u>	<u>\$ 207.0</u>	<u>\$ 192.5</u>	<u>\$ 1,695.5</u>

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

CONSOLIDATED FINANCIAL STATEMENTS INDEX

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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

Marcus M. Harris
President and Chief Executive Officer

/s/ BRYAN S. ROGERS

Bryan S. Rogers
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	<u>1,657,088</u>	<u>1,639,896</u>
Investments:		
Nuclear decommissioning trust	211,108	173,951
Unrestricted investments and other	5,380	8,066
Total Investments	<u>216,488</u>	<u>182,017</u>
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	<u>211,639</u>	<u>201,909</u>
Deferred Charges and Other Assets:		
Regulatory assets	57,742	38,016
Other	26,287	5,063
Total Deferred Charges and Other Assets	<u>84,029</u>	<u>43,079</u>
Total Assets	<u>\$2,169,244</u>	<u>\$2,066,901</u>
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	<u>1,185,067</u>	<u>1,158,141</u>
Total Capitalization	<u>1,632,224</u>	<u>1,592,580</u>
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	<u>221,362</u>	<u>255,538</u>
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	<u>315,658</u>	<u>218,783</u>
Total Capitalization and Liabilities	<u>\$2,169,244</u>	<u>\$2,066,901</u>

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**

	<u>2019</u>	<u>2018</u>	<u>2017</u>
		(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	<u>859,886</u>	<u>869,212</u>	<u>713,133</u>
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	<u>\$ 441,311</u>	<u>\$ 428,663</u>	<u>\$ 415,384</u>

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**

	<u>2019</u>	<u>2018</u>	<u>2017</u>
	(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	<u>18,011</u>	<u>58,184</u>	<u>56,498</u>
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	<u>(39,441)</u>	<u>153,759</u>	<u>(166,077)</u>
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	<u>26,151</u>	<u>(193,049)</u>	<u>110,717</u>
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	<u>\$ 27,699</u>	<u>\$ 22,978</u>	<u>\$ 4,084</u>

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO 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	<u>\$830,343</u>	<u>\$ 218,483</u>	<u>\$ 318,471</u>	<u>\$ 220,673</u>	<u>\$ 69,118</u>	<u>\$1,657,088</u>

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	<u>\$825,342</u>	<u>\$ 185,013</u>	<u>\$ 326,691</u>	<u>\$ 232,093</u>	<u>\$ 70,757</u>	<u>\$1,639,896</u>

⁽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	<u>\$ 173,669</u>

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:

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

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	<u>\$ 898.5</u>	<u>\$ 865.4</u>	<u>\$ 731.6</u>

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:

Commodity	Unit of Measure	Quantity	
		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:

Balance Sheet Location	Fair Value		
	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		<u>\$ 1,013</u>	<u>\$ 784</u>
Derivatives in a liability position:			
Natural gas futures contracts	Deferred credits and other liabilities-other	\$ 24,125	\$ 591
Total derivatives in a liability position		<u>\$ 24,125</u>	<u>\$ 591</u>

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,		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		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	<u>\$ 145,482</u>	<u>\$ 68,183</u>	<u>\$ (2,557)</u>	<u>\$ 211,108</u>	<u>\$ 211,108</u>
Unrestricted investments					
Government obligations	\$ 2,869	\$ 4	\$ —	\$ 2,873	\$ 2,869
Debt securities	240	—	—	240	240
Total Unrestricted Investments	<u>\$ 3,109</u>	<u>\$ 4</u>	<u>\$ —</u>	<u>\$ 3,113</u>	<u>\$ 3,109</u>
Other					
Equity securities	\$ 110	\$ 15	\$ —	\$ 125	\$ 125
Non-marketable equity investments	2,146	2,176	—	4,322	2,146
Total Other	<u>\$ 2,256</u>	<u>\$ 2,191</u>	<u>\$ —</u>	<u>\$ 4,447</u>	<u>\$ 2,271</u>
					<u>\$ 216,488</u>
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	<u>\$ 139,649</u>	<u>\$ 41,566</u>	<u>\$ (7,264)</u>	<u>\$ 173,951</u>	<u>\$ 173,951</u>
Unrestricted investments					
Government obligations	\$ 4,935	\$ —	\$ (5)	\$ 4,930	\$ 4,935
Debt securities	595	—	(2)	593	595
Total Unrestricted Investments	<u>\$ 5,530</u>	<u>\$ —</u>	<u>\$ (7)</u>	<u>\$ 5,523</u>	<u>\$ 5,530</u>
Other					
Equity securities	\$ 347	\$ 46	\$ —	\$ 393	\$ 393
Non-marketable equity investments	2,143	2,080	—	4,223	2,143
Total Other	<u>\$ 2,490</u>	<u>\$ 2,126</u>	<u>\$ —</u>	<u>\$ 4,616</u>	<u>\$ 2,536</u>
					<u>\$ 182,017</u>

⁽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:

<u>Description</u>	<u>Less than</u>	<u>1-5 years</u>	<u>5-10 years</u>	<u>More than</u>	<u>Total</u>
	<u>1 year</u>			<u>10 years</u>	
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:

	<u>December 31,</u>	
	<u>2019</u>	<u>2018</u>
	(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	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
	<u>1,164,870</u>	<u>1,205,662</u>
Debt issuance costs	(6,211)	(6,729)
Current maturities	(40,792)	(40,792)
	<u>\$ 1,117,867</u>	<u>\$ 1,158,141</u>

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
	<u>\$ 1,164,870</u>

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 employees.

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.

	<u>First Quarter</u>	<u>Second Quarter</u>	<u>Third Quarter</u>	<u>Fourth Quarter</u>	<u>Total</u>
	(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 Compensation ⁽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	<u>20,574</u>
Total	<u>\$ 695,574</u>

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
	<u>\$ 512,150</u>	<u>\$ 512,150</u>

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	<u>\$ 394,250</u>	<u>\$ 455,127</u>

(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

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

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

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)

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)

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)

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)

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, 2020

OR

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

For the transition period from _____ to _____
Commission file number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE

(Exact name of Registrant as specified in its charter)

VIRGINIA

(State or other jurisdiction of
incorporation or organization)

4201 Dominion Boulevard, Glen Allen, Virginia
(Address of principal executive offices)

23-7048405
(I.R.S. employer
identification no.)

23060
(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	<input type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input checked="" type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
Emerging growth company	<input type="checkbox"/>		

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

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

2020 ANNUAL REPORT ON FORM 10-K

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SIGNATURES

GLOSSARY OF TERMS

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

<u>Abbreviation or Acronym</u>	<u>Definition</u>
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	United States Department of Energy
EPA	Environmental Protection Agency
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
Mitsubishi	Mitsubishi Hitachi Power Systems Americas, Inc.
Moody's	Moody's Investors Service
MPSC	Maryland Public Service Commission
MW	Megawatt(s)
MWh	Megawatt hour(s)
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	United States Nuclear Regulatory Commission
NRECA	National Rural Electric Cooperative Association
NYMEX	New York Mercantile Exchange
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
PPA	Pension Protection Act
REC	Rappahannock Electric Cooperative
RGGI	Regional Greenhouse Gas Initiative

Abbreviation or Acronym

Rock Springs
RPM
RPS
RTO
RUS
S&P
SEPA
SO₂
SVEC
TEC
VAPCB
Virginia Power
VSCC
Wildcat Point
WOPC
XBRL

Definition

Rock Springs Power Station
Reliability Pricing Model
Renewable portfolio standards
Regional transmission organization
United States Department of Agriculture Rural Utilities Service
Standard & Poor's Financial Services LLC
Southeastern Power Administration
Sulfur dioxide
Shenandoah Valley Electric Cooperative
TEC Trading, Inc.
Virginia Air Pollution Control Board
Virginia Electric and Power Company
Virginia State Corporation Commission
Wildcat Point Generation Facility
White Oak Power Constructors
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 wholesale 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 2020.

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).

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 2020 were as follows:

Member Distribution Cooperatives	Revenues	
	(in millions)	
Rappahannock Electric Cooperative	\$ 237.6	30.8%
Shenandoah Valley Electric Cooperative	144.5	18.7
Delaware Electric Cooperative, Inc.	110.0	14.3
Choptank Electric Cooperative, Inc.	73.7	9.6
Southside Electric Cooperative	56.9	7.4
A&N Electric Cooperative	48.0	6.2
Mecklenburg Electric Cooperative	36.8	4.8
Prince George Electric Cooperative	22.9	3.0
Northern Neck Electric Cooperative	20.2	2.6
Community Electric Cooperative	11.0	1.4
BARC Electric Cooperative	9.2	1.2
Total	\$ 770.8	100.0%

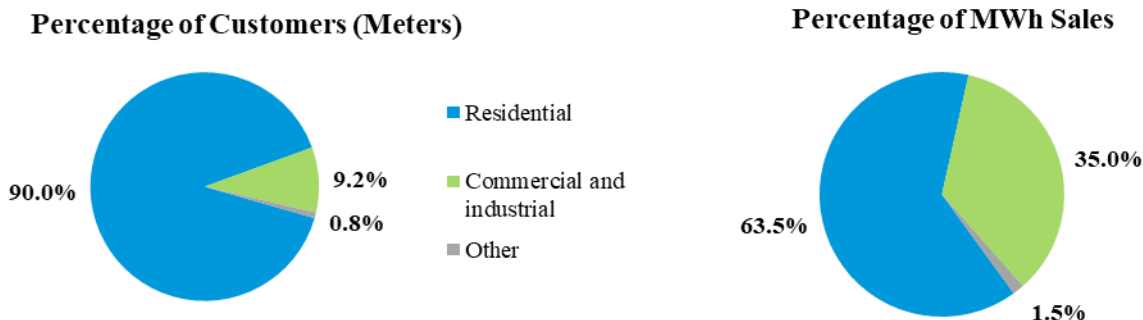
In 2020, there was no individual customer of any of our member distribution cooperatives that constituted 1% or more of our revenues from our member distribution cooperatives.

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 2020 totaled approximately 11,500,000 MWh. These sales were divided by customer class as follows:



From 2015 through 2020, our eleven member distribution cooperatives experienced a compound annual growth rate of 1.9% in the number of customers (meters) and energy sales measured in MWh was relatively flat.

Our eleven member distribution cooperatives' average number of customers per mile of energized line has been relatively unchanged from 2015 to 2020 at approximately 9.5 customers per mile. System densities of our member distribution cooperatives in 2020 ranged from 6.3 customers per mile in the service territory of BARC Electric Cooperative to 14.6 customers per mile in the service territory of A&N Electric Cooperative. In 2020, 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 less than 3% of our member distribution cooperatives' total energy requirements in 2020.

There are two additional limited exceptions to the all-requirements nature of the contracts. One exception permits each of our member distribution cooperatives 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, 2020, none of our member distribution cooperatives had utilized this latter exception.

If all of our member distribution cooperatives elected to fully 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
2018	107
2019	108
2020	111

As of January 1, 2021, the cumulative removal of load requirements under this exception was approximately 140 MW. 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.

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.

Our Delaware and Maryland member distribution cooperatives are not regulated by their respective public service commissions, including with respect to wholesale power costs which are a pass-through to their customers.

We are not subject to any RPS; however, DEC has committed to comply with the Delaware RPS even though it is not required by law to do so, which it meets 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, 2021, 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, one 5 MW customer of one of our member distribution cooperatives has elected to choose an alternate supplier under this provision. Retail choice is also available to any Virginia customer whose noncoincident peak demand exceeds 90 MW. Additionally, all Virginia retail customers may 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, 2020, 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. In recent years, we have had no sales to TEC and TEC has had no sales to third parties. Additionally, we have a separate contract under which we may purchase natural gas from TEC; however, we have not purchased natural gas from TEC in recent years. 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,					
	2020		2019		2018	
	(in MWh and percentages)					
Generated:						
Wildcat Point ⁽¹⁾	3,030,617	24.5%	3,400,633	27.2%	3,126,313	23.0%
North Anna	1,832,792	14.8	1,777,573	14.2	1,855,680	13.7
Clover	620,324	5.0	640,119	5.1	1,437,719	10.6
Louisa	360,984	3.0	494,283	4.0	544,390	4.0
Marsh Run	582,648	4.7	716,390	5.8	572,434	4.2
Rock Springs ⁽²⁾	—	—	—	—	212,957	1.6
Distributed Generation	2,536	—	2,327	—	1,434	—
Total Generated	<u>6,429,901</u>	<u>52.0</u>	<u>7,031,325</u>	<u>56.3</u>	<u>7,750,927</u>	<u>57.1</u>
Purchased:						
Other than renewable:						
Long-term and short-term	2,715,944	22.0	2,665,167	21.3	2,924,477	21.5
Spot market	2,438,563	19.7	2,047,654	16.4	2,091,063	15.4
Total Other than renewable	<u>5,154,507</u>	<u>41.7</u>	<u>4,712,821</u>	<u>37.7</u>	<u>5,015,540</u>	<u>36.9</u>
Renewable ⁽³⁾	784,224	6.3	752,405	6.0	808,052	6.0
Total Purchased	<u>5,938,731</u>	<u>48.0</u>	<u>5,465,226</u>	<u>43.7</u>	<u>5,823,592</u>	<u>42.9</u>
Total Available Energy	<u><u>12,368,632</u></u>	<u><u>100.0%</u></u>	<u><u>12,496,551</u></u>	<u><u>100.0%</u></u>	<u><u>13,574,519</u></u>	<u><u>100.0%</u></u>

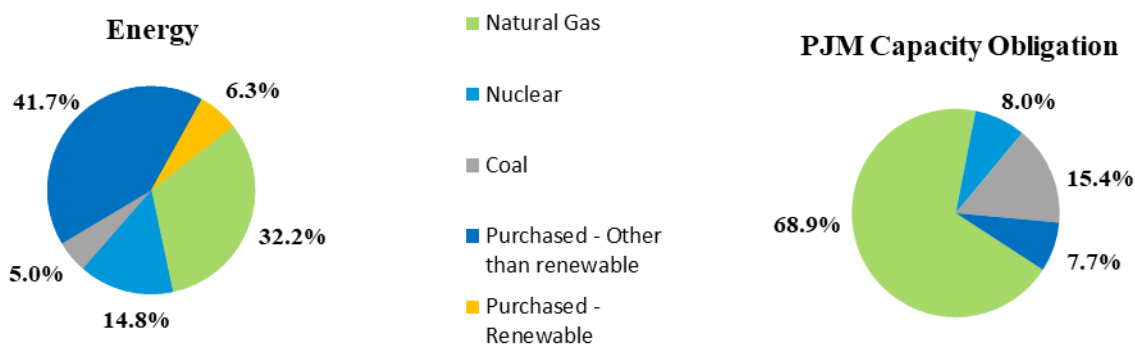
⁽¹⁾ Wildcat Point achieved commercial operation on April 17, 2018.

⁽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 may sell these renewable energy credits to our member distribution cooperatives and non-members.

In 2020, our generating facilities satisfied approximately 92.3% of our weighted average PJM capacity obligation of approximately 2,712 MW. For a description of our generating facilities, see Item 2. In 2020, we satisfied 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.

Our total available energy and total PJM capacity obligation resources by fuel type and purchase type for 2020 are detailed below:



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 “Market Price Risk” in Item 7A.

Power Supply Planning and CO₂ Emission Goals

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. We also evaluate other power supply options including the acquisition, development, or disposition of generating facilities.

As part of our ongoing power supply planning process, on February 3, 2021, we announced a goal to achieve net zero CO₂ emissions by 2050, and set an interim goal to reduce our carbon intensity (pounds of CO₂ emitted per MWh) by 50% (from 2005 levels) by 2030. As of December 31, 2020, we have reduced our carbon intensity by approximately 44% from 2005 levels.

PJM

PJM is an RTO that coordinates the transmission of wholesale electricity in all or parts of 13 states in the eastern United 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 direction 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 “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 for generating facilities and hourly for participants' power requirements.

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. PJM compensates us for the capacity of our generating facilities made available without regard to whether our generating facilities are dispatched. 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. However, capacity auctions were suspended until PJM complied with FERC's ruling on PJM's Minimum Offer Price Rule. The next capacity auction is scheduled for May 2021 for the 2022/2023 delivery year. Subsequent auctions are currently scheduled to be held on an accelerated basis at approximate six-month intervals and the traditional annual auction process will likely resume in May 2024.

The PJM tariff includes a 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, are exposed to significant charges if their generation units do not perform during emergency conditions.

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 "Market Price Risk" in Item 7A.

Renewables

We have power purchase contracts for 300 MW from wind, solar, and landfill gas facilities that are operational. We have entered into additional contracts to purchase power from 85 MW of utility-scale solar and greater than 50 MW of distributed solar projects across our service territories in Virginia, Delaware, and Maryland. We currently anticipate that these projects will become operational between 2021 and 2023. Our contracts for renewables allow us to buy output, including renewable energy credits, from the renewable facilities at predetermined prices. We may 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.

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 “Market Price 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.

Coal

Virginia Power, as operating agent of Clover, has the sole authority and responsibility to procure coal for 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, 2020 and December 31, 2019, based on Clover running at full capacity, there was a 35-day and a 58-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.

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 Virginia Department of Environmental Quality, 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 “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 that could apply to our operations. 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 \$0.2 million and \$0.3 million in 2020 and 2019, 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 SO₂, particulate matter, mercury, and NO_x. Additionally, regulatory programs are in place for new units and for major modifications of existing facilities, and are being proposed for existing units to limit emissions of CO₂ and other GHG. Discussed below are certain standards and regulations under the CAA that impact us.

- Cross-State Air Pollution Rule (“CSAPR”)
 - The rule requires power plants to reduce SO₂ 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 be able to purchase NO_x allowances and a limited number of SO₂ allowances to maintain compliance under the CSAPR program for Wildcat Point, Clover, Louisa, and Marsh Run.
- Acid Rain Program
 - The program requires fossil fuel-fired plants to have SO₂ allowances equal to the number of tons of SO₂ they emit into the atmosphere annually.
 - Clover receives an annual allocation of SO₂ allowances at no cost based on its baseline operations since it is a facility that was built before the Acid Rain Program.
 - Wildcat Point, Louisa, and Marsh Run however, need to obtain allowances under the Acid Rain Program. Because they are primarily gas-fired generating facilities, the number of SO₂ allowances these newer facilities must obtain is typically minimal and can be supplied from any excess SO₂ allowances allocated to Clover.
- Greenhouse Gas Prevention of Significant Deterioration Permitting
 - These regulations set thresholds for GHG emissions that define when permits are required for new sources, as well as modifications to existing industrial facilities.
 - Future renewal of certain permits for Wildcat Point, Clover, Louisa, and Marsh Run may be affected.

Other environmental laws affect our operations and they are discussed below.

Regional Greenhouse Gas Initiative (“RGGI”)

- RGGI, as implemented under the laws of participating northeastern and Mid-Atlantic States, including Virginia, Delaware, and Maryland, provides the framework for and administers a cap-and-trade program to regulate and reduce CO₂ emissions.
- In 2020, the Virginia General Assembly passed legislation, to authorize Virginia to join RGGI in 2021 (see “Virginia Clean Economy Act below).
- We are required to purchase RGGI CO₂ allowances for each ton of CO₂ emitted by Wildcat Point, Clover, Louisa, and Marsh Run.
- We continue to project that there will be an adequate supply of CO₂ allowances available for purchase through RGGI auctions or in the secondary market to support these generating facilities.

Virginia Clean Economy Act

- In 2019, the VAPCB approved a regulation that reduces and limits CO₂ emissions from large (greater than 25 MW) electric power generating facilities.
- Virginia joined RGGI in 2021 and established the RGGI program with an effective starting date of January 1, 2021. (See “RGGI” above.)
- The act requires that the VAPCB establish rules by 2025 to reduce CO₂ 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 act requires that substantially all investor-owned utility generating facilities that emit CO₂ as a by-product of combustion close by December 31, 2045, which would include Clover, which we co-own with Virginia Power, an investor-owned utility. However, if the reliability or security of providing electric service to customers is threatened, a petition may be made by Virginia Power to the VSCC requesting relief from the closure requirement.
- We will continue to be engaged in the development and implementation of the Virginia Clean Economy Act.

Clean Water Act

- The act regulates 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.
- We do not currently expect a significant impact on our facility operations and will continue to follow revised rulemaking requirements to determine potential future impacts related to our facilities.

Resource Conservation and Recovery Act

- This act imposes requirements relating to the disposal of CCRs generated by coal combustion at electric generating facilities.
- These requirements include establishing technical requirements for CCR landfills and surface impoundments, and for monitoring and cleanup of affected soil or groundwater.
- We do not currently expect the operations at Clover to be significantly affected and will continue to monitor the implementation of the CCR rule 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 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.

We anticipate that the most material new regulations are likely to arise under the CAA. Pending regulatory proceedings could result in modifications to certain National Ambient Air Quality Standards, the effect of which can ultimately include stricter emission requirements on new or existing facilities.

There also may be further developments relating to GHG emissions reporting, control, and facility permitting. The Clean Power Plan would have required states to implement specific plans to reduce CO₂ emissions. That regulation was revoked and was replaced with ACE, which was vacated and remanded on January 19, 2021 by the United States Court of Appeals for the District of Columbia Circuit. Continuing efforts to further reduce GHG emissions may lead to some form of replacement of ACE, which could result in limitations on the operations of our generating facilities and/or adversely affect our financial condition, results of operations, or cash flows.

Human Capital

Our success depends upon the skills and collective strengths of all of our employees. We focus on the health, safety, and well-being of our employees. Our workforce is composed of operational staff at our generating facilities and headquarters staff. We are not a party to any collective bargaining agreement. As of March 1, 2021, we had 137 employees, including 50 employees at our generating facilities and 87 employees at our headquarters office. The average tenure of our employees is 11 years.

ITEM 1A. 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 Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, including “Caution Regarding Forward-looking Statements,” and “Notes to Consolidated Financial Statements” in Item 8.

FINANCIAL, MARKET, AND ECONOMIC RISKS

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 2020, 63.8% 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. See “Members—Member Distribution Cooperatives—Wholesale Power Contracts” in Item 1 and “Factors Affecting Results—Formula Rate” in Item 7. 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.

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. When changes are necessary, we apply to FERC to modify our formula rate. As a result, one or more of our member distribution cooperatives, or its customers, could challenge the proposed modifications. Such a challenge likely would not cause us to fail to recover all of our costs and other amounts to be collected under the wholesale power contracts, but it could interfere with our ability to work as effectively as an organization as otherwise would be the case.

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, dispatch, 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 or firing of natural gas and coal; and
- war, acts and threats of terrorism, sabotage, natural disasters, pandemics, and other catastrophic events.

In 2020, we purchased approximately 48.0% 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. Purchases of energy from other suppliers will continue in the future and could 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 Item 7A.

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. We cannot be assured that the defaulting counterparty will compensate us for any damages resulting from the breach of their obligations.

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 future investors and funding sources could decrease.

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.

REGULATORY, LEGISLATIVE, AND ACCOUNTING RISKS

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

PJM, an RTO regulated by FERC, 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 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 direction 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. See "Power Supply Resources—PJM" in Item 1.

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.

ACE, a replacement rule for the Clean Power Plan, regulating carbon emissions relating to existing sources such as power plants, was vacated on January 19, 2021, by the United States Court of Appeals for the District of Columbia Circuit. We are closely monitoring the EPA rulemaking related to ACE, and we currently cannot predict the potential impact on our existing facilities due to the uncertainties and complexities of the regulations.

Virginia joined RGGI in 2021 pursuant to the 2019 regulation that established an emission limitation program to reduce CO₂ from electric power facilities. This regulation is expected to result in increased costs. See “Regulation—Environmental—Virginia Clean Economy Act” in Item 1.

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.

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

As a result of the Energy Policy Act of 2005, as amended, 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 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 increase reported liabilities.

OPERATIONAL RISKS

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 14.8% of our energy requirements in 2020. 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, piping 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.

TECHNOLOGY, CYBERSECURITY RISKS, AND OTHER THREATS

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 the operation or maintenance of 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.

Technological advancements and other changes impacting power requirements of our member distribution cooperatives' customers may alter energy and demand requirements 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.

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 United States 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.

COVID-19 PANDEMIC RISK

Our business and operations, and the operations of our member distribution cooperatives and suppliers, have been and will be impacted by the COVID-19 pandemic and could be similarly impacted by like events in the future.

The outbreak of COVID-19, declared by the World Health Organization to be a pandemic, has spread across the world, including the United States. Because the severity, magnitude, and duration of the COVID-19 pandemic and its economic consequences are uncertain, rapidly changing, and difficult to predict, the ultimate impact on our operations and financial performance cannot be determined at this time. We expect that the longer the period of economic and global supply chain disruptions continue, the greater the risk that there could be a material adverse impact on our operations, results of operations, financial condition, and cash flows.

ODEC is considered an essential service provider and due to this pandemic we previously adjusted and may in the future need to adjust the schedules of our workforce at our owned generating facilities that we operate, specifically Wildcat Point, Louisa, and Marsh Run, and have a contingency plan for staffing at these facilities. We have ownership interests in North Anna and Clover that are operated by Virginia Power, which has taken similar measures. We have developed and implemented procedures to protect our employees from potential exposure to COVID-19 at our facilities, including daily temperature checks, personal protection equipment, and social distancing. Beginning in mid-March 2020, the majority of our headquarters personnel began telecommuting and we plan to continue telecommuting through at least mid-2021. While such practices have not impacted productivity or disrupted our business to date, over a prolonged period of time, such practices could adversely impact our ability to conduct our business in the ordinary course. Further, there can be no assurance that any of these measures will fully protect us from the impact of the COVID-19 pandemic.

On June 8, 2020, the National Bureau of Economic Research announced that the United States was in a recession. Economic conditions, including a significant increase in unemployment and expiration of federal or state support programs, as a result of the COVID-19 pandemic, may make it difficult for some customers of our member distribution cooperatives to pay their power bills. These economic conditions and state government orders prohibiting disconnection of utilities during a state of emergency, could ultimately affect the timeliness of our member distribution cooperatives'

cash flows and potentially the timing of their payments to us. Our member distribution cooperatives' ability to collect their costs from their members may have an impact on our financial condition and cash flows.

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	977 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					2,669 MW

⁽¹⁾ Net capacity entitlement represents (a) the projected maximum dependable capacity in summer conditions for Wildcat Point, (b) an approximation of our entitlement to the maximum dependable capacity in summer conditions for North Anna and Clover, and (c) 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.

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, submitted an application to the NRC in August 2020 for a 20-year operating license extension for North Anna. Virginia Power is responsible for operating and procuring nuclear fuel for North Anna. See "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 "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 operational control of these transmission facilities to PJM and contracted with third parties to monitor 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 the first quarter of 2014, we incurred approximately \$14.9 million of costs related to the dispatch of our combustion turbine facilities for which we were directed by PJM to incur and were subsequently denied reimbursement. Our pursuit of recovery of these costs from PJM before FERC was unsuccessful.

We are pursuing recovery as a separate breach of an oral contract claim in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. In 2019, PJM removed the matter to United States District Court for the Eastern District of Virginia and filed a motion to dismiss, and we filed a motion to remand the matter to state court. In 2020, the court granted PJM's motion to dismiss and denied our motion to remand the matter to state court. We filed a

notice of appeal to the United States Court of Appeals for the Fourth Circuit and oral arguments have been tentatively scheduled for May 2021. We have not recorded a receivable related to this matter.

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, 2020, 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 Item 7.

	Year Ended December 31,				
	2020	2019	2018	2017	2016
	(in thousands, except ratios)				
Statement of Operations Data					
Operating Revenues	\$ 807,704	\$ 932,682	\$ 932,568	\$ 753,107	\$ 877,871
Operating Margin	59,473	72,796	63,356	39,974	45,192
Net Margin attributable to ODEC	12,159	16,954	13,279	26,627	17,637
Margins for Interest Ratio	1.21	1.29	1.26	2.13	1.67
	As of December 31,				
	2020	2019	2018	2017	2016
	(in thousands, except ratios)				
Balance Sheet Data					
Net Electric Plant	\$ 1,608,450	\$ 1,657,088	\$ 1,639,896	\$ 1,703,291	\$ 1,650,918
Total Investments	244,648	216,488	182,017	297,502	270,268
Other Assets	214,546	295,668	244,988	208,369	208,930
Total Assets	<u>\$2,067,644</u>	<u>\$2,169,244</u>	<u>\$2,066,901</u>	<u>\$2,209,162</u>	<u>\$2,130,116</u>
Patronage capital ⁽¹⁾	\$ 453,470	\$ 441,311	\$ 428,663	\$ 415,384	\$ 402,857
Non-controlling interest	5,853	5,846	5,776	5,744	5,725
Long-term debt ⁽²⁾	1,069,324	1,117,867	1,158,141	1,198,396	990,083
Revolving credit facility	—	67,200	—	43,400	152,000
Long-term debt due within one year	49,041	40,792	40,792	40,792	28,292
Total Capitalization and Short-term Debt	<u>\$1,577,688</u>	<u>\$1,673,016</u>	<u>\$1,633,372</u>	<u>\$1,703,716</u>	<u>\$1,578,957</u>
Equity Ratio ⁽³⁾	28.8%	26.5%	26.3%	24.5%	25.6%

⁽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, the impact of the COVID-19 pandemic on our business, financial condition, and future operations, 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 from operations for the year ended December 31, 2020, were primarily impacted by the decreases in our total energy rate and PJM's economic dispatch of our generating facilities, and milder weather.

- Total revenues from sales to our member distribution cooperatives decreased 14.2% as compared to 2019. The decrease in energy revenues was primarily due to the 16.2% decrease in the average cost of energy. Additionally, milder weather contributed to the 4.9% decrease in energy sales in MWh to our member distribution cooperatives.
- Generation from our owned facilities decreased 8.6%, primarily due to PJM's economic dispatch of our generating facilities. The decrease in generation contributed to the 16.5% decrease in fuel expense.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased 24.6%. Purchased energy decreased 23.1% due to the 29.2% decrease in the average cost of purchased energy, partially offset by the 8.7% increase in the volume of purchased energy. The decrease in the average cost of purchased energy was partially due to the expiration of a long-term purchased power contract on May 31, 2020, which was replaced by lower cost purchased energy. The increase in the volume of purchased energy was primarily the result of decreased generation from our owned facilities.
- Transmission expense decreased 19.7% due to changes in PJM charges for network transmission services.

We believe our results for 2020 were not materially impacted by the COVID-19 pandemic. We believe that other factors described above, such as the decrease in our total energy rate and the impact of milder weather, were the primary drivers of our results for 2020. We continue to closely monitor how the pandemic will affect our operations, results of operations, financial condition, and cash flows, and have taken certain actions as a result of the pandemic. See "Factors Affecting Results—COVID-19 Pandemic" below for a more detailed discussion.

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 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 revenues collected from our member distribution cooperatives and our energy expenses. 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 of directors, 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,		
	2020	2019	2018
		(in thousands)	
Margin Stabilization adjustment	\$13,227	\$7,175	\$15,312

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, 2020 and 2019, our share of North Anna's nuclear decommissioning asset retirement obligation totaled \$156.9 million, or 87.6% of our total asset retirement obligations, and \$152.4 million, or 87.8% 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. We are not aware of any events that have occurred since the 2019 study that would materially impact our estimate or that would have required an updated study to be performed in 2020. See "Note 3—Accounting for Asset Retirement and Environmental Obligations" 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, 2020, for our asset retirement obligations related to nuclear decommissioning would have been \$42.9 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 other assets and other liabilities. 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.

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 of directors. 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 recover all of our costs and expenses or determines a change in cost allocation methodology among our member distribution cooperatives is appropriate, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval. On June 26, 2020, we submitted an application to FERC to revise our formula rate for a change in cost allocation methodology of our remaining owned capacity service rate, to be effective January 1, 2021. On August 25, 2020, FERC issued an order accepting our filing with an effective date of January 1, 2021.

COVID-19 Pandemic

Impact on Results of Operations and Financial Condition

For 2020, we do not believe there was a material impact attributable to the COVID-19 pandemic on our results of operations or financial condition.

In 2020, our total revenues decreased \$125.0 million, or 13.4%, as compared to 2019. The decrease was primarily due to the 16.2% decrease in our total energy rate to our member distribution cooperatives, effective January 1, 2020, and the milder weather in 2020.

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives 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 sell excess power and renewable energy credits to non-members at prevailing market prices as control is transferred. In 2020, energy sales in MWh to our member distribution cooperatives decreased 4.9% compared to the prior year. We believe a significant portion of the decrease relates to weather. We engaged a third party to conduct a load impact study and based upon the results of that study determined that less than 1% of the decrease in energy sales in 2020 relates to the COVID-19 pandemic. In addition, the majority of our member distribution cooperatives’ loads are residential, which may be a factor in limiting the impact of the pandemic on our results of operations.

Any decline in our member distribution cooperatives’ power requirements related to the COVID-19 pandemic would result in a reduction of our spot market energy purchases, or excess energy which we would sell to PJM, TEC, or third parties.

The formula rate provides for the recovery of costs, margin requirement, and any additional equity contributions approved by our board of directors, from our member distribution cooperatives. See “Formula Rate” above. We operate on a cost plus specified margin basis; therefore, our net margin is not a function of total revenues. Our margin requirement is equal to 20% of actual interest charges, plus additional equity contributions approved by our board of directors. 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. To date, our member distribution cooperatives' ability to pay their invoices to us has not been impacted. However, our member distribution cooperatives' ability to pay their invoices to us may be impacted by certain factors including high unemployment rates, government actions protecting customers from the disconnection of utilities, and increased commercial or industrial closures/bankruptcies. Under an existing program, our member distribution cooperatives have the option to prepay their invoices from us or to extend payment of their invoices for 60 days. As of December 31, 2020, prepayments totaled \$57.2 million and extensions totaled \$6.5 million.

We increased our cash and cash equivalents balance to \$231.1 million as of March 31, 2020, by borrowing funds under our revolving credit facility due to uncertainties associated with the COVID-19 pandemic. As of December 31, 2020, we had no borrowings outstanding under our revolving credit facility and had a cash and cash equivalents balance of \$9.3 million.

Workforce Considerations

ODEC is considered an essential service provider and due to the COVID-19 pandemic, we adjusted the schedules of our workforce for March through June 2020 at our owned generating facilities that we operate, specifically Wildcat Point, Louisa, and Marsh Run. Although we have transitioned back to pre-pandemic schedules at our generating facilities, we have an ongoing contingency plan for staffing at these facilities. We have developed and implemented procedures to protect our employees from potential exposure to COVID-19 at our facilities, including daily temperature checks, personal protection equipment, and social distancing. Additionally, beginning in mid-March 2020, the majority of our headquarters personnel began telecommuting with no disruption in business operations and will continue telecommuting through at least mid-2021.

The Commonwealth of Virginia has issued workplace regulations related to infectious disease prevention. All employers covered by these regulations must comply with mandatory requirements to protect employees from workplace exposure to COVID-19, and we are subject to these regulations for our operations located in Virginia. We have not had, nor do we anticipate that we will have, a material impact on our operations or costs due to compliance with these regulations.

Ongoing Considerations

We are continuing to monitor ways in which the COVID-19 pandemic could affect our operations, results of operations, financial condition, and cash flows. The extent to which the pandemic will impact us is uncertain and will depend on numerous evolving factors that we may not be able to accurately predict, including the duration and scope of the pandemic and the actions taken in response. See risk factors in Item 1A.

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. Through December 31, 2020, the remaining owned capacity service rate was billed to each of our member distribution cooperatives based on its contribution to the monthly zonal coincident peak. Beginning January 1, 2021, the remaining owned capacity service rate is billed based on the average hourly demand in the prior 12 month period from September 1 to August 31.

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:

	2020	2019	2018
Heating degree days	2,750	3,228	3,145
Cooling degree days	1,361	1,554	1,492

- *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 2020, our generating facilities satisfied approximately 92.3% of our PJM capacity obligation and 52.0% 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 “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 direction 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 “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 “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 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 “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 direction 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,		
	2020	2019	2018
Wildcat Point ⁽¹⁾	90.0%	75.6%	84.2%
North Anna	93.6	91.3	94.9
Clover	69.8	68.9	78.8
Louisa	95.7	94.5	97.2
Marsh Run	92.1	94.2	95.2
Rock Springs ⁽²⁾	—	—	92.0

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

(2) 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,		
	2020	2019	2018
Wildcat Point ⁽¹⁾	35.1%	40.7%	51.8%
North Anna	95.1	92.5	96.5
Clover	16.6	17.1	38.8

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

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 2020 and 2018, one unit at North Anna was off-line for refueling and during 2019, both units at North Anna were 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 “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,		
	2020	2019	2018
	(in thousands)		
Revenues from sales to:			
Member distribution cooperatives			
Energy revenues	\$ 375,714	\$ 471,767	\$ 488,949
Renewable energy credits	33	26	16
Demand revenues	395,067	426,678	376,444
Total revenues from sales to member distribution cooperatives	770,814	898,471	865,409
Non-members			
Energy revenues	31,431	29,483	64,209
Renewable energy credits	5,438	4,672	2,950
Demand revenues	21	56	—
Total revenues from sales to non-members	36,890	34,211	67,159
Total operating revenues	<u>\$ 807,704</u>	<u>\$ 932,682</u>	<u>\$ 932,568</u>
Energy sales to:			
	(in MWh)		
Member distribution cooperatives	10,916,844	11,483,669	11,872,158
Non-members	1,386,307	946,311	1,638,715
Total energy sales	<u>12,303,151</u>	<u>12,429,980</u>	<u>13,510,873</u>
Average cost of energy to member distribution cooperatives (per MWh)	\$ 34.42	\$ 41.08	\$ 41.18
Average total cost to member distribution cooperatives (per MWh)	\$ 70.61	\$ 78.24	\$ 72.89

Member Distribution Cooperatives

In 2020, total revenues from sales to our member distribution cooperatives decreased \$127.7 million, or 14.2%, as compared to 2019. Energy revenues decreased \$96.1 million, or 20.4%, primarily due to the 16.2% decrease in the average cost of energy. Additionally, energy sales in MWh to our member distribution cooperatives decreased 4.9%. Demand revenues decreased \$31.6 million, or 7.4%, primarily due to decreases in transmission expense, capacity-related purchased power expense, and operations and maintenance expense, partially offset by the increase in amortization of regulatory asset/(liability), net.

The following table summarizes the changes to our total energy rate since 2018, which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Rate Change	% Change
January 1, 2018	11.1
April 1, 2018	3.7
January 1, 2019	(1.3)
January 1, 2020	(16.2)
January 1, 2021	(15.9)

Operating Expenses

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

	Year Ended December 31,		
	2020	2019	2018
	(in thousands)		
Fuel	\$ 144,348	\$ 172,921	\$ 187,118
Purchased power	250,546	332,216	397,589
Transmission	128,427	159,995	135,567
Deferred energy	26,660	22,522	(22,400)
Operations and maintenance	61,518	74,647	64,705
Administrative and general	43,023	48,938	45,171
Depreciation and amortization	69,902	68,752	62,503
Amortization of regulatory asset/(liability), net	9,069	(35,056)	(15,853)
Accretion of asset retirement obligations	5,463	5,539	5,319
Taxes, other than income taxes	9,275	9,412	9,493
Total Operating Expenses	\$ 748,231	\$ 859,886	\$ 869,212

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 \$111.7 million, or 13.0%, for 2020 as compared to 2019, primarily as a result of the decreases in purchased power expense, transmission expense, fuel expense, operations and maintenance expense, partially offset by amortization of regulatory asset/(liability), net.

- Purchased power expense, which includes the cost of purchased energy and capacity, decreased \$81.7 million, or 24.6%, due to the \$67.9 million, or 23.1%, decrease in purchased energy, and the \$13.8 million, or 36.0%, decrease in capacity-related purchased power. The average cost of purchased energy decreased 29.2% and the volume of purchased energy increased 8.7%. The decrease in the average cost of purchased energy was partially due to the expiration of a long-term purchased power contract on May 31, 2020, which was replaced by lower cost purchased energy. The increase in the volume of purchased energy was primarily the result of decreased generation from our owned facilities.
- Transmission expense decreased \$31.6 million, or 19.7%, due to changes in PJM charges for network transmission services.
- Fuel expense decreased \$28.6 million, or 16.5%, primarily as a result of the 8.6% decrease in generation from our owned facilities, primarily due to PJM’s economic dispatch.

- Operations and maintenance expense decreased \$13.1 million, or 17.6%, primarily due to the difference in the timing and scope of scheduled outages in 2020 as compared to 2019.
- Amortization of regulatory asset/(liability), net increased \$44.1 million. In 2019, we amortized \$37.7 million of the gain on the sale of Rock Springs and related assets in 2018. See “Factors Affecting Results—Generating Facilities—Sale of Rock Springs Combustion Turbine Facility” above.

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,		
	2020	2019	2018
	(in thousands)		
Interest on long-term debt	\$ (57,831)	\$ (59,931)	\$ (62,032)
Interest on revolving credit facility	(2,078)	(802)	(2,083)
Other interest	(888)	(2,506)	(2,277)
Total interest charges	(60,797)	(63,239)	(66,392)
Allowance for borrowed funds used during construction	491	466	11,170
Interest charges, net	<u>\$ (60,306)</u>	<u>\$ (62,773)</u>	<u>\$ (55,222)</u>

Net Margin Attributable to ODEC

In 2020, 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, decreased \$4.8 million. In 2019, net margin attributable to ODEC included a \$4.3 million equity contribution. See “Factors Affecting Results—Formula Rate” above and “Note 1—Summary of Significant Accounting Policies—Patronage Capital” in Item 8.

Discussion of Results of Operations Comparing 2019 to 2018

For discussion of our financial results comparing 2019 to 2018, see “Results of Operations” in Item 7 of our 2019 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 11, 2020.

Financial Condition

The principal changes in our financial condition from December 31, 2019 to December 31, 2020, were caused by decreases in accounts payable, revolving credit facility, regulatory assets, accounts receivable—members, other liabilities, and other assets; increases in accounts payable—members, nuclear decommissioning trust, and regulatory liabilities; and the change in deferred energy.

- Accounts payable decreased \$86.9 million due to the decrease in construction-related payables primarily as a result of the Wildcat Point settlement and power purchase payables.
- Revolving credit facility decreased \$67.2 million due to repayment of outstanding borrowings under this facility.
- Regulatory assets decreased \$26.6 million primarily due to the change in the deferred net unrealized losses on derivative instruments.
- Accounts receivable—members decreased \$21.4 million due to the \$14.0 million decrease in member distribution cooperatives’ extended payment balances and the \$7.4 million decrease in wholesale power invoices for December 2020 as compared to December 2019.
- Other liabilities decreased \$17.4 million due to the increase in the fair value of our natural gas hedges.

- Other assets decreased \$15.8 million due to decreases in the collateral requirements of our natural gas hedges partially offset by the increase in the fair value of our natural gas hedges.
- Accounts payable—members increased \$43.7 million due to the \$41.9 million increase in member prepayments and the \$6.1 million increase in the Margin Stabilization adjustment as compared to 2019, partially offset by the \$4.3 million decrease related to patronage capital retirement in 2019.
- Nuclear decommissioning trust increased \$31.2 million due to the increase in the market value of our investments.
- Regulatory liabilities increased \$25.2 million primarily due to the increase in the regulatory liability related to the unrealized gain on the North Anna nuclear decommissioning fund.
- Deferred energy changed \$26.7 million as a result of the over-collection of our energy costs in 2020 as compared to an under-collection in 2019. The deferred energy balance was an under-collection of \$3.5 million at December 31, 2019, and an over-collection of \$23.1 million at December 31, 2020.

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 2020, 2019, and 2018, our operating activities provided cash flows of \$197.7 million, \$18.0 million, and \$58.2 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. We did not have any borrowings outstanding under this facility as of December 31, 2020; however, the interest rate on borrowings would have been 1.1%. As of December 31, 2020, we had a \$0.5 million letter of credit outstanding under this facility. 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.

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 2018 through 2023:

	Actual			Projected		
	Year Ended December 31,			Year Ended December 31,		
	2018	2019	2020	2021	2022	2023
	(in millions)					
Wildcat Point	\$ 31.6	\$ 6.0	\$ 68.9	\$ 1.2	\$ 0.7	\$ 3.5
North Anna nuclear fuel	8.8	16.9	7.8	8.8	9.4	15.4
North Anna	7.1	2.6	15.6	9.8	10.6	18.4
Clover	11.4	7.4	1.3	1.8	2.5	4.9
Transmission	0.6	0.5	1.9	5.2	17.0	13.4
Combustion turbine facilities	1.1	2.3	2.7	3.3	0.2	0.2
Other	1.0	0.6	0.2	14.8	12.1	1.9
Total	<u>\$ 61.6</u>	<u>\$ 36.3</u>	<u>\$ 98.4</u>	<u>\$ 44.9</u>	<u>\$ 52.5</u>	<u>\$ 57.7</u>

Nearly all of our capital expenditures consist of additions to electric plant and equipment. Capital expenditures for North Anna include \$5.0 million, \$4.8 million, and \$14.1 million, for 2021, 2022, and 2023, respectively, for costs related to license extension. Capital expenditures for Transmission for 2021, 2022, and 2023 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, distributed generation facilities, and energy storage. Capital expenditures for Other in 2021 and 2022 include \$13.0 million and \$10.2 million, respectively, for costs related to energy storage. We intend to use our cash flow from operations, borrowings under our revolving credit facility, and, if needed, issuances of debt in the capital markets to fund all of our currently projected capital requirements through 2023.

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 energy and capacity, the financing of our operations, and other matters. See “Power Supply Resources—Power Purchase Contracts” in Item 1. The following table summarizes our long-term contractual obligations as of December 31, 2020:

	Payments due by Period				
	Total	2021	2022-2023	2024-2025	2026 and Thereafter
			(in millions)		
Long-term debt obligations	\$ 1,914.0	\$ 102.0	\$ 196.4	\$ 186.4	\$ 1,429.2
Power purchase obligations	90.7	52.2	38.3	0.2	—
Asset retirement obligations	179.1	—	—	—	179.1
Operating lease obligations	3.4	0.6	1.1	1.1	0.6
Total	<u>\$ 2,187.2</u>	<u>\$ 154.8</u>	<u>\$ 235.8</u>	<u>\$ 187.7</u>	<u>\$ 1,608.9</u>

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

Long-term Debt Obligations

As of December 31, 2020, 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 “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.

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, 2020, the collateral we had posted with counterparties pursuant to the power purchase and natural gas arrangements we have in place totaled \$7.5 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, 2020, if our credit ratings had been below investment grade we estimate we would have been obligated to post between \$75 million and \$125 million of collateral with our counterparties. This calculation is based on power and natural gas prices on December 31, 2020, 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, 2020, we had posted collateral totaling \$1.2 million. 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, 2020, 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 \$11.2 million.

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 "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, 2020, 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 "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, 2020, 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 \$700 million and \$750 million. Approximately 35% of the fair value of this portfolio is estimable using observable market prices. The remaining 65% 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 65% 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 \$25.0 million as of December 31, 2020. 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 “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.

Interest Rate Risk and Equity Price Risk

In 2020, all of our outstanding long-term debt accrued interest at fixed rates.

We maintain a revolving credit facility. See “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. We did not have any borrowings outstanding under this facility as of December 31, 2020; however, the interest rate on borrowings would have been 1.1%. As of December 31, 2020, we had a \$0.5 million letter of credit outstanding under this facility. 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, 2020.

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, 2020, \$166.3 million, \$74.2 million, and \$1.8 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 debt and 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 debt and equity markets will not have a material impact on our financial results.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED FINANCIAL STATEMENTS INDEX

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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, 2020, 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, 2020, 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 United States generally accepted accounting principles.

March 16, 2021

/s/ MARCUS M. HARRIS

Marcus M. Harris
President and Chief Executive Officer

/s/ BRYAN S. ROGERS

Bryan S. Rogers
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, 2020 and 2019, 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, 2020, 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, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, 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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for Asset Retirement and Environmental Obligations

*Description
of the
Matter*

At December 31, 2020 the Cooperative’s nuclear asset retirement obligation (“ARO”) at North Anna totaled \$156.9 million. As described in Note 3 to the consolidated financial statements, the Cooperative’s ARO associated with the legal obligation to retire North Anna Unit 1 and Unit 2 is recognized at fair value and capitalized as part of the related long-lived asset. The ARO is based on estimates and assumptions including the cost and method of decommissioning and the timing of the related cash flows, and the license period of the nuclear plant including the probability of license extensions. New decommissioning studies are performed approximately every four years or whenever factors indicate that there could be a material change to the estimate. The Cooperative, with the assistance of third-party experts, performed an updated decommissioning study in 2019. The Cooperative is not aware of any events that have occurred since the 2019 study that would materially impact the ARO estimate.

Auditing the Cooperative’s ARO was complex and highly judgmental due to the significant estimation required by management to determine the estimated present value of the legal obligation associated with the Cooperative’s nuclear facility at North Anna. For example, the estimate was sensitive to significant assumptions including the method of decommissioning and timing of related cash flows. Significant changes in management’s estimate could have a material effect on the Cooperative’s results of operations.

*How We
Addressed
the Matter
in Our Audit*

To test the ARO estimate, our audit procedures included testing the significant assumptions and inputs including the timing of activities, projected license periods, and the method of decommissioning. For example, we compared current year regulatory requirements and recent market data to the information used by the Cooperative. We involved a specialist to assist in our evaluation of the factors discussed above that could impact the Cooperative’s retirement obligation. We tested the completeness and accuracy of the underlying data.

/s/ Ernst & Young LLP

We have served as the Cooperative’s auditor since 2000.
Richmond, Virginia
March 16, 2021

OLD DOMINION ELECTRIC COOPERATIVE

**CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2020 AND 2019**

	2020	2019
ASSETS:	(in thousands)	
Electric Plant:		
Property, plant, and equipment	\$2,536,395	\$2,531,986
Less accumulated depreciation	(984,076)	(927,065)
Net Property, plant, and equipment	1,552,319	1,604,921
Nuclear fuel, at amortized cost	17,321	20,705
Construction work in progress	38,810	31,462
Net Electric Plant	<u>1,608,450</u>	<u>1,657,088</u>
Investments:		
Nuclear decommissioning trust	242,337	211,108
Unrestricted investments and other	2,311	5,380
Total Investments	<u>244,648</u>	<u>216,488</u>
Current Assets:		
Cash and cash equivalents	9,288	3,469
Restricted cash and cash equivalents	—	24,230
Accounts receivable	16,909	12,422
Accounts receivable—members	79,813	101,185
Fuel, materials, and supplies	61,273	62,083
Deferred energy	—	3,548
Prepayments and other	5,598	4,702
Total Current Assets	<u>172,881</u>	<u>211,639</u>
Deferred Charges and Other Assets:		
Regulatory assets	31,131	57,742
Other assets	10,534	26,287
Total Deferred Charges and Other Assets	<u>41,665</u>	<u>84,029</u>
Total Assets	<u>\$2,067,644</u>	<u>\$2,169,244</u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 453,470	\$ 441,311
Non-controlling interest	5,853	5,846
Total Patronage capital and Non-controlling interest	459,323	447,157
Long-term debt	1,069,324	1,117,867
Revolving credit facility	—	67,200
Total Long-term debt and Revolving credit facility	<u>1,069,324</u>	<u>1,185,067</u>
Total Capitalization	<u>1,528,647</u>	<u>1,632,224</u>
Current Liabilities:		
Long-term debt due within one year	49,041	40,792
Accounts payable	61,044	147,916
Accounts payable—members	70,546	26,804
Accrued expenses	6,292	5,850
Deferred energy	23,112	—
Total Current Liabilities	<u>210,035</u>	<u>221,362</u>
Deferred Credits and Other Liabilities:		
Asset retirement obligations	179,133	173,669
Regulatory liabilities	142,724	117,483
Other liabilities	7,105	24,506
Total Deferred Credits and Other Liabilities	<u>328,962</u>	<u>315,658</u>
Total Capitalization and Liabilities	<u>\$2,067,644</u>	<u>\$2,169,244</u>

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, 2020, 2019, AND 2018**

	<u>2020</u>	<u>2019</u>	<u>2018</u>
		(in thousands)	
Operating Revenues	\$ 807,704	\$ 932,682	\$ 932,568
Operating Expenses:			
Fuel	144,348	172,921	187,118
Purchased power	250,546	332,216	397,589
Transmission	128,427	159,995	135,567
Deferred energy	26,660	22,522	(22,400)
Operations and maintenance	61,518	74,647	64,705
Administrative and general	43,023	48,938	45,171
Depreciation and amortization	69,902	68,752	62,503
Amortization of regulatory asset/(liability), net	9,069	(35,056)	(15,853)
Accretion of asset retirement obligations	5,463	5,539	5,319
Taxes, other than income taxes	9,275	9,412	9,493
Total Operating Expenses	<u>748,231</u>	<u>859,886</u>	<u>869,212</u>
Operating Margin	59,473	72,796	63,356
Other income (expense), net	(105)	(162)	(3,465)
Investment income	13,106	7,188	8,512
Interest income on North Anna Unit 3 cost recovery	—	—	141
Interest charges, net	(60,306)	(62,773)	(55,222)
Income taxes	(2)	(25)	(11)
Net Margin including Non-controlling interest	12,166	17,024	13,311
Non-controlling interest	(7)	(70)	(32)
Net Margin attributable to ODEC	12,159	16,954	13,279
Patronage Capital - Beginning of Period	441,311	428,663	415,384
Patronage Capital - Retirement	—	(4,306)	—
Patronage Capital - End of Period	<u>\$ 453,470</u>	<u>\$ 441,311</u>	<u>\$ 428,663</u>

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, 2020, 2019, AND 2018**

	<u>2020</u>	<u>2019</u>	<u>2018</u>
	(in thousands)		
Operating Activities:			
Net Margin including Non-controlling interest	\$ 12,166	\$ 17,024	\$ 13,311
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	69,902	68,752	62,503
Other non-cash charges	17,121	16,951	18,425
Amortization of lease obligations	—	—	4,919
Interest on lease deposits	—	—	(1,791)
Change in current assets	16,799	(27,530)	(2,151)
Change in deferred energy	26,660	22,521	(22,400)
Change in current liabilities	23,284	(23,692)	(2,361)
Change in regulatory assets and liabilities	33,157	(58,590)	(9,822)
Change in deferred charges and other assets and deferred credits and other liabilities	(1,432)	2,575	(2,449)
Net Cash Provided by Operating Activities	<u>197,657</u>	<u>18,011</u>	<u>58,184</u>
Investing Activities:			
Purchases of held to maturity securities	—	(3,115)	(37,844)
Proceeds from sale of held to maturity securities	3,115	5,573	145,422
Purchases of available for sale securities	(24,800)	(53,828)	—
Proceeds from sale of available for sale securities	24,800	53,828	—
Increase in other investments	(12,561)	(5,636)	(7,188)
Electric plant additions	(98,395)	(36,263)	(61,631)
Proceeds from sale of asset	—	—	115,000
Net Cash (Used for) Provided by Investing Activities	<u>(107,841)</u>	<u>(39,441)</u>	<u>153,759</u>
Financing Activities:			
Debt issuance costs	(235)	(257)	(255)
Payment of obligation under long-term lease	—	—	(108,602)
Payments of long-term debt	(40,792)	(40,792)	(40,792)
Draws on revolving credit facility	355,225	274,000	372,950
Repayments on revolving credit facility	(422,425)	(206,800)	(416,350)
Net Cash (Used for) Provided by Financing Activities	<u>(108,227)</u>	<u>26,151</u>	<u>(193,049)</u>
Net Change in Cash and Cash Equivalents and Restricted Cash and Cash Equivalents	<u>(18,411)</u>	<u>4,721</u>	<u>18,894</u>
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - Beginning of Period	<u>27,699</u>	<u>22,978</u>	<u>4,084</u>
Cash and Cash Equivalents and Restricted Cash and Cash Equivalents - End of Period	<u>\$ 9,288</u>	<u>\$ 27,699</u>	<u>\$ 22,978</u>

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO 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, 2020 and December 31, 2019. 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. In recent years, we have had no sales to TEC and TEC has had no sales to third parties. Additionally, we have a separate contract under which we may purchase natural gas from TEC; however, we have not purchased natural gas from TEC in recent years. 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.

The impact that the COVID-19 pandemic will have on our consolidated results of operations, financial condition, and cash flows is uncertain. We continue to actively manage our business to respond to this health crisis and will continue to evaluate the nature and extent of any impact.

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		
	2020	2019	2018
Wildcat Point ⁽¹⁾	3.1%	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

⁽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 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. 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, 2022, 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, 2020 and 2019, we had an outstanding receivable of \$3.2 million and \$3.9 million, respectively.

Fuel, Materials, and Supplies

Fuel, materials, and supplies is primarily composed of fuel and spare parts for our generating assets, renewable energy credits, and emission allowances, 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 2020, 2019, and 2018, was \$0.5 million, \$0.5 million, and \$11.2 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, 2020, 2019, and 2018.

Operating Revenues

Our operating revenues are derived from sales of power and renewable energy credits 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 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 2020, 2019, and 2018, 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,		
	2020	2019	2018
	(in thousands)		
Member distribution cooperatives			
Sales to member distribution cooperatives, excluding renewable energy credit sales	\$ 770,781	\$ 898,445	\$ 865,393
Renewable energy credit sales to member distribution cooperatives	33	26	16
Total sales to member distribution cooperatives	\$ 770,814	\$ 898,471	\$ 865,409
Non-members			
Sales to non-members, excluding renewable energy credit sales	\$ 31,452	\$ 29,539	\$ 64,209
Renewable energy credit sales to non-members	5,438	4,672	2,950
Total sales to non-members	\$ 36,890	\$ 34,211	\$ 67,159
Total operating revenues	\$ 807,704	\$ 932,682	\$ 932,568

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 of directors. 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 recover all of our costs and expenses or determines a change in cost allocation methodology among our member distribution cooperatives is appropriate, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval. On June 26, 2020, we submitted an application to FERC to revise our formula rate for a change in cost allocation methodology of our remaining owned capacity service rate, to be effective January 1, 2021. On August 25, 2020, FERC issued an order accepting our filing with an effective date of January 1, 2021.

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,		
	2020	2019	2018
	(in thousands)		
Margin Stabilization adjustment	\$13,227	\$7,175	\$15,312

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 \$5.7 million and \$6.2 million as of December 31, 2020 and 2019, respectively, and are included as a direct reduction to long-term debt. Capitalized costs associated with our revolving credit facility totaled \$0.9 million and \$1.0 million as of December 31, 2020 and 2019, respectively, and are recorded in other assets. 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 revenues collected from our member distribution cooperatives and our energy expenses. 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, 2020 and 2019, we had an over-collected deferred energy balance of \$23.1 million and an under-collected deferred energy balance of \$3.5 million, respectively.

The following table summarizes the changes to our total energy rate since 2018, which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Rate Change	% Change
January 1, 2018	11.1
April 1, 2018	3.7
January 1, 2019	(1.3)
January 1, 2020	(16.2)
January 1, 2021	(15.9)

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 in other assets and other liabilities. 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 was paid on March 27, 2020.

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 \$79.8 million and \$101.2 million, as of December 31, 2020 and 2019, 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,	
	2020	2019
	(in thousands)	
Cash and cash equivalents	\$ 9,288	\$ 3,469
Restricted cash and cash equivalents	—	24,230
Total	\$ 9,288	\$ 27,699

Restricted cash and cash equivalents related to funds held in escrow for payments related to the construction of Wildcat Point and in July 2020 the funds were released and paid to the contractors.

New Accounting Pronouncements

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 adopted this standard for the fiscal year beginning January 1, 2020, and it did not have a material impact on our financial statements.

In March 2020, the FASB issued ASU 2020-04 Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The guidance provides temporary optional expedients and exceptions related to contract modifications and hedge accounting to ease entities' financial reporting burdens as the market transitions from the LIBOR and other interbank offered rates to alternative reference rates. The new guidance allows entities to elect not to apply certain modification accounting requirements, if certain criteria are met, to contracts affected by what the guidance calls reference rate reform. An entity that makes this election would consider changes in reference rates and other contract modifications related to reference rate reform to be events that do not require contract remeasurement at the modification date or reassessment of a previous accounting determination. The ASU notes that changes in contract terms that are made to effect the reference rate reform transition are considered related to the replacement of a reference rate if they are not the result of a business decision that is separate from or in addition to changes to the terms of a contract to effect that transition. The guidance is effective upon issuance and generally can be applied as of March 12, 2020 through December 31, 2022. We are continuing to evaluate the impact of this standard on our financial statements.

NOTE 2—Electric Plant

Our net electric plant was composed of the following as of December 31, 2020:

	Wildcat Point	North Anna	Clover	Combustion Turbine Facilities	Other	Total
	(in thousands)					
Property, plant, and equipment	\$875,528	\$ 415,227	\$ 706,417	\$ 438,418	\$100,805	\$2,536,395
Accumulated depreciation	(71,656)	(249,546)	(401,363)	(228,378)	(33,133)	(984,076)
Net Property, plant, and equipment	803,872	165,681	305,054	210,040	67,672	1,552,319
Nuclear fuel, at amortized cost	—	17,321	—	—	—	17,321
Construction work in progress	989	34,961	1,110	—	1,750	38,810
Net Electric Plant	<u>\$804,861</u>	<u>\$ 217,963</u>	<u>\$ 306,164</u>	<u>\$ 210,040</u>	<u>\$ 69,422</u>	<u>\$1,608,450</u>

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	<u>\$830,343</u>	<u>\$ 218,483</u>	<u>\$ 318,471</u>	<u>\$ 220,673</u>	<u>\$ 69,118</u>	<u>\$1,657,088</u>

Wildcat Point

We own Wildcat Point, a 977 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. 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, 2020 and 2019, we had an outstanding accounts payable balance of \$3.8 million and \$6.2 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, 2020 and 2019, we had an outstanding accounts payable balance of \$2.1 million and \$6.8 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, 2020 and 2019, our share of North Anna's nuclear decommissioning asset retirement obligation totaled \$156.9 million and \$152.4 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 or that would have required an updated study to be performed in 2020. We are required to maintain a funded trust to satisfy our future obligation to decommission the North Anna facility. See Note 9—Investments.

The following represents changes in our asset retirement obligations for the years ended December 31, 2020 and 2019 (in thousands):

Asset retirement obligations as of December 31, 2018	\$ 130,488
Accretion expense	5,539
Increase in asset retirement obligations - new layer	<u>37,642</u>
Asset retirement obligations as of December 31, 2019	\$ 173,669
Accretion expense	<u>5,464</u>
Asset retirement obligations as of December 31, 2020	<u><u>\$ 179,133</u></u>

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, submitted an application to the NRC in August 2020 for an additional 20-year operating license extension for North Anna. 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 2020, 2019, and 2018, our owned generating facilities together furnished approximately 52.0%, 56.3%, and 57.1%, 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. As of December 31, 2020 and 2019, we had posted \$7.5 million and \$24.7 million, respectively. Additionally, we may be required to post collateral with PJM to support our obligations in connection with our PJM transactions. As of December 31, 2020 and 2019, we had posted \$1.2 million and \$0.5 million, respectively.

Our purchased power expense for 2020, 2019, and 2018 was \$250.5 million, \$332.2 million, and \$397.6 million, respectively.

As of December 31, 2020, our power purchase obligations under the various agreements were as follows:

<u>Year Ended December 31,</u>	Capacity and Energy Obligations
	(in millions)
2021	\$ 52.2
2022	1.9
2023	36.4
	<u>\$ 90.5</u>

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 less than 3.0% of our member distribution cooperatives' total energy requirements in 2020.

There are two additional limited exceptions to the all-requirements nature of the contracts. One exception permits each of our member distribution cooperatives 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, 2020, none of our member distribution cooperatives had utilized this latter exception.

If all of our member distribution cooperatives elected to fully 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.

<u>As of December 31,</u>	MW
2018	107
2019	108
2020	111

Beginning January 1, 2021, the cumulative removal of load requirements under this exception is approximately 140 MW. 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.

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

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Rappahannock Electric Cooperative	\$ 237.6	\$ 279.7	\$ 266.9
Shenandoah Valley Electric Cooperative	144.5	168.4	164.7
Delaware Electric Cooperative, Inc.	110.0	121.6	115.5
Choptank Electric Cooperative, Inc.	73.7	83.1	81.2
Southside Electric Cooperative	56.9	69.8	67.7
A&N Electric Cooperative	48.0	54.7	53.7
Mecklenburg Electric Cooperative	36.8	45.1	44.0
Prince George Electric Cooperative	22.9	26.9	25.7
Northern Neck Electric Cooperative	20.2	24.1	22.2
Community Electric Cooperative	11.0	14.1	13.5
BARC Electric Cooperative	9.2	11.0	10.3
Total	<u>\$ 770.8</u>	<u>\$ 898.5</u>	<u>\$ 865.4</u>

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, 2020 and 2019:

	December 31, 2020	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⁾	\$ 76,037	\$ 76,037	\$ —	\$ —
Nuclear decommissioning trust - net asset value ⁽¹⁾⁽²⁾	166,300	—	—	—
Unrestricted investments and other ⁽³⁾	166	—	166	—
Derivatives - gas and power ⁽⁴⁾	3,478	1,582	480	1,416
Total Financial Assets	\$ 245,981	\$ 77,619	\$ 646	\$ 1,416
Derivatives - gas and power ⁽⁴⁾	\$ 6,406	\$ —	\$ 6,406	\$ —
Total Financial Liabilities	\$ 6,406	\$ —	\$ 6,406	\$ —

	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	\$ —

(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. Sensitivity in the market price of financial transmission rights could impact the fair value. For additional information about our derivative financial instruments, see Note 1—Summary of Significant Accounting Policies.

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:

Commodity	Unit of Measure	Quantity	
		As of December 31, 2020	As of December 31, 2019
Natural Gas	MMBTU	55,630,000	73,560,000
Purchased power - financial transmission rights	MWh	6,922,373	5,771,291

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

Balance Sheet Location	Fair Value		
	As of December 31, 2020	As of December 31, 2019	
(in thousands)			
Derivatives in an asset position:			
Natural gas futures contracts	Other assets	\$ 2,062	\$ —
Financial transmission rights	Other assets	1,416	1,013
Total derivatives in an asset position		<u>\$ 3,478</u>	<u>\$ 1,013</u>
Derivatives in a liability position:			
Natural gas futures contracts	Other liabilities	\$ 6,406	\$ 24,125
Total derivatives in a liability position		<u>\$ 6,406</u>	<u>\$ 24,125</u>

The Effect of Derivative Instruments on the Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Years Ended December 31, 2020 and 2019

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of December 31,		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,	
	2020	2019		2020	2019
(in thousands)					
Natural gas futures contracts	\$ (5,043)	\$ (25,996)	Fuel	\$ (37,242)	\$ (19,770)
Purchased power	1,416	1,013	Purchased Power	(261)	(4,579)
Total	<u>\$ (3,627)</u>	<u>\$ (24,983)</u>		<u>\$ (37,503)</u>	<u>\$ (24,349)</u>

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, 2020 and 2019:

Description	Cost	Gross	Gross	Fair	Carrying
		Unrealized	Unrealized		
		Gains	Losses	Value	Value
(in thousands)					
December 31, 2020					
Nuclear decommissioning trust ⁽¹⁾					
Debt securities	\$ 66,727	\$ 7,493	\$ —	\$ 74,220	\$ 74,220
Equity securities	89,472	76,828	—	166,300	166,300
Cash and other	1,817	—	—	1,817	1,817
Total Nuclear Decommissioning Trust	\$ 158,016	\$ 84,321	\$ —	\$ 242,337	\$ 242,337
Other					
Equity securities	\$ 132	\$ 34	\$ —	\$ 166	\$ 166
Non-marketable equity investments	2,145	2,340	—	4,485	2,145
Total Other	\$ 2,277	\$ 2,374	\$ —	\$ 4,651	\$ 2,311
					\$ 244,648
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

⁽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, 2020, were as follows:

Description	Less than	1-5 years	5-10 years	More than	Total
	1 year		(in thousands)	10 years	
Other ⁽¹⁾	\$ —	\$ —	\$ 74,220	\$ —	\$ 74,220
Total	\$ —	\$ —	\$ 74,220	\$ —	\$ 74,220

⁽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, 2020 and 2019, were as follows:

	December 31,	
	2020	2019
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	\$ 4,382	\$ 6,247
Deferred asset retirement costs	246	263
NOVEC contract termination fee	19,575	22,022
Interest rate hedge	1,754	1,907
Voluntary prepayment to NRECA Retirement Security Plan	1,547	2,320
Deferred net unrealized losses on derivative instruments	3,627	24,983
Total Regulatory Assets	<u>\$ 31,131</u>	<u>\$ 57,742</u>
Regulatory Assets included in Current Assets:		
Deferred energy	\$ —	\$ 3,548
Regulatory Liabilities:		
North Anna asset retirement obligation deferral	\$ 58,231	\$ 51,626
North Anna nuclear decommissioning trust unrealized gain	84,321	65,626
Unamortized gains on reacquired debt	172	231
Total Regulatory Liabilities	<u>\$ 142,724</u>	<u>\$ 117,483</u>
Regulatory Liabilities included in Current Liabilities		
Deferred energy	\$ 23,112	\$ —

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 revenues collected from our member distribution cooperatives and our energy expenses. 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.

Regulatory liabilities included in current liabilities are detailed as follows:

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

NOTE 11—Long-term Debt

Long-term debt consists of the following:

	December 31,	
	2020	2019
	(in thousands)	
\$250,000,000 principal amount of First Mortgage Bonds, 2017 Series A due 2037 at an interest rate of 3.33%	\$ 212,500	\$ 225,000
\$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%	60,000	63,000
\$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%	71,250	73,625
\$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	83,328	93,745
\$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	100,000	112,500
	<u>1,124,078</u>	<u>1,164,870</u>
Debt issuance costs	(5,713)	(6,211)
Current maturities	(49,041)	(40,792)
	<u>\$ 1,069,324</u>	<u>\$ 1,117,867</u>

As of December 31, 2020 and 2019, deferred gains and losses on reacquired debt totaled a net loss of approximately \$4.2 million and \$6.0 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)
2021	\$ 49,041
2022	49,041
2023	49,041
2024	49,041
2025	49,041
2026 and thereafter	878,873
	<u>\$ 1,124,078</u>

The aggregate fair value of long-term debt was \$1,374.8 million and \$1,300.1 million as of December 31, 2020 and 2019, 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. We did not have any borrowings outstanding under this facility as of December 31, 2020; however, the interest rate on borrowings would have been 1.1%. As of December 31, 2020, we had a \$0.5 million letter of credit outstanding under this facility. 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.

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, 2020 and 2019, were \$57.2 million and \$15.3 million, respectively. Amounts extended to our member distribution cooperatives are included in accounts receivable—members and as of December 31, 2020 and 2019, were \$6.5 million and \$20.5 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, 2020 and 2019, 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 2020.

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 \$4.0 million, \$3.7 million, and \$3.4 million in 2020, 2019, and 2018, 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 \$0.3 million in other liabilities.

Pension expense, inclusive of administrative fees, was \$5.1 million, \$4.7 million, and \$4.2 million for 2020, 2019, and 2018, respectively. Pension expense for 2020, 2019, and 2018 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 2020, 2019, and 2018.

NOTE 14—Supplemental Cash Flows Information

Cash paid for interest, net of amounts capitalized, in 2020, 2019, and 2018, was \$57.9 million, \$60.3 million, and \$52.9 million, respectively. Cash paid for income taxes was immaterial in 2020, 2019, and 2018. Accrued capital expenditures in 2020, 2019, and 2018 were \$3.8 million, \$69.8 million, and \$46.9 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 \$13.8 billion of liability protection on a per site, per nuclear incident basis, via obligations required of owners of nuclear power plants, and allows for an inflationary adjustment every five years. During the second quarter of 2020, the total liability protection per nuclear incident available to all participants in the secondary financial protection program decreased from \$13.9 billion to \$13.8 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 \$35.8 million as of December 31, 2020.

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.

Management's Annual Report on Internal Control over Financial Reporting

Our management has assessed our internal control over financial reporting as of December 31, 2020, 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, 2020, 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

There were no material changes that occurred during the last fiscal year that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We have not identified any adverse impact on our internal controls over financial reporting despite the majority of our headquarters personnel telecommuting due to the COVID-19 pandemic. The design of our processes and controls allows for remote execution with accessibility to secure data. We are continually monitoring and assessing the COVID-19 situation to minimize the impact, if any, on the design and operating effectiveness on our internal controls.

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 CEO 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, 2020, 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. (67). 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 (75). 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 2008.

John J. Burke, Jr. (64). 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 (74). 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. (77). 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 (69). 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 (57). 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.

Chad N. Fowler (42). 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. (75). 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 (59). 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.

Bruce A. Henry (75). 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.

John D. Hewa, Jr. (48). President and CEO of Rappahannock Electric Cooperative since August 2020. Mr. Hewa served as COO of Rappahannock Electric Cooperative from January 2020 to August 2020 and served as Vice President Corporate Services from July 2017 to December 2019. Mr. Hewa served as CEO of Pedernales Electric Cooperative, Inc. from July 2013 to May 2017. Mr. Hewa has been a director of ODEC since September 2020.

Bradley H. Hicks (50). President and CEO of Northern Neck Electric Cooperative since June 2020. Mr. Hicks served as President and CEO of Habersham EMC from October 2017 to September 2019. Mr. Hicks served as Vice President, Engineering and Energy Innovations at Pedernales Electric Cooperative, Inc. from January 2014 to June 2017. Mr. Hicks has been a director of ODEC since July 2020.

David J. Jones (72). 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 (44). 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. (60). 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. (41). 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. Mr. Logan has been a director of ODEC since April 2019.

Micheal E. Malandro (44). 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. Mr. Malandro has been a director of ODEC since 2015.

Suzanne S. Obenshain (58). Owner of SBVA Properties, LLC. since May 2005. Ms. Obenshain has been a director of ODEC since July 2020 and a director of Shenandoah Valley Electric Cooperative since June 2016.

Gregory S. Rogers (54). President and CEO of Shenandoah Valley Electric Cooperative since July 2020. Mr. Rogers served as Acting CEO of Shenandoah Valley Electric Cooperative from April 2020 to July 2020, as Vice President of Engineering and Operations from September 2016 to April 2020, and as Manager of District Operations from June 2010 to September 2016. Mr. Rogers has been a director of ODEC since May 2020.

Keith L. Swisher (66). 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.

Belvin Williamson, Jr. (57). 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, 2020, their respective ages, positions, and relevant business experience are listed below.

Marcus M. Harris (48). President and CEO of ODEC since April 2018. Mr. Harris served as Executive Vice President and CEO at Kansas Electric Power Cooperative from 2014 to March 2018.

Bryan S. Rogers (52). 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 2007 to June 2018.

D. Richard Beam (63). 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 2013 to December 2018.

Micheal L. Hern (65). 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 (51). Senior Vice President of Member Engagement since February 2019. Mr. Johnson served as Senior Vice President of Government Relations at NRECA from 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. Mr. Rogers and Mr. Beam were each awarded a bonus in 2020.

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 severance are set forth in his employment agreement. See "Employment Agreement" below. Other than our President and CEO, none of our 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 2020, employees could elect to have up to 100% or \$19,500, 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 2020 was \$6,500.

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 Deferred Compensation Plan as well as an annual contribution, if any, up to the maximum amount allowed by IRC regulations. 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 \$19,500 contribution to the plan for the benefit of our President and CEO in 2020. 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. 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 \$8,189 in 2020.

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 Compensation ⁽²⁾	Total
Marcus M. Harris President and CEO	2020	\$ 775,000	\$ —	\$ 191,296	\$ 33,389	\$ 999,685
	2019	675,000	—	83,835	25,872	784,707
	2018	472,875	—	32,701	62,683	568,259
Bryan S. Rogers Senior Vice President and CFO	2020	332,380	3,000	409,975	5,700	751,055
	2019	316,103	—	41,571	5,600	363,274
	2018	246,686	—	124,593	4,912	376,191
D. Richard Beam ⁽³⁾ Senior Vice President and COO	2020	347,526	3,000	419,008	5,700	775,234
	2019	337,404	—	55,076	5,600	398,080
	2018	317,764	—	464,383	5,500	787,647
Micheal L. Hern ⁽⁴⁾ General Counsel	2020	309,000	—	35,429	2,615	347,044
	2019	124,615	—	—	—	124,615
Kirk D. Johnson ⁽⁵⁾ Senior Vice President of Member Engagement	2020	339,900	—	352,259	5,700	697,859
	2019	279,231	—	86,147	27,139	392,517

(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, Mr. Rogers, 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 2020.

ALL OTHER COMPENSATION

Name	Matching Contributions under 401(k) Plan	Contributions under Deferred Compensation Plan	Perquisites and other personal benefits ⁽¹⁾	Total
Marcus M. Harris	\$ 5,700	\$ 19,500	\$ 8,189	\$ 33,389
Bryan S. Rogers	5,700	—	—	5,700
D. Richard Beam	5,700	—	—	5,700
Micheal L. Hern	2,615	—	—	2,615
Kirk D. Johnson	5,700	—	—	5,700

⁽¹⁾ For Mr. Harris, includes the personal use of a company automobile.

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 would 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 2020, ODEC made a contribution of \$19,500 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, 2020, 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:

Cash severance	\$ 775,000
Medical Insurance	22,302
Total	<u>\$ 797,302</u>

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, 2020, 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, 2020. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits was limited to \$285,000, effective January 1, 2020.

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	5.00	\$ 256,205	\$ —
	Executive Benefit Restoration Plan	2.67	139,222	—
Bryan S. Rogers	NRECA Retirement Security Plan	23.33	1,309,296	—
	Executive Benefit Restoration Plan	23.33	42,340	—
D. Richard Beam	NRECA Retirement Security Plan	33.33	2,880,612	—
	Deferred Compensation Pension Restoration Plan	33.33	—	93,135
Micheal L. Hern ⁽²⁾	NRECA Retirement Security Plan	0.42	35,429	—
Kirk D. Johnson ⁽³⁾	NRECA Retirement Security Plan	18.00	1,103,708	—
	Executive Benefit Restoration Plan	1.92	33,759	—

⁽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 2.67 years of credited service with ODEC.

⁽²⁾ Mr. Hern became eligible to participate in the NRECA Retirement Security Plan in July 2020, after he completed 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 1.92 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 (2.28% for 2020) and the PPA three segment yield rates (2.04%, 3.09%, and 3.68% for 2020) 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 2020 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. Because Mr. Beam has reached normal retirement, 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 \$19,500 for 2020, 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 2020:

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	\$ —	\$ 19,500	\$ 20,923	\$ —	\$ 166,219
Bryan S. Rogers	—	—	—	—	—
D. Richard Beam	—	—	—	—	—
Micheal L. Hern	—	—	—	—	—
Kirk D. Johnson	—	—	—	—	—

⁽¹⁾ For Mr. Harris, includes a \$19,500 ODEC contribution to the Deferred Compensation Plan, which is included 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 \$32,104, which was previously reported as compensation to Mr. Harris in our Summary Compensation Table for fiscal years prior to fiscal year 2020.

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 2020, 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 2020:

DIRECTOR COMPENSATION

Name	Fees Earned or Paid	
	in Cash	Total
Paul H. Brown	\$ 46,100	\$ 46,100
John J. Burke, Jr.	45,850	45,850
Darlene H. Carpenter	47,100	47,100
Earl C. Currin, Jr.	46,100	46,100
E. Garrison Drummond	45,600	45,600
Chad N. Fowler	45,600	45,600
Hunter R. Greenlaw, Jr.	46,350	46,350
Bruce A. Henry	46,100	46,100
David J. Jones	46,350	46,350
Robbie F. Marchant	27,100	27,100
Suzanne S. Obenshain	19,750	19,750
Keith L. Swisher	46,350	46,350
	<u>\$ 508,350</u>	<u>\$ 508,350</u>

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 exception 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. 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 CEO 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 \$999,685 in 2020. Based on reasonable estimates, the median annual total compensation of all of our employees, excluding our President and CEO, was \$205,153 for 2020. Accordingly, for 2020, 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 4.9 to 1.

We identified our median employee based on salary earned in 2020 by each individual who was employed by us on November 15, 2020. 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.

John C. Lee, Jr., Chair
E. Garrison Drummond
Jeffrey S. Edwards
Chad N. Fowler
Micheal E. Malandro
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.

	<u>2020</u>	<u>2019</u>
Audit Fees ⁽¹⁾	\$ 368,740	\$ 358,000
Audit-Related Fees ⁽²⁾	3,000	25,744
Tax Fees ⁽³⁾	8,704	10,506
All Other Fees	—	—
Total	<u>\$ 380,444</u>	<u>\$ 394,250</u>

- (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 2020 and 2019, 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 2020 and 2019, 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 43
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 \(filed as exhibit 10.19 to the Registrant's Form 10-K for the year ended December 31, 2019, File No. 000-50039, on March 11, 2020\).](#)

*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 \(filed as exhibit 10.21 to the Registrant' Form 10-K for the year ended December 31, 2019, File No. 000-50039, on March 11, 2020\).](#)

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 16, 2021

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

<u>/s/ STEVEN A. HARMON</u> Steven A. Harmon	Director
<u>/s/ BRUCE A. HENRY</u> Bruce A. Henry	Director
<u>/s/ JOHN D. HEWA, JR.</u> John D. Hewa, Jr.	Director
<u>/s/ BRADLEY H. HICKS</u> Bradley H. Hicks	Director
<u>/s/ DAVID J. JONES</u> David J. Jones	Director
<u>/s/ MICHAEL J. KEYSER</u> Michael J. Keyser	Director
<u>/s/ JOHN C. LEE, JR.</u> John C. Lee, Jr.	Director
<u>/s/ CARY J. LOGAN, JR.</u> Cary J. Logan, Jr.	Director
<u>/s/ MICHEAL E. MALANDRO</u> Micheal E. Malandro	Director
<u>/s/ SUZANNE S. OBENSHAIN</u> Suzanne S. Obenshain	Director
<u>/s/ GREGORY S. ROGERS</u> Gregory S. Rogers	Director
<u>/s/ KEITH L. SWISHER</u> Keith L. Swisher	Director
<u>/s/ BELVIN WILLIAMSON, JR.</u> 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 2020. Accordingly, ODEC will not file an annual report with the Securities and Exchange Commission.

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 16, 2021

/s/ MARCUS M. HARRIS

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

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 16, 2021

/s/ BRYAN S. ROGERS

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

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-K for the period ending December 31, 2020 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 16, 2021

/s/ MARCUS M. HARRIS

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

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-K for the period ending December 31, 2020 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 16, 2021

/s/ BRYAN S. ROGERS

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

**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, 2021

OR

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

For the transition period from _____ to _____
Commission file number 000-50039

OLD DOMINION ELECTRIC COOPERATIVE

(Exact name of Registrant as specified in its charter)

VIRGINIA
(State or other jurisdiction of
incorporation or organization)

4201 Dominion Boulevard, Glen Allen, Virginia
(Address of principal executive offices)

23-7048405
(I.R.S. employer
identification no.)

23060
(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	<input type="checkbox"/>	Accelerated filer	<input type="checkbox"/>
Non-accelerated filer	<input checked="" type="checkbox"/>	Smaller reporting company	<input type="checkbox"/>
Emerging growth company	<input type="checkbox"/>		

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

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

2021 ANNUAL REPORT ON FORM 10-K

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GLOSSARY OF TERMS

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

<u>Abbreviation or Acronym</u>	<u>Definition</u>
ACE	Affordable Clean Energy rule
ACES	Alliance for Cooperative Energy Services Power Marketing, LLC
ASU	Accounting Standards Update
CAA	Clean Air Act
CCR	Coal combustion residual(s)
CEC	Choptank Electric Cooperative, Inc.
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CLO	Chief Legal 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	United States Department of Energy
EPA	Environmental Protection Agency
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
MMBTU	One Million British Thermal Units
Moody's	Moody's Investors Service
MPSC	Maryland Public Service Commission
MW	Megawatt(s)
MWh	Megawatt hour(s)
NEO	Named executive officer(s)
NERC	North American Electric Reliability Corporation
North Anna	North Anna Nuclear Power Station
NOVEC	Northern Virginia Electric Cooperative
NO _x	Nitrogen oxide
NRC	United States Nuclear Regulatory Commission
NRECA	National Rural Electric Cooperative Association
NYMEX	New York Mercantile Exchange
ODEC, We, Our, Us	Old Dominion Electric Cooperative
PJM	PJM Interconnection, LLC
PPA	Pension Protection Act
REC	Rappahannock Electric Cooperative
RGGI	Regional Greenhouse Gas Initiative
RPM	Reliability Pricing Model
RPS	Renewable portfolio standards

Abbreviation or Acronym

RTO
RUS
S&P
SEPA
SO₂
SVEC
TEC
VAPCB
Virginia Power
VSCC
Wildcat Point
XBRL

Definition

Regional transmission organization
United States Department of Agriculture Rural Utilities Service
Standard & Poor's Financial Services LLC
Southeastern Power Administration
Sulfur dioxide
Shenandoah Valley Electric Cooperative
TEC Trading, Inc.
Virginia Air Pollution Control Board
Virginia Electric and Power Company
Virginia State Corporation Commission
Wildcat Point Generation Facility
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 wholesale 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 2021.

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, that are also either the cooperative's wholesale or retail customers. Cooperatives are organized 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).

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, expenses, or margins.

Revenues from our member distribution cooperatives and the percentage each contributed to total revenues from sales to our member distribution cooperatives in 2021 were as follows:

Member Distribution Cooperatives	Revenues	
	(in millions)	
Rappahannock Electric Cooperative	\$ 223.3	30.7%
Shenandoah Valley Electric Cooperative	138.2	19.0
Delaware Electric Cooperative, Inc.	109.1	15.0
Choptank Electric Cooperative, Inc.	72.1	9.9
Southside Electric Cooperative	51.8	7.1
A&N Electric Cooperative	44.0	6.1
Mecklenburg Electric Cooperative	32.6	4.5
Prince George Electric Cooperative	20.2	2.8
Northern Neck Electric Cooperative	16.9	2.3
Community Electric Cooperative	10.5	1.5
BARC Electric Cooperative	8.2	1.1
Total	\$ 726.9	100.0%

In 2021, 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 2021 totaled approximately 12,100,000 MWh. These sales were divided by customer class as follows:



From 2016 through 2021, our eleven member distribution cooperatives experienced a compound annual growth rate of 1.5% in the number of customers (meters) and energy sales measured in MWh was relatively flat.

Our eleven member distribution cooperatives' average number of customers per mile of energized line is approximately 10 customers per mile, ranging from approximately 6 to 15 customers per mile. The average service density for all electric distribution cooperatives in the United States is approximately 8 customers per mile.

Delaware and Maryland each currently grant all retail customers the right to choose their power supplier. Virginia currently grants some 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 our member distribution cooperative, and obligates our 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 less than 2% of our member distribution cooperatives' total energy requirements in 2021.

There are two additional limited exceptions to the all-requirements nature of the contract. 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 of demand and associated energy from owned generation or other suppliers. Such load can be returned to us with proper notice. The other exception permits a member distribution cooperative to purchase additional power from other suppliers in limited circumstances following approval by our board of directors. As of December 31, 2021, none of our member distribution cooperatives had utilized this latter exception.

If all of our member distribution cooperatives elected to fully 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
2019	108
2020	111
2021	140

We do not anticipate that the current or potential full utilization of this exception or the return of load by our member distribution cooperatives will have a material impact on our results of operations, financial condition, 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.

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.

Our Delaware and Maryland member distribution cooperatives are not regulated by their respective public service commissions, including with respect to wholesale power costs that are a pass-through to their customers.

We are not subject to any RPS; however, DEC has committed to comply with the Delaware RPS even though it is not required by law to do so, which it meets 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, 2022, no retail customer of DEC or CEC had 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, two customers of our member distribution cooperatives have elected to choose an alternate supplier under this provision, removing approximately 10 MW of power. Retail choice is also available to any Virginia customer whose noncoincident peak demand exceeds 90 MW. Additionally, all Virginia retail customers may 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, 2021, all of our 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 results of operations, financial condition, 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. In recent years, we have had no sales to TEC and TEC has had no sales to third parties. Additionally, we have a separate contract under which we may purchase natural gas from TEC; however, we have not purchased natural gas from TEC in recent years. TEC does not engage in speculative trading.

POWER SUPPLY RESOURCES

General

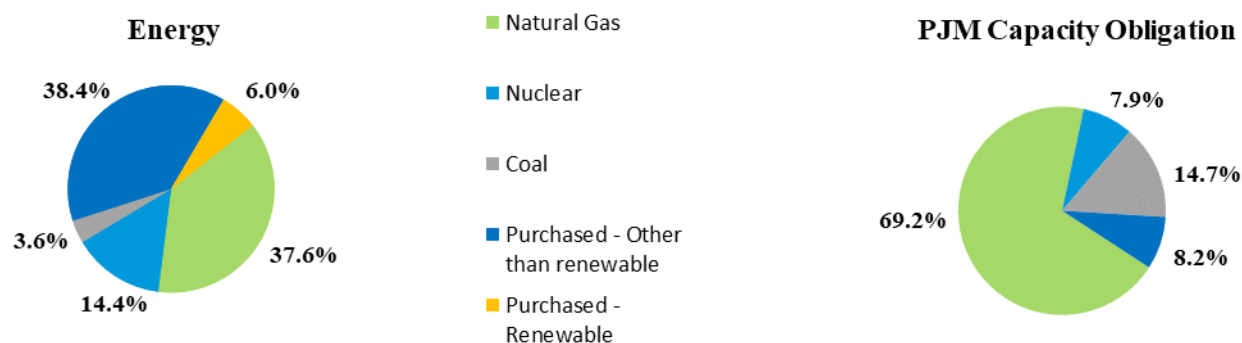
We provide power to our members through a combination of our interests in Wildcat Point, a natural gas-fired combined cycle generation facility; North Anna, a nuclear power station; Clover, a coal-fired generation facility; two natural gas-fired combustion turbine facilities (Louisa and Marsh Run); diesel-fired 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,					
	2021		2020		2019	
	(in MWh and percentages)					
Generated:						
Wildcat Point	3,477,212	28.1%	3,030,617	24.5%	3,400,633	27.2%
North Anna	1,783,076	14.4	1,832,792	14.8	1,777,573	14.2
Clover	446,329	3.6	620,324	5.0	640,119	5.1
Louisa	487,008	4.0	360,984	3.0	494,283	4.0
Marsh Run	681,180	5.5	582,648	4.7	716,390	5.8
Distributed Generation	3,011	—	2,536	—	2,327	—
Total Generated	6,877,816	55.6	6,429,901	52.0	7,031,325	56.3
Purchased:						
Other than renewable:						
Long-term and short-term	2,270,431	18.3	2,715,944	22.0	2,665,167	21.3
Spot market	2,483,820	20.1	2,438,563	19.7	2,047,654	16.4
Total Other than renewable	4,754,251	38.4	5,154,507	41.7	4,712,821	37.7
Renewable ⁽¹⁾	737,039	6.0	784,224	6.3	752,405	6.0
Total Purchased	5,491,290	44.4	5,938,731	48.0	5,465,226	43.7
Total Available Energy	12,369,106	100.0%	12,368,632	100.0%	12,496,551	100.0%

⁽¹⁾ Related to our contracts from renewable facilities from which we obtain renewable energy credits. We may sell these renewable energy credits to our member distribution cooperatives and non-members.

In 2021, our generating facilities satisfied approximately 91.8% of our weighted average PJM capacity obligation of approximately 2,733 MW. For a description of our generating facilities, see Item 2. In 2021, we satisfied 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.

Our total available energy and total PJM capacity obligation resources by fuel type and purchase type for 2021 are detailed below:



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 “Market Price Risk” in Item 7A.

Power Supply Planning and CO₂ Emission Goals

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. 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. We also evaluate other power supply options including the acquisition, development, or disposition of generating facilities.

As part of our ongoing power supply planning process, on February 3, 2021, we announced a goal to achieve net zero CO₂ emissions by 2050 and set an interim goal to reduce our carbon intensity (pounds of CO₂ emitted per MWh) by 50% (from 2005 levels) by 2030. As of December 31, 2021, we have reduced our carbon intensity by approximately 43% from 2005 levels. In addition to including carbon emissions related to our owned generating facilities, we impute carbon emissions for our market purchases using the PJM system average emission rate. We do not impute carbon emissions for any renewable power purchases for which we do not retire the renewable energy credits. We will continue to evaluate and monitor industry practices with respect to the calculation of carbon intensity and we may adjust our calculations accordingly.

PJM

PJM is an RTO that coordinates the transmission of wholesale electricity in all or parts of 13 states in the eastern United 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. 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 direction 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 “Transmission” in Item 2.

PJM balances its members’ 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 members 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 auctions of financial transmission rights for future periods to provide members 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 for generating facilities and hourly for load serving entities.

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 rules, known as RPM. PJM compensates us for the capacity of our generating facilities made available without regard to whether our generating facilities are dispatched. The purpose of PJM's capacity rules 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.

The PJM tariff includes a 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, are exposed to significant charges if their generation units do not perform during emergency conditions.

Power Purchase Contracts

We purchase significant amounts of power in the market 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 "Market Price Risk" in Item 7A.

Renewables

We have power purchase contracts for approximately 300 MW from wind, solar, and landfill gas facilities that are operational. We currently have approximately 50 MW of solar under contract that is projected to become operational between 2022 and 2025. Development of solar projects, including those for which we have currently contracted and may contract for in the future, are being impacted by delays and costs related to the regulatory approval and interconnection approval processes, and supply chain issues.

Our contracts for renewables allow us to buy output, including renewable energy credits, from the renewable facilities at predetermined prices. We may 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.

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 contracts to procure 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 "Risks Factors" in Item 1A and "Market Price 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 fuel 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, conditions, 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.

Coal

Virginia Power, as operating agent of Clover, has the sole authority and responsibility to procure coal for 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, 2021 and December 31, 2020, based on Clover running at full capacity, there was a 26-day and a 35-day supply of coal, respectively. The availability of coal is being impacted by the reduced production of coal, transportation issues, and exports of coal. See "Risk Factors" in Item 1A.

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 Virginia Department of Environmental Quality, 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, operation, or maintenance 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, or 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 "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 that could apply to our operations. 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 \$0.5 million and \$0.2 million in 2021 and 2020, 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 generating facilities limit emissions of SO₂, particulate matter, mercury, and NO_x. Additionally, regulatory programs are in place for new units and for major modifications of existing generating facilities, and are being proposed for existing units to limit emissions of CO₂ and other GHG. Discussed below are certain standards and regulations under the CAA that impact us.

- Cross-State Air Pollution Rule (“CSAPR”)
 - This rule requires power plants to reduce SO₂ 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 be able to purchase NO_x allowances and a limited number of SO₂ allowances to maintain compliance under the CSAPR program for Wildcat Point, Clover, Louisa, and Marsh Run.
- Acid Rain Program
 - This program requires fossil fuel-fired plants to have SO₂ allowances equal to the number of tons of SO₂ they emit into the atmosphere annually.
 - Clover receives an annual allocation of SO₂ allowances at no cost based on its baseline operations because it is a facility that was built before the Acid Rain Program commenced.
 - Wildcat Point, Louisa, and Marsh Run need to obtain allowances under the Acid Rain Program. Because they are primarily gas-fired generating facilities, the number of SO₂ allowances these facilities must obtain is typically minimal and can be supplied from any excess SO₂ allowances allocated to Clover.
- Greenhouse Gas Prevention of Significant Deterioration Permitting
 - These regulations set thresholds for GHG emissions that define when permits are required for new sources, as well as modifications to existing industrial facilities.
 - Future renewal of certain permits for Wildcat Point, Clover, Louisa, and Marsh Run may be affected.

Certain other environmental laws that affect our operations are discussed below.

Regional Greenhouse Gas Initiative (“RGGI”)

- RGGI, as implemented under the laws of participating northeastern and Mid-Atlantic States, including Virginia, Delaware, and Maryland, provides the framework for and administers a cap-and-trade program to regulate and reduce CO₂ emissions.
- Virginia joined RGGI in 2021 (see “Virginia Clean Economy Act” below). On January 15, 2022, the governor of the Commonwealth of Virginia issued an executive order directing the Virginia Department of Environmental Quality to explore options for Virginia’s withdrawal from RGGI, including repealing existing

regulations that enabled Virginia to join RGGI. We anticipate this process will take 12 to 18 months; however, the timing of the process is uncertain and may result in litigation.

- We are required to purchase RGGI CO₂ allowances for each ton of CO₂ emitted by Wildcat Point, Clover, Louisa, and Marsh Run.
- We continue to project that there will be an adequate supply of CO₂ allowances available for purchase through RGGI auctions or in the secondary market to support our generating facilities. RGGI is in the process of conducting a periodic program review. The results of this review could mean substantial changes to the emissions caps or other program market aspects. We are continuing to monitor this process, as well as the future inclusion of other adjoining states, to determine any potential impacts on allowance procurement.

Virginia Clean Economy Act

- In 2019, the VAPCB approved a regulation that reduces and limits CO₂ emissions from large (greater than 25 MW) electric power generating facilities.
- Virginia joined RGGI in 2021 and established the RGGI program with an effective starting date of January 1, 2021. (See “RGGI” above.)
- The act requires that the VAPCB establish rules by 2025 to reduce CO₂ emissions from the electric generating sector between 2031 and 2050 and specifies that no emission allowances will be issued in 2050 or future years.
- The act requires that substantially all investor-owned utility generating facilities that emit CO₂ as a by-product of combustion close by December 31, 2045, which would include Clover, which we co-own with Virginia Power, an investor-owned utility. However, if the reliability or security of providing electric service to customers is threatened, a petition may be made by Virginia Power to the VSCC requesting relief from the closure requirement.
- We will continue to be engaged in the development and implementation of the Virginia Clean Economy Act.

Clean Water Act

- This act regulates water intake structures, discharges of cooling water, storm water runoff, and other wastewater discharges at generating facilities.
- Our water permits are subject to periodic review and renewal proceedings.
- We do not currently expect a significant impact on our facility operations and will continue to follow revised rulemaking requirements to determine potential future impacts related to our facilities.

Resource Conservation and Recovery Act

- Rules under this act impose requirements relating to the disposal of CCRs generated by coal combustion at electric generating facilities.
- These requirements include establishing technical requirements for CCR landfills and surface impoundments, and for monitoring and cleanup of affected soil or groundwater.
- We do not currently expect the operations at Clover to be significantly affected and will continue to monitor the implementation of the CCR rules 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 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.

We anticipate that the most material new regulations are likely to arise under the CAA. Pending regulatory proceedings could result in modifications to certain National Ambient Air Quality Standards, the effect of which can ultimately include stricter emission requirements on new or existing facilities.

There also may be further developments relating to GHG emissions reporting, control, and facility permitting. The Clean Power Plan would have required states to implement specific plans to reduce CO₂ emissions. That regulation was revoked and was replaced with ACE, which was vacated and remanded on January 19, 2021, by the United States Court of Appeals for the District of Columbia Circuit. Continuing efforts to further reduce GHG emissions may lead to some form of replacement of ACE, which could result in limitations on the operations of our generating facilities and/or adversely affect our results of operations, financial condition, or cash flows.

We cannot predict the outcome of these or similar events relating to the regulation of our business, any of which could result in a material adverse impact on our results of operations, financial condition, or cash flows. See “Risk Factors” in Item 1A below.

Human Capital

Our success depends upon the skills and collective strengths of all of our employees. We focus on the health, safety, and well-being of our employees. We attract and retain our employees by offering competitive compensation and benefits packages, including healthcare, retirement, paid time off, and other benefits. Our workforce is composed of operational staff at our generating facilities and headquarters staff. We are not a party to any collective bargaining agreement. As of March 1, 2022, we had 134 employees, including 48 employees at our generating facilities and 86 employees at our headquarters office. The average tenure of our employees is 11 years.

ITEM 1A. 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 Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, including “Caution Regarding Forward-looking Statements,” and “Notes to Consolidated Financial Statements” in Item 8.

FINANCIAL, MARKET, AND ECONOMIC RISKS

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 2021, 64.7% 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. See “Members—Member Distribution Cooperatives—Wholesale Power Contracts” in Item 1 and “Factors Affecting Results—Formula Rate” in Item 7. 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.

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. When changes are necessary, we apply to FERC to modify our formula rate. As a result, one or more of our member distribution cooperatives, or its customers, could challenge the proposed modifications. Such a challenge likely would not cause us to fail to recover all of our costs and other amounts to be collected under the wholesale power contracts, but it could interfere with our ability to work as effectively as an organization as otherwise would be the case if disagreements with or among our member distribution cooperatives did not exist.

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 and delivery of power and fuel 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.

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 Item 7A.

We are subject to changes in fuel costs and delivery constraints 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, dispatch, 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 or firing of natural gas and coal; and
- war, acts and threats of terrorism, sabotage, natural disasters, pandemics, and other catastrophic events.

In 2021, we purchased approximately 44.4% 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. Purchases of energy from other suppliers will continue in the future and could 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.

Counterparties under energy 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. We cannot be assured that the defaulting counterparty will compensate us for any damages resulting from the breach of their obligations.

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 and natural gas 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+," "A1," 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. 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 future investors and funding sources could decrease.

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 would 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.

REGULATORY, LEGISLATIVE, AND ACCOUNTING RISKS

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

PJM, an RTO regulated by FERC, 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 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 direction 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. See “Power Supply Resources—PJM” in Item 1.

Environmental legislation or 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.

ACE, a replacement rule for the Clean Power Plan, regulating carbon emissions relating to existing sources such as generating facilities, was vacated on January 19, 2021, by the United States Court of Appeals for the District of Columbia Circuit. We are closely monitoring the EPA rulemaking related to ACE, and we currently cannot predict the potential impact on our existing generating facilities due to the uncertainties and complexities of the terms and effective date of the regulations.

In addition to new legislation or regulation, governmental administration priorities can change over time in ways that we cannot predict. Virginia joined RGGI in 2021 pursuant to the 2019 regulation that established an emission limitation program to reduce CO₂ from electric power facilities. Currently, Virginia is exploring potentially withdrawing from RGGI. See “Regulation—Environmental—Virginia Clean Economy Act” in Item 1.

We cannot predict the cost, effect, or duration 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. Also, the uncertainty related to changes in environmental laws and regulation poses risks related to long-term planning for generation assets and related decisions about future capital expenditures. See “Regulation—Environmental” in Item 1.

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

As a result of the Energy Policy Act of 2005, as amended, 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.

OPERATIONAL RISKS

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 14.4% of our energy requirements in 2021. 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 or transmission facilities.

The operation of our generating or transmission facilities involves risks, including the breakdown or failure of power generation equipment, transmission lines, piping or other equipment or processes, fuel supply availability and delivery constraints, 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;
- the purchase of potentially more costly replacement power on the open market; or
- substantial price risk due to availability and delivery of fuel constraints.

We are subject to coal procurement and delivery risks.

The operation of our coal generating facility involves risks, including the procurement and delivery of an adequate supply of coal to operate the facility and to meet the requirements of PJM. The availability of coal is being impacted by the reduced production of coal due to the closure of mines on the East Coast, transportation issues, and exports of coal to other countries which further reduces the available supply for domestic consumption.

TECHNOLOGY, CYBERSECURITY RISKS, AND OTHER THREATS

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. Deliberate or unintentional cybersecurity incidents, including ransomware, could directly or indirectly compromise our information related to the operation or maintenance of our generating or transmission facilities and could adversely affect our ability to operate or manage our generating or transmission facilities effectively or the ability of Virginia Power, as operator of North Anna and Clover, to do the same.

We also use third-party vendors to electronically process some of our business transactions. Information systems, both ours and those of third-party information processors, are vulnerable to cybersecurity breach. 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. We cannot be certain that the security measures utilized, including those security measures by third-party vendors, will be adequate against cyber threats and cyber attackers. In addition, cyber 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 or transmission 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 energy to our member distribution cooperatives. A major cyber incident for us or third-party vendors we utilize, 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.

Technological advancements and other changes impacting power requirements of our member distribution cooperatives' customers may alter energy and demand requirements 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.

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 United States 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.

COVID-19 PANDEMIC RISK

Our business and operations, and the operations of our member distribution cooperatives and suppliers, have been and will be impacted by the COVID-19 pandemic and could be similarly impacted by like events in the future.

The outbreak of COVID-19, declared by the World Health Organization to be a pandemic, spread across the world, including the United States. Because the severity, magnitude, and duration of the COVID-19 pandemic and its economic consequences are uncertain, rapidly changing, and difficult to predict, the ultimate impact on our operations and financial performance cannot be determined at this time. We expect that the longer the period of economic and global supply chain disruptions continue, the greater the risk that there could be a material adverse impact on our operations, results of operations, financial condition, or cash flows.

ODEC is considered an essential service provider and due to this pandemic we previously adjusted and may in the future need to adjust the schedules of our workforce at our owned generating facilities that we operate, specifically Wildcat Point, Louisa, and Marsh Run, and have a contingency plan for staffing at these facilities. We have ownership interests in North Anna and Clover that are operated by Virginia Power, which has taken similar measures. We have developed and implemented procedures to protect our employees from potential exposure to COVID-19 at our generating and corporate facilities. There can be no assurance that any of these measures will fully protect us from the impact of the ongoing COVID-19 pandemic. Beginning in mid-March 2020, the majority of our headquarters personnel began telecommuting with no disruption in business operations. While such practices have not impacted productivity or disrupted our business to date, over a prolonged period of time, such practices could adversely impact our ability to conduct our business in the ordinary course. Further, current and future potential employees may consider workplace practices and conditions, including the ability to telecommute, and this may impact our ability to retain and attract employees.

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	980 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					2,672 MW

⁽¹⁾ Net capacity entitlement represents (a) the projected maximum dependable capacity in summer conditions for Wildcat Point, (b) an approximation of our entitlement to the maximum dependable capacity in summer conditions for North Anna and Clover, and (c) 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.

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, submitted an application to the NRC in August 2020 for a 20-year operating license extension for North Anna.

Virginia Power is responsible for operating and procuring nuclear fuel for North Anna. See “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 “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.

The Virginia Clean Economy Act requires that substantially all investor-owned utility generating facilities that emit CO₂ as a by-product of combustion close by December 31, 2045, which would include Clover, which we co-own with Virginia Power, an investor-owned utility. However, if the reliability or security of providing electric service to customers is threatened, a petition may be made by Virginia Power to the VSCC requesting relief from the closure requirement.

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 on the Virginia mainland and the Virginia portion of the Delmarva Peninsula, 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 operational control of these transmission facilities to PJM and contracted with third parties to monitor 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 the first quarter of 2014, we incurred approximately \$14.9 million of costs related to the dispatch of our combustion turbine facilities for which we were directed by PJM to incur and were subsequently denied reimbursement. Our pursuit of recovery of these costs from PJM before FERC was unsuccessful.

We pursued recovery as a separate breach of an oral contract claim in the Circuit Court for the County of Henrico in the Commonwealth of Virginia. In 2019, PJM removed the matter to United States District Court for the Eastern District of Virginia and filed a motion to dismiss, and we filed a motion to remand the matter to state court. In 2020, the court granted PJM's motion to dismiss and denied our motion to remand the matter to state court. We filed a notice of appeal to the United States Court of Appeals for the Fourth Circuit, oral arguments were held on October 28, 2021, and on January 19, 2022, the court affirmed the denial of our motion to remand the matter back to state court and dismissed the case. We are currently evaluating our options. We did not record a receivable related to this matter.

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. [RESERVED]

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; the impact of the ongoing COVID-19 pandemic on our business, financial condition, and future operations; changes in and compliance with environmental laws and regulations; general credit and capital market conditions; weather conditions; the cost and availability of commodities used in our industry; disruption due to cybersecurity threats or incidents; 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 from operations for the year ended December 31, 2021, were primarily impacted by the decrease in our total energy rate to our member distribution cooperatives, the increase in the average cost of fuel, PJM's economic dispatch of our generating facilities, the increase in emissions allowances due to Virginia joining RGGI, and differences in weather.

- Total revenues from sales to our member distribution cooperatives decreased 5.7% as compared to 2020, primarily due to the 15.9% decrease in our total energy rate to our member distribution cooperatives effective January 1, 2021. The decrease was partially offset by the 3.8% increase in energy sales in MWh to our member distribution cooperatives. The weather in the first half of 2020 was mild and the weather in the first half of 2021 was more typical and contributed to the increase in energy sales in MWh.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased 6.4%. Purchased capacity costs decreased 38.1% due to the decrease in costs to meet our PJM capacity obligation. Purchased energy costs decreased 3.0% due to the 7.5% decrease in the volume of purchased energy, slightly offset by the 4.9% increase in the average cost of purchased energy. The decrease in the volume of purchased energy was primarily the result of increased generation from our owned facilities, due to PJM's economic dispatch.
- Fuel expense increased 15.4% as a result of the 7.8% increase in the average cost of fuel and the 7.0% increase in generation from our owned facilities.
- Operations and maintenance expense increased 27.3% primarily due to the increase in costs related to emissions allowances and scheduled outages at our owned facilities.
- Net margin attributable to ODEC increased \$7.9 million, as a result of the \$8.7 million equity contribution approved by our board of directors in December 2021. Subsequently our board of directors declared a patronage capital retirement of \$8.7 million.

Our financial condition as of December 31, 2021, was primarily impacted by the increase in the fair value of derivatives related to natural gas which contributed to increases in cash and cash equivalents, other assets, regulatory liabilities, and other liabilities.

We believe our results for 2021 were not materially impacted by the ongoing COVID-19 pandemic. We believe that other factors described above were the primary drivers of our results for 2021. We continue to closely monitor how the pandemic will affect our operations, results of operations, financial condition, and cash flows, and have taken certain actions as a result of the pandemic. See “Factors Affecting Results—COVID-19 Pandemic” below for a more detailed discussion.

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 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 revenues collected from our member distribution cooperatives and our energy expenses. 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 of directors, 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,		
	2021	2020	2019
	(in thousands)		
Margin Stabilization adjustment	\$11,614	\$13,227	\$7,175

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, 2021 and 2020, our share of North Anna’s nuclear decommissioning asset retirement obligation totaled \$161.5 million, or 87.4% of our total asset retirement obligations, and \$156.9 million, or 87.6% 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. We are not aware of any events that have occurred since the 2019 study that would materially impact our estimate or that would have required an updated study to be performed in 2021. See “Note 3—Accounting for Asset Retirement and Environmental Obligations” 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, 2021, for our asset retirement obligations related to nuclear decommissioning would have been \$44.0 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 other assets and other liabilities. 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.

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 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 of directors. 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 recover all of our costs and expenses or determines a change in cost allocation methodology among our member distribution cooperatives is appropriate, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval. On June 26, 2020, we submitted an application to FERC to revise our formula rate for a change in cost allocation methodology of our remaining owned capacity service rate, to be effective January 1, 2021. On August 25, 2020, FERC issued an order accepting our filing with an effective date of January 1, 2021.

Indenture

In addition to the requirements of our formula rate, 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. Margins for interest was 1.37, 1.21, and 1.29, for the years ended December 31, 2021, 2020, and 2019, respectively.

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.

COVID-19 Pandemic

Impact on Results of Operations and Financial Condition

For 2021, we do not believe there was a material impact attributable to the COVID-19 pandemic on our results of operations, financial condition, or cash flows.

In 2021, our total revenues decreased \$27.1 million, or 3.4%, as compared to 2020. The decrease was primarily due to the 15.9% decrease in our total energy rate to our member distribution cooperatives, effective January 1, 2021, partially offset by more typical weather in the first half of 2021 as compared to the mild weather in the first half of 2020.

Our operating revenues are derived from sales of power and renewable energy credits to our member distribution cooperatives 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 sell excess power and renewable energy credits to non-members at prevailing market prices as control is transferred. In 2021, energy sales in MWh to our member distribution cooperatives increased 3.8% as compared to the prior year. We believe a significant portion of the increase relates to differences in weather.

Any decline in our member distribution cooperatives' power requirements related to the COVID-19 pandemic would result in a reduction of our spot market energy purchases, or excess energy which we would sell to PJM, TEC, or third parties. In addition, the majority of our member distribution cooperatives' loads are residential, which may be a factor in limiting the impact of the pandemic on our results of operations.

The formula rate provides for the recovery of costs, margin requirement, and any additional equity contributions approved by our board of directors, from our member distribution cooperatives. See "Formula Rate" above. We operate on a cost plus specified margin basis; therefore, our net margin is not a function of total revenues. Our margin requirement is equal to 20% of actual interest charges, plus additional equity contributions approved by our board of directors. 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. To date, our member distribution cooperatives' ability to pay their invoices to us has not been impacted. Under an existing program, our member distribution cooperatives have the option to prepay their invoices from us or to extend payment of their invoices for 60 days. As of December 31, 2021, prepayments totaled \$92.3 million and there were no extended payments.

Workforce Considerations

We have transitioned back to pre-pandemic schedules at our generating facilities and have an ongoing contingency plan for staffing at these facilities. We have developed and implemented procedures to protect our employees from potential exposure to COVID-19 at our generating and corporate facilities. We believe we can maintain an adequate workforce at our generating facilities and corporate office to ensure no disruption in business operations.

Ongoing Considerations

We are continuing to monitor ways in which the impact of the ongoing COVID-19 pandemic could affect our operations, results of operations, financial condition, and cash flows. The extent to which the pandemic will impact us is uncertain and will depend on numerous evolving factors that we may not be able to accurately predict, including the duration and scope of the pandemic and the actions taken in response to the pandemic. See “Risk Factors” in Item 1A.

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. Through December 31, 2020, the remaining owned capacity service rate was billed to each of our member distribution cooperatives based on its contribution to the monthly zonal coincident peak. Beginning January 1, 2021, the remaining owned capacity service rate is billed based on the average hourly demand in the prior 12-month period from September 1 to August 31.

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:

	2021	2020	2019
Heating degree days	3,042	2,750	3,228
Cooling degree days	1,348	1,361	1,554

- *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 2021, our generating facilities satisfied approximately 91.8% of our PJM capacity obligation and 55.6% 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 "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 direction of PJM.

PJM balances its members' 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 "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 "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 either the peak hour of the year or the peak hour of each month, depending upon the transmission zone. 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 of demand and associated energy from owned generation or other suppliers. Such load can be returned to us with proper notice. 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 the current or potential full utilization of this exception or the return of load by our member distribution cooperatives will have a material impact on our operations, results of operations, financial condition, or cash flows. For further discussion on Wholesale Power Contracts, see "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 direction 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,		
	2021	2020	2019
Wildcat Point	88.2%	90.0%	75.6%
North Anna	91.5	93.6	91.3
Clover	74.9	69.8	68.9
Louisa	93.6	95.7	94.5
Marsh Run	96.6	92.1	94.2

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,		
	2021	2020	2019
Wildcat Point	40.4%	35.1%	40.7%
North Anna	92.8	95.1	92.5
Clover	12.0	16.6	17.1

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 2021 and 2020, one unit at North Anna was off-line for refueling and during 2019, both units at North Anna were off-line for refueling.

Changing Environmental Legislation and 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. The impact of these developments can have a material adverse effect on our results of operations, financial condition, or cash flows, depending on the final terms of new regulations and how those rules are implemented. See “Regulation—Environmental” in Item 1 and “Risk Factors” in Item 1A.

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,		
	2021	2020	2019
	(in thousands)		
Revenues from sales to:			
Member distribution cooperatives			
Energy revenues	\$ 328,045	\$ 375,714	\$ 471,767
Renewable energy credits	36	33	26
Demand revenues	398,819	395,067	426,678
Total revenues from sales to member distribution cooperatives	<u>726,900</u>	<u>770,814</u>	<u>898,471</u>
Non-members			
Energy revenues	45,255	31,431	29,483
Renewable energy credits	8,485	5,438	4,672
Demand revenues	—	21	56
Total revenues from sales to non-members	<u>53,740</u>	<u>36,890</u>	<u>34,211</u>
Total operating revenues	<u>\$ 780,640</u>	<u>\$ 807,704</u>	<u>\$ 932,682</u>
Energy sales to:			
	(in MWh)		
Member distribution cooperatives	11,329,811	10,916,844	11,483,669
Non-members	958,309	1,386,307	946,311
Total energy sales	<u>12,288,120</u>	<u>12,303,151</u>	<u>12,429,980</u>
Average cost of energy to member distribution cooperatives (per MWh)	\$ 28.95	\$ 34.42	\$ 41.08
Average total cost to member distribution cooperatives (per MWh)	\$ 64.16	\$ 70.61	\$ 78.24

Member Distribution Cooperatives

In 2021, total revenues from sales to our member distribution cooperatives decreased \$43.9 million, or 5.7%, as compared to 2020. Energy revenues decreased \$47.7 million, or 12.7%, primarily due to the 15.9% decrease in our total energy rate, effective January 1, 2021, partially offset by the 3.8% increase in energy sales in MWh to our member distribution cooperatives. The weather in the first half of 2020 was mild and the weather in the first half of 2021 was more typical and contributed to the increase in energy sales in MWh to our member distribution cooperatives. Demand revenues were relatively flat as compared to 2020.

The following table summarizes the changes to our total energy rate since 2019, which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Total Energy Rate Change	% Change
January 1, 2019	(1.3)
January 1, 2020	(16.2)
January 1, 2021	(15.9)
January 1, 2022	20.3

Operating Expenses

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

	Year Ended December 31,		
	2021	2020	2019
	(in thousands)		
Fuel	\$ 166,517	\$ 144,348	\$ 172,921
Purchased power	234,471	250,546	332,216
Transmission	131,290	128,427	159,995
Deferred energy	(28,116)	26,660	22,522
Operations and maintenance	78,294	61,518	74,647
Administrative and general	41,372	43,023	48,938
Depreciation and amortization	70,416	69,902	68,752
Amortization of regulatory asset/(liability), net	16,458	9,069	(35,056)
Accretion of asset retirement obligations	5,664	5,463	5,539
Taxes, other than income taxes	9,171	9,275	9,412
Total Operating Expenses	\$ 725,537	\$ 748,231	\$ 859,886

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 \$22.7 million, or 3.0%, for 2021 as compared to 2020, primarily as a result of the decreases in deferred energy expense and purchased power expense, partially offset by increases in fuel expense and operations and maintenance expense.

- Deferred energy expense, which represents the difference between energy revenues and energy expenses, decreased \$54.8 million. We under-collected \$28.1 million in 2021 and over-collected \$26.7 million in 2020.
- Purchased power expense, which includes the cost of purchased energy and capacity, decreased \$16.1 million, or 6.4%, due to the \$9.3 million, or 38.1%, decrease in capacity-related purchased power expense, and the \$6.8 million, or 3.0%, decrease in purchased energy costs. Purchased capacity costs decreased due to the decrease in costs to meet our PJM capacity obligation. Purchased energy costs decreased due to the 7.5% decrease in the volume of purchased energy, slightly offset by the 4.9% increase in the average cost of purchased energy. The decrease in the volume of purchased energy was the result of increased generation from our owned facilities, due to PJM’s economic dispatch.
- Fuel expense increased \$22.2 million, or 15.4%, as a result of the 7.8% increase in the average cost of fuel and the 7.0% increase in generation from our owned facilities.
- Operations and maintenance expense increased \$16.8 million, or 27.3%, primarily due to the increase in costs related to emissions allowances and scheduled outages at our owned facilities. The increase in emissions allowances was primarily due to our additional purchases of allowances to comply with state law following Virginia joining RGGI in 2021.

Other Items

Interest Charges, Net

The primary factors affecting our interest charges, net are issuances 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,		
	2021	2020	2019
	(in thousands)		
Interest on long-term debt	\$ (55,705)	\$ (57,831)	\$ (59,931)
Interest on revolving credit facility	(400)	(2,078)	(802)
Other interest	(429)	(888)	(2,506)
Total interest charges	(56,534)	(60,797)	(63,239)
Allowance for borrowed funds used during construction	877	491	466
Interest charges, net	<u>\$ (55,657)</u>	<u>\$ (60,306)</u>	<u>\$ (62,773)</u>

Net Margin Attributable to ODEC

In 2021, 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 \$7.9 million, as a result of the \$8.7 million equity contribution in 2021 and the absence of an equity contribution in 2020. See “Factors Affecting Results—Formula Rate” above and “Note 1—Summary of Significant Accounting Policies—Patronage Capital” in Item 8.

Patronage Capital Retirement

On December 14, 2021, our board of directors approved an additional equity contribution of \$8.7 million, and subsequently declared a patronage capital retirement of \$8.7 million. As a result of the December 14, 2021 declaration, we reduced patronage capital and increased accounts payable—members by \$8.7 million. The \$8.7 million patronage capital retirement will be paid on March 25, 2022.

Discussion of Results of Operations Comparing 2020 to 2019

For discussion of our financial results comparing 2020 to 2019, see “Results of Operations” in Item 7 of our 2020 Annual Report on Form 10-K, filed with the Securities and Exchange Commission on March 16, 2021.

Financial Condition

The principal changes in our financial condition from December 31, 2020 to December 31, 2021, were caused by increases in regulatory liabilities, other assets, accounts payable—members, nuclear decommissioning trust, accounts payable, and other liabilities; the decrease in accounts receivable—members; and the change in deferred energy.

- Regulatory liabilities increased \$77.9 million primarily due to the increase in the fair value of derivatives related to natural gas and financial transmission rights, and the unrealized gain on the North Anna nuclear decommissioning fund.
- Other assets increased \$44.9 million primarily due to the increase in the fair value of derivatives related to natural gas and financial transmission rights.
- Accounts payable—members increased \$42.2 million primarily due to the \$35.1 million increase in member prepayments and the \$8.7 million patronage capital retirement in 2021.
- Nuclear decommissioning trust increased \$34.3 million due to the increase in the market value of the investments.
- Accounts payable increased \$21.9 million due to the increase in trade payables.

- Other liabilities increased \$20.3 million primarily due to the decrease in the NYMEX margin account for derivatives related to natural gas.
- Accounts receivable—members decreased \$16.8 million due to the \$10.3 million decrease in wholesale power invoices for December 2021 as compared to December 2020, and the \$6.5 million decrease in member distribution cooperatives' extended payment balances.
- Deferred energy changed \$28.1 million as a result of the under-collection of our energy costs in 2021 as compared to an over-collection in 2020. The deferred energy balance was an under-collection of \$5.0 million at December 31, 2021, and an over-collection of \$23.1 million at December 31, 2020.

Equity Ratio

Our equity ratio was 30.3% and 28.8%, as of December 31, 2021 and 2020, respectively. 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.

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 2021, 2020, and 2019, our operating activities provided cash flows of \$197.6 million, \$197.7 million, and \$18.0 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 totaled \$500 million through March 3, 2022, and \$400 million from March 4, 2022 through February 28, 2025. We did not have any borrowings outstanding under this facility as of December 31, 2021 and 2020; however, the interest rate on borrowings would have been 1.1%. As of December 31, 2021 and 2020, we had a \$0.5 million letter of credit outstanding under this facility.

The syndicated credit agreement contains customary conditions to borrowing and the issuance of letters of credit, representations and warranties, covenants, and 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. These events of default include:

- 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 and a margins for interest 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 and the substitution of a new benchmark replacement 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. We currently have no plans to construct a major new generating facility or issue any additional long-term indebtedness in the near term. We believe our cash from operations and funds available from our revolving credit facility will be sufficient to meet our currently anticipated future operational and capital requirements.

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. Additionally, we have asset retirement obligations in the future that are significantly offset by the nuclear decommissioning trust, which as of December 31, 2021, had a balance of \$276.7 million. Our future contingent obligations primarily relate to power purchase and natural gas arrangements and we have no off-balance sheet obligations. 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. We currently anticipate that cash from operations and borrowings under our revolving credit facility will be sufficient to meet our liquidity needs for the near term, including planned capital expenditures, decommissioning trust obligations, and our contingent obligations as described above.

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, projects currently under consideration, 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 2019 through 2024:

	Actual			Projected		
	Year Ended December 31,			Year Ended December 31,		
	2019	2020	2021	2022	2023	2024
	(in millions)					
Wildcat Point	\$ 6.0	\$ 68.9	\$ 1.7	\$ 3.0	\$ 3.3	\$ 0.5
North Anna nuclear fuel	16.9	7.8	7.9	9.3	14.2	8.6
North Anna	2.6	15.6	8.9	18.1	20.9	23.0
Clover	7.4	1.3	2.6	1.4	5.0	0.7
Transmission	0.5	1.9	5.0	10.9	13.3	11.4
Combustion turbine facilities	2.3	2.7	2.7	0.6	10.5	6.9
Other	0.6	0.2	1.1	4.5	21.4	15.2
Total	<u>\$ 36.3</u>	<u>\$ 98.4</u>	<u>\$ 29.9</u>	<u>\$ 47.8</u>	<u>\$ 88.6</u>	<u>\$ 66.3</u>

Nearly all of our capital expenditures consist of additions to electric plant and equipment. Capital expenditures for North Anna include \$10.0 million, \$16.8 million, and \$17.4 million, for 2022, 2023, and 2024, respectively, for costs related to license extension. Projected capital expenditures for Transmission 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, distributed generation facilities, and energy storage. Projected capital expenditures for Other primarily relate to energy storage. We intend to use our cash flow from operations, borrowings under our revolving

credit facility, and, if needed, issuances of debt in the capital markets to fund all of our currently projected capital requirements through 2024.

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, 2021, we were not required to post collateral with counterparties pursuant to the power purchase and natural gas arrangements we have in place. 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, 2021, if our credit ratings had been below investment grade we estimate we would have been obligated to post between \$75 million and \$125 million of collateral with our counterparties. This calculation is based on power and natural gas prices on December 31, 2021, 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. S&P, Moody's, and Fitch currently rate our outstanding obligations issued under our Indenture at "A+," "A1," 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.

PJM requires that we provide collateral to support our obligations in connection with certain PJM transactions and as of December 31, 2021, we had posted collateral totaling \$5.2 million. In accordance with its credit policy, PJM subjects each 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, 2021, 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 \$19.6 million.

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 "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, 2021, 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 \$1.0 billion and \$1.1 billion. Approximately 42% of the fair value of this portfolio is estimable using observable market prices. The remaining 58% 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 58% 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 \$45.5 million as of December 31, 2021. 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 "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.

Interest Rate Risk and Equity Price Risk

In 2021, all of our outstanding long-term debt accrued interest at fixed rates.

We maintain a revolving credit facility. See “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. We did not have any borrowings outstanding under this facility as of December 31, 2021 and 2020; however, the interest rate on borrowings would have been 1.1%. As of December 31, 2021 and 2020, we had a \$0.5 million letter of credit outstanding under this facility. 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, 2021.

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, 2021, \$187.4 million, \$88.8 million, and \$0.5 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 debt and 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 debt and equity markets will not have a material impact on our financial results.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED FINANCIAL STATEMENTS INDEX

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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, 2021, 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, 2021, 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 United States generally accepted accounting principles.

March 16, 2022

/s/ MARCUS M. HARRIS

Marcus M. Harris
President and Chief Executive Officer

/s/ BRYAN S. ROGERS

Bryan S. Rogers
Senior Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To 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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2021, 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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of the critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for Asset Retirement and Environmental Obligations

*Description
of the
Matter*

At December 31, 2021, the Cooperative's nuclear asset retirement obligation ("ARO") at North Anna totaled \$161.5 million. As described in Note 3 to the consolidated financial statements, the Cooperative's ARO associated with the legal obligation to retire North Anna Unit 1 and Unit 2 is recognized at fair value when incurred and capitalized as part of the related long-lived asset. The ARO is based on estimates and assumptions including the cost and method of decommissioning and the timing of the related cash flows, and the license period of the nuclear plant including the probability of license extensions. New decommissioning studies are performed approximately every four years or whenever factors indicate that there could be a material change to the estimate. The Cooperative, with the assistance of third-party experts, performed an updated decommissioning study in 2019. The Cooperative is not aware of any events that have occurred since the 2019 study that would materially impact the ARO estimate.

Auditing the Cooperative's ARO was complex and highly judgmental due to the significant estimation required by management to determine the estimated present value of the legal obligation associated with the Cooperative's nuclear facility at North Anna. For example, the estimate was sensitive to significant assumptions including the method of decommissioning and timing of related cash flows. Significant changes in management's estimate could have a material effect on the Cooperative's results of operations.

*How We
Addressed
the Matter
in Our Audit*

To test the ARO estimate, our audit procedures included testing the significant assumptions and inputs including the timing of activities, projected license periods, and the method of decommissioning. For example, we compared current year regulatory requirements and recent market data to the information used by the Cooperative. We involved a specialist to assist in our evaluation of the factors discussed above that could impact the Cooperative's retirement obligation. We tested the completeness and accuracy of the underlying data.

/s/ Ernst & Young LLP

We have served as the Cooperative's auditor since 2000.

Richmond, Virginia

March 16, 2022

OLD DOMINION ELECTRIC COOPERATIVE

**CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2021 AND 2020**

	2021	2020
ASSETS:	(in thousands)	
Electric Plant:		
Property, plant, and equipment	\$ 2,542,407	\$2,536,395
Less accumulated depreciation	(1,049,756)	(984,076)
Net Property, plant, and equipment	1,492,651	1,552,319
Nuclear fuel, at amortized cost	14,495	17,321
Construction work in progress	48,956	38,810
Net Electric Plant	<u>1,556,102</u>	<u>1,608,450</u>
Investments:		
Nuclear decommissioning trust	276,658	242,337
Unrestricted investments and other	2,361	2,311
Total Investments	<u>279,019</u>	<u>244,648</u>
Current Assets:		
Cash and cash equivalents	107,852	9,288
Accounts receivable	13,821	16,909
Accounts receivable—members	63,037	79,813
Fuel, materials, and supplies	61,808	61,273
Deferred energy	5,005	—
Prepayments and other	10,757	5,598
Total Current Assets	<u>262,280</u>	<u>172,881</u>
Deferred Charges and Other Assets:		
Regulatory assets	22,253	31,131
Other assets	55,405	10,534
Total Deferred Charges and Other Assets	<u>77,658</u>	<u>41,665</u>
Total Assets	<u><u>\$ 2,175,059</u></u>	<u><u>\$2,067,644</u></u>
CAPITALIZATION AND LIABILITIES:		
Capitalization:		
Patronage capital	\$ 464,777	\$ 453,470
Non-controlling interest	5,831	5,853
Total Patronage capital and Non-controlling interest	470,608	459,323
Long-term debt	1,020,759	1,069,324
Total Capitalization	<u>1,491,367</u>	<u>1,528,647</u>
Current Liabilities:		
Long-term debt due within one year	49,041	49,041
Accounts payable	82,988	61,044
Accounts payable—members	112,742	70,546
Accrued expenses	6,128	6,292
Deferred energy	—	23,112
Total Current Liabilities	<u>250,899</u>	<u>210,035</u>
Deferred Credits and Other Liabilities:		
Asset retirement obligations	184,797	179,133
Regulatory liabilities	220,619	142,724
Other liabilities	27,377	7,105
Total Deferred Credits and Other Liabilities	<u>432,793</u>	<u>328,962</u>
Total Capitalization and Liabilities	<u><u>\$ 2,175,059</u></u>	<u><u>\$2,067,644</u></u>

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, 2021, 2020 AND 2019**

	<u>2021</u>	<u>2020</u>	<u>2019</u>
	(in thousands)		
Operating Revenues	\$ 780,640	\$ 807,704	\$ 932,682
Operating Expenses:			
Fuel	166,517	144,348	172,921
Purchased power	234,471	250,546	332,216
Transmission	131,290	128,427	159,995
Deferred energy	(28,116)	26,660	22,522
Operations and maintenance	78,294	61,518	74,647
Administrative and general	41,372	43,023	48,938
Depreciation and amortization	70,416	69,902	68,752
Amortization of regulatory asset/(liability), net	16,458	9,069	(35,056)
Accretion of asset retirement obligations	5,664	5,463	5,539
Taxes, other than income taxes	9,171	9,275	9,412
Total Operating Expenses	<u>725,537</u>	<u>748,231</u>	<u>859,886</u>
Operating Margin	55,103	59,473	72,796
Other income (expense), net	409	(105)	(162)
Investment income	20,162	13,106	7,188
Interest charges, net	(55,657)	(60,306)	(62,773)
Income taxes	8	(2)	(25)
Net Margin including Non-controlling interest	20,025	12,166	17,024
Non-controlling interest	22	(7)	(70)
Net Margin attributable to ODEC	20,047	12,159	16,954
Patronage Capital - Beginning of Period	453,470	441,311	428,663
Patronage Capital - Retirement	(8,740)	—	(4,306)
Patronage Capital - End of Period	<u>\$ 464,777</u>	<u>\$ 453,470</u>	<u>\$ 441,311</u>

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, 2021, 2020 AND 2019**

	<u>2021</u>	<u>2020</u>	<u>2019</u>
	(in thousands)		
Operating Activities:			
Net Margin including Non-controlling interest	\$ 20,025	\$ 12,166	\$ 17,024
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	70,416	69,902	68,752
Other non-cash charges	16,886	17,121	16,951
Change in current assets	14,170	16,799	(27,530)
Change in deferred energy	(28,117)	26,660	22,521
Change in current liabilities	56,303	23,284	(23,692)
Change in regulatory assets and liabilities	72,527	33,157	(58,590)
Change in deferred charges and other assets and deferred credits and other liabilities	(24,619)	(1,432)	2,575
Net Cash Provided by Operating Activities	<u>197,591</u>	<u>197,657</u>	<u>18,011</u>
Investing Activities:			
Purchases of held to maturity securities	—	—	(3,115)
Proceeds from sale of held to maturity securities	—	3,115	5,573
Purchases of available for sale securities	(15,000)	(24,800)	(53,828)
Proceeds from sale of available for sale securities	15,000	24,800	53,828
Increase in other investments	(20,105)	(12,561)	(5,636)
Electric plant additions	(29,881)	(98,395)	(36,263)
Net Cash Used for Investing Activities	<u>(49,986)</u>	<u>(107,841)</u>	<u>(39,441)</u>
Financing Activities:			
Debt issuance costs	—	(235)	(257)
Payments of long-term debt	(49,041)	(40,792)	(40,792)
Draws on revolving credit facility	—	355,225	274,000
Repayments on revolving credit facility	—	(422,425)	(206,800)
Net Cash (Used for) Provided by Financing Activities	<u>(49,041)</u>	<u>(108,227)</u>	<u>26,151</u>
Net Change in Cash and Cash Equivalents	98,564	(18,411)	4,721
Cash and Cash Equivalents - Beginning of Period	9,288	27,699	22,978
Cash and Cash Equivalents - End of Period	<u>\$ 107,852</u>	<u>\$ 9,288</u>	<u>\$ 27,699</u>

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

OLD DOMINION ELECTRIC COOPERATIVE

NOTES TO 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, 2021 and December 31, 2020. 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. In recent years, we have had no sales to TEC and TEC has had no sales to third parties. Additionally, we have a separate contract under which we may purchase natural gas from TEC; however, we have not purchased natural gas from TEC in recent years. 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.

The impact that the ongoing COVID-19 pandemic will have on our consolidated results of operations, financial condition, or cash flows is uncertain. We continue to actively manage our business to respond to this health crisis and will continue to evaluate the nature and extent of any impact.

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		
	2021	2020	2019
Wildcat Point	3.1%	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

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 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. 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, 2022, 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, 2021 and 2020, we had an outstanding receivable of \$2.4 million and \$3.2 million, respectively.

Fuel, Materials, and Supplies

Fuel, materials, and supplies is primarily composed of fuel and spare parts for our generating assets, renewable energy credits, and emission allowances, 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 2021, 2020, and 2019, was \$0.9 million, \$0.5 million, and \$0.5 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, 2021, 2020, and 2019.

Operating Revenues

Our operating revenues are derived from sales of power and renewable energy credits 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 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 and capacity 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 2021, 2020, and 2019, 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,		
	2021	2020	2019
	(in thousands)		
Revenues from sales to:			
Member distribution cooperatives			
Energy revenues	\$ 328,045	\$ 375,714	\$ 471,767
Renewable energy credits	36	33	26
Demand revenues	398,819	395,067	426,678
Total revenues from sales to member distribution cooperatives	<u>726,900</u>	<u>770,814</u>	<u>898,471</u>
Non-members			
Energy revenues	45,255	31,431	29,483
Renewable energy credits	8,485	5,438	4,672
Demand revenues	—	21	56
Total revenues from sales to non-members	<u>53,740</u>	<u>36,890</u>	<u>34,211</u>
Total operating revenues	<u>\$ 780,640</u>	<u>\$ 807,704</u>	<u>\$ 932,682</u>

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 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 of directors. 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 recover all of our costs and expenses or determines a change in cost allocation methodology among our member distribution cooperatives is appropriate, it may adopt a new formula to meet those costs and expenses, subject to any necessary regulatory review and approval. On June 26, 2020, we submitted an application to FERC to revise our formula rate for a change in cost allocation methodology of our remaining owned capacity service rate, to be effective January 1, 2021. On August 25, 2020, FERC issued an order accepting our filing with an effective date of January 1, 2021.

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,		
	2021	2020	2019
	(in thousands)		
Margin Stabilization adjustment	\$11,614	\$13,227	\$7,175

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 \$5.2 million and \$5.7 million as of December 31, 2021 and 2020, respectively, and are included as a direct reduction to long-term debt. Capitalized costs associated with our revolving credit facility totaled \$0.6 million and \$0.9 million as of December 31, 2021 and 2020, respectively, and are recorded in other assets. 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 revenues collected from our member distribution cooperatives and our energy expenses. 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, 2021 and 2020, we had an under-collected deferred energy balance of \$5.0 million and an over-collected deferred energy balance of \$23.1 million, respectively.

The following table summarizes the changes to our total energy rate since 2019, which were implemented to address the differences in our realized as well as projected energy costs:

Effective Date of Total Energy Rate Change	% Change
January 1, 2019	(1.3)
January 1, 2020	(16.2)
January 1, 2021	(15.9)
January 1, 2022	20.3

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 8—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 in other assets and other liabilities. 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 10—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 December 14, 2021, our board of directors approved an additional equity contribution of \$8.7 million, and subsequently declared a patronage capital retirement of \$8.7 million. As a result of the December 14, 2021 declaration, we reduced patronage capital and increased accounts payable—members by \$8.7 million. The \$8.7 million patronage capital retirement will be paid on March 25, 2022.

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 was paid on March 27, 2020.

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 \$63.0 million and \$79.8 million, as of December 31, 2021 and 2020, 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.

New Accounting Pronouncements

In March 2020, the FASB issued ASU 2020-04 Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting. The guidance provides temporary optional expedients and exceptions related to contract modifications and hedge accounting to ease entities' financial reporting burdens as the market transitions from the LIBOR and other interbank offered rates to alternative reference rates. The new guidance allows entities to elect not to apply certain modification accounting requirements, if certain criteria are met, to contracts affected by what the guidance calls reference rate reform. An entity that makes this election would consider changes in reference rates and other contract modifications related to reference rate reform to be events that do not require contract remeasurement at the modification date or reassessment of a previous accounting determination. The ASU notes that changes in contract terms that are made to effect the reference rate reform transition are considered related to the replacement of a reference rate if they are not the result of a business decision that is separate from or in addition to changes to the terms of a contract to effect that transition. The guidance is effective upon issuance and generally can be applied as of March 12, 2020 through December 31, 2022. We are continuing to evaluate the impact of this standard on our financial statements and currently do not anticipate a material impact from adopting this standard.

NOTE 2—Electric Plant

Our net electric plant was composed of the following as of December 31, 2021:

	Wildcat Point	North Anna	Clover	Combustion Turbine Facilities	Other	Total
	(in thousands)					
Property, plant, and equipment	\$877,789	\$ 416,259	\$ 707,333	\$ 440,168	\$100,858	\$ 2,542,407
Accumulated depreciation	(98,726)	(260,491)	(414,647)	(241,051)	(34,841)	(1,049,756)
Net Property, plant, and equipment	779,063	155,768	292,686	199,117	66,017	1,492,651
Nuclear fuel, at amortized cost	—	14,495	—	—	—	14,495
Construction work in progress	7	41,312	1,311	51	6,275	48,956
Net Electric Plant	<u>\$779,070</u>	<u>\$ 211,575</u>	<u>\$ 293,997</u>	<u>\$ 199,168</u>	<u>\$ 72,292</u>	<u>\$ 1,556,102</u>

Our net electric plant was composed of the following as of December 31, 2020:

	Wildcat Point	North Anna	Clover	Combustion Turbine Facilities	Other	Total
	(in thousands)					
Property, plant, and equipment	\$875,528	\$ 415,227	\$ 706,417	\$ 438,418	\$100,805	\$2,536,395
Accumulated depreciation	(71,656)	(249,546)	(401,363)	(228,378)	(33,133)	(984,076)
Net Property, plant, and equipment	803,872	165,681	305,054	210,040	67,672	1,552,319
Nuclear fuel, at amortized cost	—	17,321	—	—	—	17,321
Construction work in progress	989	34,961	1,110	—	1,750	38,810
Net Electric Plant	<u>\$804,861</u>	<u>\$ 217,963</u>	<u>\$ 306,164</u>	<u>\$ 210,040</u>	<u>\$ 69,422</u>	<u>\$1,608,450</u>

Wildcat Point

We own Wildcat Point, a 980 MW (net capacity entitlement) natural gas-fueled combined cycle generation facility. Wildcat Point achieved commercial operation on April 17, 2018.

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, 2021 and 2020, we had an outstanding accounts payable balance of \$7.9 million and \$3.8 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, 2021 and 2020, we had an outstanding accounts payable balance of \$5.5 million and \$2.1 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.

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, 2021 and 2020, our share of North Anna’s nuclear decommissioning asset retirement obligation totaled \$161.5 million and \$156.9 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 or that would have required an updated study to be performed in 2020. We are required to maintain a funded trust to satisfy our future obligation to decommission the North Anna facility. See Note 8—Investments.

The following represents changes in our asset retirement obligations for the years ended December 31, 2021 and 2020 (in thousands):

Asset retirement obligations as of December 31, 2019	\$ 173,669
Accretion expense	5,464
Asset retirement obligations as of December 31, 2020	\$ 179,133
Accretion expense	5,664
Asset retirement obligations as of December 31, 2021	<u>\$ 184,797</u>

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, submitted an application to the NRC in August 2020 for an additional 20-year operating license extension for North Anna. 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 9—Regulatory Assets and Liabilities.

NOTE 4—Power Purchase Agreements

In 2021, 2020, and 2019, our owned generating facilities together furnished approximately 55.6%, 52.0%, and 56.3%, respectively, of our energy requirements. The remaining needs were satisfied through purchases of power in the market 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. As of December 31, 2021, we were not required to post collateral and as of December 31, 2020, we had posted \$7.5 million. Additionally, PJM requires that we provide collateral to support our obligations in connection with certain PJM transactions. As of December 31, 2021 and 2020, we had posted \$5.2 million and \$1.2 million, respectively.

Our purchased power expense for 2021, 2020, and 2019 was \$234.5 million, \$250.5 million, and \$332.2 million, respectively.

As of December 31, 2021, our power purchase obligations under the various agreements were as follows:

<u>Year Ended December 31,</u>	Capacity and Energy Obligations
	(in millions)
2022	\$ 61.7
2023	50.2
2024	13.8
	<u>\$ 125.7</u>

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 less than 2.0% of our member distribution cooperatives' total energy requirements in 2021.

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 of demand and associated energy from owned generation or other suppliers. Such load can be returned to us with proper notice. 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, 2021, none of our member distribution cooperatives had utilized this latter exception.

If all of our member distribution cooperatives elected to fully 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.

<u>As of December 31,</u>	MW
2019	108
2020	111
2021	140

We do not anticipate that the current or potential full utilization of this exception or the return of load by our member distribution cooperatives will have a material impact on our results of operations, financial condition, 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.

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

	Year Ended December 31,		
	2021	2020	2019
	(in millions)		
Rappahannock Electric Cooperative	\$ 223.3	\$ 237.6	\$ 279.7
Shenandoah Valley Electric Cooperative	138.2	144.5	168.4
Delaware Electric Cooperative, Inc.	109.1	110.0	121.6
Choptank Electric Cooperative, Inc.	72.1	73.7	83.1
Southside Electric Cooperative	51.8	56.9	69.8
A&N Electric Cooperative	44.0	48.0	54.7
Mecklenburg Electric Cooperative	32.6	36.8	45.1
Prince George Electric Cooperative	20.2	22.9	26.9
Northern Neck Electric Cooperative	16.9	20.2	24.1
Community Electric Cooperative	10.5	11.0	14.1
BARC Electric Cooperative	8.2	9.2	11.0
Total	<u>\$ 726.9</u>	<u>\$ 770.8</u>	<u>\$ 898.5</u>

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, 2021 and 2020:

	December 31, 2021	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⁾	\$ 89,227	\$ 89,227	\$ —	\$ —
Nuclear decommissioning trust - net asset value ⁽¹⁾⁽²⁾	187,431	—	—	—
Unrestricted investments and other ⁽³⁾	212	—	212	—
Derivatives - gas and power ⁽⁴⁾	50,793	32,078	3,705	15,010
Total Financial Assets	\$ 327,663	\$ 121,305	\$ 3,917	\$ 15,010
Derivatives - gas and power ⁽⁴⁾	\$ 4,291	\$ —	\$ 4,291	\$ —
Total Financial Liabilities	\$ 4,291	\$ —	\$ 4,291	\$ —
(in thousands)				
	December 31, 2020	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⁾	\$ 76,037	\$ 76,037	\$ —	\$ —
Nuclear decommissioning trust - net asset value ⁽¹⁾⁽²⁾	166,300	—	—	—
Unrestricted investments and other ⁽³⁾	166	—	166	—
Derivatives - gas and power ⁽⁴⁾	3,478	1,582	480	1,416
Total Financial Assets	\$ 245,981	\$ 77,619	\$ 646	\$ 1,416
Derivatives - gas and power ⁽⁴⁾	\$ 6,406	\$ —	\$ 6,406	\$ —
Total Financial Liabilities	\$ 6,406	\$ —	\$ 6,406	\$ —

⁽¹⁾ For additional information about our nuclear decommissioning trust, see Note 8—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. Sensitivity in the market price of financial transmission rights could impact the fair value. For additional information about our derivative financial instruments, see Note 1—Summary of Significant Accounting Policies.

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:

Commodity	Unit of Measure	Quantity	
		As of December 31, 2021	As of December 31, 2020
Natural gas	MMBTU	58,640,000	55,630,000
Purchased power - financial transmission rights	MWh	9,156,789	6,922,373

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

Balance Sheet Location	Fair Value		
	As of December 31, 2021	As of December 31, 2020	
(in thousands)			
Derivatives in an asset position:			
Natural gas futures contracts	Other assets	\$ 35,783	\$ 2,062
Financial transmission rights	Other assets	15,010	1,416
Total derivatives in an asset position		<u>\$ 50,793</u>	<u>\$ 3,478</u>
Derivatives in a liability position:			
Natural gas futures contracts	Other liabilities	\$ 4,291	\$ 6,406
Total derivatives in a liability position		<u>\$ 4,291</u>	<u>\$ 6,406</u>

The Effect of Derivative Instruments on the Consolidated Statements of Revenues, Expenses, and Patronage Capital for the Years Ended December 31, 2021 and 2020

Derivatives Accounted for Utilizing Regulatory Accounting	Amount of Gain (Loss) Recognized in Regulatory Asset/Liability for Derivatives as of December 31,		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,	
	2021	2020		2021	2020
(in thousands)					
Natural gas futures contracts	\$ 34,703	\$ (5,043)	Fuel	\$ 26,758	\$ (37,242)
Purchased power	15,010	1,416	Purchased Power	9,463	(261)
Total	<u>\$ 49,713</u>	<u>\$ (3,627)</u>		<u>\$ 36,221</u>	<u>\$ (37,503)</u>

NOTE 8—Investments

Investments were as follows as of December 31, 2021 and 2020:

Description	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Carrying Value
			(in thousands)		
December 31, 2021					
Nuclear decommissioning trust ⁽¹⁾					
Debt securities	\$ 84,701	\$ 4,052	\$ —	\$ 88,753	\$ 88,753
Equity securities	92,916	94,923	(408)	187,431	187,431
Cash and other	474	—	—	474	474
Total Nuclear Decommissioning Trust	<u>\$ 178,091</u>	<u>\$ 98,975</u>	<u>\$ (408)</u>	<u>\$ 276,658</u>	<u>\$ 276,658</u>
Other					
Equity securities	\$ 157	\$ 55	\$ —	\$ 212	\$ 212
Non-marketable equity investments	2,149	2,370	—	4,519	2,149
Total Other	<u>\$ 2,306</u>	<u>\$ 2,425</u>	<u>\$ —</u>	<u>\$ 4,731</u>	<u>\$ 2,361</u>
					<u>\$ 279,019</u>
December 31, 2020					
Nuclear decommissioning trust ⁽¹⁾					
Debt securities	\$ 66,727	\$ 7,493	\$ —	\$ 74,220	\$ 74,220
Equity securities	89,472	76,828	—	166,300	166,300
Cash and other	1,817	—	—	1,817	1,817
Total Nuclear Decommissioning Trust	<u>\$ 158,016</u>	<u>\$ 84,321</u>	<u>\$ —</u>	<u>\$ 242,337</u>	<u>\$ 242,337</u>
Other					
Equity securities	\$ 132	\$ 34	\$ —	\$ 166	\$ 166
Non-marketable equity investments	2,145	2,340	—	4,485	2,145
Total Other	<u>\$ 2,277</u>	<u>\$ 2,374</u>	<u>\$ —</u>	<u>\$ 4,651</u>	<u>\$ 2,311</u>
					<u>\$ 244,648</u>

- ⁽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, 2021, were as follows:

Description	Less than 1 year	1-5 years	5-10 years	More than 10 years	Total
			(in thousands)		
Other ⁽¹⁾	\$ —	\$ —	\$ 88,753	\$ —	\$ 88,753
Total	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 88,753</u>	<u>\$ —</u>	<u>\$ 88,753</u>

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

NOTE 9—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, 2021 and 2020, were as follows:

	December 31,	
	2021	2020
	(in thousands)	
Regulatory Assets:		
Unamortized losses on reacquired debt	\$ 2,518	\$ 4,382
Deferred asset retirement costs	230	246
NOVEC contract termination fee	17,128	19,575
Interest rate hedge	1,604	1,754
Voluntary prepayment to NRECA Retirement Security Plan	773	1,547
Deferred net unrealized losses on derivative instruments	—	3,627
Total Regulatory Assets	\$ 22,253	\$ 31,131
Regulatory Assets included in Current Assets:		
Deferred energy	\$ 5,005	\$ —
Regulatory Liabilities:		
North Anna asset retirement obligation deferral	\$ 72,226	\$ 58,231
North Anna nuclear decommissioning trust unrealized gain (net of losses)	98,567	84,321
Unamortized gains on reacquired debt	113	172
Deferred net unrealized gains on derivative instruments	49,713	—
Total Regulatory Liabilities	\$ 220,619	\$ 142,724
Regulatory Liabilities included in Current Liabilities		
Deferred energy	\$ —	\$ 23,112

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.
- 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 12—Employee Benefit Plans.
- 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 revenues collected from our member distribution cooperatives and our energy expenses. 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 (net of losses) 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:

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

NOTE 10—Long-term Debt

Long-term debt consists of the following:

	December 31,	
	2021	2020
	(in thousands)	
\$250,000,000 principal amount of First Mortgage Bonds, 2017 Series A due 2037 at an interest rate of 3.33%	\$ 200,000	\$ 212,500
\$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%	57,000	60,000
\$165,000,000 principal amount of First Mortgage Bonds, 2011 Series B due 2040 at an interest rate of 5.54%	156,750	165,000
\$95,000,000 principal amount of First Mortgage Bonds, 2011 Series C due 2050 at an interest rate of 5.54%	68,875	71,250
\$250,000,000 principal amount of 2003 Series A Bonds due 2028 at an interest rate of 5.676%	72,912	83,328
\$300,000,000 principal amount of 2002 Series B Bonds due 2028 at an interest rate of 6.21%	87,500	100,000
	<u>1,075,037</u>	<u>1,124,078</u>
Debt issuance costs	(5,237)	(5,713)
Current maturities	(49,041)	(49,041)
	<u>\$ 1,020,759</u>	<u>\$ 1,069,324</u>

As of December 31, 2021 and 2020, deferred gains and losses on reacquired debt totaled a net loss of approximately \$2.4 million and \$4.2 million, respectively. Deferred gains and losses on reacquired debt are deferred under regulatory accounting. See Note 9—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)
2022	\$ 49,041
2023	49,041
2024	49,041
2025	49,041
2026	49,041
2027 and thereafter	829,832
	<u>\$ 1,075,037</u>

The aggregate fair value of long-term debt was \$1,292.5 million and \$1,374.8 million as of December 31, 2021 and 2020, 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 11—Liquidity Resources.

NOTE 11—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 totaled \$500 million through March 3, 2022, and \$400 million from March 4, 2022 through February 28, 2025. We did not have any borrowings outstanding under this facility as of December 31, 2021 and 2020; however, the interest rate on borrowings would have been 1.1%. As of December 31, 2021 and 2020, we had a \$0.5 million letter of credit outstanding under this facility.

Borrowings under the syndicated 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 syndicated credit agreement contains customary conditions to borrowing or the issuance of letters of credit, representations and warranties, and covenants. This 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). Outstanding loans under this 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, 2021 and 2020, were \$92.3 million and \$57.2 million, respectively. Amounts extended to our member distribution cooperatives are included in accounts receivable—members and as of December 31, 2021 there were no amounts extended and as of December 31, 2020, the amounts extended to our member distribution cooperatives was \$6.5 million.

NOTE 12—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, 2021 and 2020, 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 2021.

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 \$4.0 million, \$4.0 million, and \$3.7 million in 2021, 2020, and 2019, 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 \$0.3 million in other liabilities.

Pension expense, inclusive of administrative fees, was \$5.5 million, \$5.1 million, and \$4.7 million for 2021, 2020, and 2019, respectively. Pension expense for 2021, 2020, and 2019 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 2021, 2020, and 2019.

NOTE 13—Supplemental Cash Flows Information

Cash paid for interest, net of amounts capitalized, in 2021, 2020, and 2019, was \$53.3 million, \$57.9 million, and \$60.3 million, respectively. Cash paid for income taxes was immaterial in 2021, 2020, and 2019. Accrued capital expenditures in 2021, 2020, and 2019 were \$2.7 million, \$3.8 million, and \$69.8 million, respectively.

NOTE 14—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 \$13.5 billion of liability protection on a per site, per nuclear incident basis, via obligations required of owners of nuclear power plants, and allows for an inflationary adjustment every five years. During the first quarter of 2021, the total liability protection per nuclear incident available to all participants in the secondary financial protection program decreased from \$13.8 billion to \$13.7 billion. During the second quarter of 2021, the total liability protection per nuclear incident available to all participants in the secondary financial protection program decreased from \$13.7 billion to \$13.5 billion. These decreases do 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 \$34.9 million as of December 31, 2021.

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.

Management's Annual Report on Internal Control over Financial Reporting

Our management has assessed our internal control over financial reporting as of December 31, 2021, 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, 2021, 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

There were no material changes that occurred during the last fiscal year that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We have not identified any adverse impact on our internal control over financial reporting despite the majority of our headquarters personnel telecommuting due to the COVID-19 pandemic. The design of our processes and controls allows for remote execution with accessibility to secure data. We are continually monitoring and assessing the ongoing COVID-19 situation to minimize the impact, if any, on the design and operating effectiveness on our internal controls.

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. The other candidate must be either a director or employee of the member distribution cooperative. Currently and historically, this other candidate is the CEO of that member distribution cooperative. As a result, each of the candidates for director on our board has a developed understanding of the issues affecting electric cooperatives and the provision of electric services based on many years of industry experience. 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, including principal occupation and employment during the past five years, qualifications in addition to those referred to above, and directorships in public corporations, if any, is listed below.

Christopher S. Botulinski (49). Interim CEO of BARC Electric Cooperative since December 2021 and COO of BARC Electric Cooperative since April 2021. Mr. Botulinski served as Vice President of Engineering at Southwestern Electric Cooperative, Inc. from January 2017 to April 2021. Mr. Botulinski has been a director of ODEC since December 2021.

Michael K. Brown (62). Executive Director of the National Association of State Conservation Agencies since 2010. Mr. Brown has been a director of ODEC since January 2022, and a director of Delaware Electric Cooperative, Inc. since 2011.

Paul H. Brown (76). 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 2008.

John J. Burke, Jr. (65). 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 (75). 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. (78). 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 (70). 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 (58). President and CEO of Southside Electric Cooperative since 2007. Mr. Edwards has been a director of ODEC since 2007.

Chad N. Fowler (43). 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. (76). 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 (60). President and CEO of Community Electric Cooperative since 2013. Mr. Harmon has been a director of ODEC since 2013.

John D. Hewa, Jr. (49). President and CEO of Rappahannock Electric Cooperative since August 2020. Mr. Hewa served as COO of Rappahannock Electric Cooperative from January 2020 to August 2020 and served as Vice President Corporate Services from July 2017 to December 2019. Mr. Hewa served as CEO of Pedernales Electric Cooperative, Inc. from July 2013 to May 2017. Mr. Hewa has been a director of ODEC since September 2020.

Bradley H. Hicks (51). President and CEO of Northern Neck Electric Cooperative since June 2020. Mr. Hicks served as President and CEO of Habersham EMC from October 2017 to September 2019. Mr. Hicks served as Vice President, Engineering and Energy Innovations at Pedernales Electric Cooperative, Inc. from January 2014 to June 2017. Mr. Hicks has been a director of ODEC since July 2020.

David J. Jones (73). 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.

John C. Lee, Jr. (61). President and CEO of Mecklenburg Electric Cooperative since 2008. Mr. Lee has been a director of ODEC since 2008.

Cary J. Logan, Jr. (42). 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. Mr. Logan has been a director of ODEC since April 2019.

Micheal E. Malandro (45). 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. Mr. Malandro has been a director of ODEC since 2015.

Suzanne S. Obenshain (59). Owner of SBVA Properties, LLC. since May 2005. Ms. Obenshain has been a director of ODEC since July 2020 and a director of Shenandoah Valley Electric Cooperative since 2016.

Gregory S. Rogers (55). President and CEO of Shenandoah Valley Electric Cooperative since July 2020. Mr. Rogers served as Acting CEO of Shenandoah Valley Electric Cooperative from April 2020 to July 2020 and as Vice President of Engineering and Operations from September 2016 to April 2020. Mr. Rogers has been a director of ODEC since May 2020.

Gregory J. Starheim (59). President and CEO of Delaware Electric Cooperative, Inc. since July 2021. Mr. Starheim served as Senior Vice President of National Rural Utilities Cooperative Finance Corporation from July 2015 to May 2021. Mr. Starheim has been a director of ODEC since August 2021.

Keith L. Swisher (67). 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.

Belvin Williamson, Jr. (58). President and CEO of A&N Electric Cooperative since 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 cumulative experience all 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 meets regularly with

our independent public accounting firm regarding our financial reporting, internal controls over financial reporting, and other related matters, and 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, their respective ages, positions, and relevant business experience are listed below.

Marcus M. Harris (49). President and Chief Executive Officer of ODEC since April 2018. Mr. Harris served as Executive Vice President and CEO at Kansas Electric Power Cooperative from 2014 to March 2018.

Bryan S. Rogers (53). Senior Vice President and Chief Financial Officer since July 2018. Mr. Rogers joined ODEC in 1996 and has held various accounting positions, including Vice President and Controller from 2007 to June 2018.

D. Richard Beam (64). Senior Vice President and Chief Operating Officer since January 2019. Mr. Beam joined ODEC in 1987 and has held various power supply positions, including Senior Vice President of Power Supply from 2013 to December 2018. Mr. Beam retired on March 1, 2022.

Micheal L. Hern (66). Senior Vice President and Chief Legal Officer 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 performed legal services as outside general counsel to ODEC.

Kirk D. Johnson (52). Senior Vice President of Member Engagement since February 2019. Mr. Johnson served as Senior Vice President of Government Relations at NRECA from 2011 to January 2019.

Effective March 2, 2022, Mr. Christopher F. Cosby was promoted to Senior Vice President of Power Supply.

Christopher F. Cosby (47). Senior Vice President of Power Supply beginning March 2, 2022. Mr. Cosby held the position of Vice President of Regulatory Affairs from January 2021 to March 1, 2022 and held the position of Director of Asset Management from April 2018 to January 2021. Mr. Cosby served as North America Steam and Boiler Portfolio Program Manager at General Electric Company from May 2016 to April 2018.

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.

Named Executive Officers

For fiscal year 2021, our named executive officers (“NEOs”) include the following five individuals:

- Marcus M. Harris, President and Chief Executive Officer
- Bryan S. Rogers, Senior Vice President and Chief Financial Officer
- D. Richard Beam, Senior Vice President and Chief Operating Officer
- Micheal L. Hern, Senior Vice President and Chief Legal Officer
- Kirk D. Johnson, Senior Vice President of Member Engagement

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 a third party through a national compensation survey. 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, created a performance appraisal instrument for the President and CEO position.

Process for Determining NEO Compensation

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.

Cash 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. Mr. Rogers was awarded a \$2,000 bonus in 2021.

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 severance are set forth in his employment agreement. See "Employment Agreement" below. Other than our President and CEO, none of our 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 2021, employees could elect to have up to 100% or \$19,500, 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 2021 was \$6,500.

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 Deferred Compensation Plan as well as an annual contribution, if any, up to the maximum amount permitted under IRC Section 457(b). Employees with the title of Vice President and above may participate in this plan. We made a \$19,500 contribution to the plan for the benefit of our President and CEO in 2021. 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. We participate in the Executive Benefit Restoration Plan and our President and CEO, Senior Vice President and CFO, Senior Vice President and CLO, and Senior Vice President of Member Engagement are currently the only participants in this plan. Our Senior Vice President and COO participated 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 \$3,837 in 2021.

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, fitness facility 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 NEOs 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 NEOs 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 served.

SUMMARY COMPENSATION

Name and Principal Position	Year	Salary	Bonus	Change in Pension Value and Non-qualified Deferred Compensation Earnings ⁽¹⁾	All Other Compensation ⁽²⁾	Total
Marcus M. Harris President and CEO	2021	\$ 786,625	\$ —	\$ 272,482	\$ 29,137	\$1,088,244
	2020	775,000	—	191,296	33,389	999,685
	2019	675,000	—	83,835	25,872	784,707
Bryan S. Rogers Senior Vice President and CFO	2021	337,366	2,000	485,560	5,800	830,726
	2020	332,380	3,000	409,975	5,700	751,055
	2019	316,103	—	41,571	5,600	363,274
D. Richard Beam Senior Vice President and COO	2021	352,739	—	349,137	5,800	707,676
	2020	347,526	3,000	419,008	5,700	775,234
	2019	337,404	—	55,076	5,600	398,080
Micheal L. Hern ⁽³⁾ Senior Vice President and Chief Legal Officer	2021	313,635	—	99,505	5,800	418,940
	2020	309,000	—	35,429	2,615	347,044
	2019	124,615	—	—	—	124,615
Kirk D. Johnson ⁽⁴⁾ Senior Vice President of Member Engagement	2021	344,999	—	319,797	5,800	670,596
	2020	339,900	—	352,259	5,700	697,859
	2019	279,231	—	86,147	27,139	392,517

⁽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, Mr. Rogers, Mr. Hern, and Mr. Johnson, also includes benefits under the Executive Benefit Restoration Plan.

⁽²⁾ See the All Other Compensation table below.

⁽³⁾ Mr. Hern joined ODEC on July 31, 2019. Accordingly, his compensation for 2019 includes only the compensation received by Mr. Hern after such date.

⁽⁴⁾ Mr. Johnson joined ODEC on February 25, 2019. Accordingly, his compensation for 2019 includes only the compensation received by Mr. Johnson after such date.

The following table sets forth information concerning all other compensation awarded to, earned by, or paid to our NEOs during 2021.

ALL OTHER COMPENSATION

Name	Matching Contributions under 401(k) Plan	Contributions under Deferred Compensation Plan	Perquisites and other personal benefits ⁽¹⁾	Total
Marcus M. Harris	\$ 5,800	\$ 19,500	\$ 3,837	\$ 29,137
Bryan S. Rogers	5,800	—	—	5,800
D. Richard Beam	5,800	—	—	5,800
Micheal L. Hern	5,800	—	—	5,800
Kirk D. Johnson	5,800	—	—	5,800

⁽¹⁾ For Mr. Harris, includes the personal use of a company automobile.

Potential Payments upon Termination or Change in Control

Except for Mr. Harris, none of our NEOs have any contractual termination benefits other than as provided under the retirement plans in which they participate and none of our NEOs 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 NEOs 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 would 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 2021, ODEC made a contribution of \$19,500 to the Deferred Compensation Plan for the benefit of 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, 2021, 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:

Cash severance	\$ 786,625
Medical Insurance	22,302
Total	<u>\$ 808,927</u>

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, 2021, 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, 2021. As a result of changes in Internal Revenue Service regulations, the base annual salary used in determining benefits was limited to \$290,000, effective January 1, 2021.

PENSION BENEFITS ⁽¹⁾

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Year
Marcus M. Harris ⁽²⁾	NRECA Retirement Security Plan	6.00	\$ 378,414	\$ —
	Executive Benefit Restoration Plan	3.67	289,495	—
Bryan S. Rogers	NRECA Retirement Security Plan	24.33	1,727,505	—
	Executive Benefit Restoration Plan	24.33	109,691	—
D. Richard Beam	NRECA Retirement Security Plan	34.33	2,819,294	—
	Deferred Compensation Pension Restoration Plan	34.33	—	410,455
Micheal L. Hern	NRECA Retirement Security Plan	1.42	127,401	—
	Executive Benefit Restoration Plan	1.42	7,533	—
Kirk D. Johnson ⁽³⁾	NRECA Retirement Security Plan	19.00	1,399,589	—
	Executive Benefit Restoration Plan	2.92	57,675	—

⁽¹⁾ Numerical amounts in this table were computed as of December 31, 2021, and the present value amounts were determined using the same assumptions used for financial reporting purposes.

⁽²⁾ 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 3.67 years of credited service with ODEC.

⁽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 2.92 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 under the plan, 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 (1.62% for 2021) and the PPA three segment yield rates (0.53%, 2.31%, and 3.09% for 2021) 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 2021 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.

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 determined that, beginning in 2019, employees with the title of Vice

President and above may participate in this plan. In 2021, Mr. Harris was the only NEO who participated in the plan. Under the Deferred Compensation Plan, Mr. Harris' annual deferrals cannot exceed the lesser of 100% of Mr. Harris' annual compensation or \$19,500 for 2021, 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 NEOs in 2021:

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	\$ —	\$ 19,500	\$ 23,164	\$ —	\$ 208,883
Bryan S. Rogers	—	—	—	—	—
D. Richard Beam	—	—	—	—	—
Micheal L. Hern	—	—	—	—	—
Kirk D. Johnson	—	—	—	—	—

(1) For Mr. Harris, includes a \$19,500 ODEC contribution to the Deferred Compensation Plan, which is included 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 \$51,604 which was previously reported as compensation to Mr. Harris in our Summary Compensation Table for fiscal years prior to fiscal year 2021.

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 2021, 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 2021:

DIRECTOR COMPENSATION

Name	Fees Earned or Paid in Cash	Total
Paul H. Brown	\$ 45,600	\$ 45,600
John J. Burke, Jr.	46,100	46,100
Darlene H. Carpenter	46,100	46,100
Earl C. Currin, Jr.	45,600	45,600
E. Garrison Drummond	45,600	45,600
Chad N. Fowler	45,600	45,600
Hunter R. Greenlaw, Jr.	47,350	47,350
Bruce A. Henry	45,600	45,600
David J. Jones	46,350	46,350
Suzanne S. Obenshain	45,600	45,600
Keith L. Swisher	45,600	45,600
	<u>\$ 505,100</u>	<u>\$ 505,100</u>

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 exception 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. 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 CEO 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 \$1,088,244 in 2021. Based on reasonable estimates, the median annual total compensation of all of our employees, excluding our President and CEO, was \$165,052 for 2021. Accordingly, for 2021, 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 6.6 to 1.

We identified our median employee based on salary earned in 2021 by each individual who was employed by us on November 15, 2021. 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.

John C. Lee, Jr., Chair
E. Garrison Drummond
Jeffrey S. Edwards
Chad N. Fowler
Micheal E. Malandro
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 listing standards.

There are no related person transactions in 2021 that the SEC would require to be reported under its rules.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Ernst & Young LLP served as our independent registered public accounting firm during 2021. 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.

	<u>2021</u>	<u>2020</u>
Audit Fees ⁽¹⁾	\$ 368,740	\$ 368,740
Audit-Related Fees ⁽²⁾	—	3,000
Tax Fees ⁽³⁾	9,939	8,704
All Other Fees	—	—
Total	<u>\$ 378,679</u>	<u>\$ 380,444</u>

- (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 2021 and 2020, 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 2021 and 2020, 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 43
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 \(filed as exhibit 10.1 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992\). \(P\)](#)

[*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 \(filed as exhibit 10.2 to the Registrant's Form S-1 Registration Statement, File No. 33-46795, filed on March 27, 1992\). \(P\)](#)

*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). (P)

*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). (P)

*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). (P)

*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). (P)

*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 Employment letter, dated January 14, 2022, of Old Dominion Electric Cooperative and agreed and accepted by Christopher F. Cosby.

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

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

[*†10.20 Executive Benefit Restoration Plan effective April 9, 2019 \(filed as exhibit 10.19 to the Registrant’s Form 10-K for the year ended December 31, 2019, File No. 000-50039, on March 11, 2020\).](#)

*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). (P)

[*10.21 Extension Agreement \(filed as exhibit 10.21 to the Registrant’ Form 10-K for the year ended December 31, 2019, File No. 000-50039, on March 11, 2020\).](#)

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 Inline XBRL Instance Document (the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)

101.SCH Inline XBRL Taxonomy Extension Schema Document

101.CAL Inline XBRL Taxonomy Extension Calculation Linkbase Document

101.LAB Inline XBRL Taxonomy Extension Label Linkbase Document

101.PRE Inline XBRL Taxonomy Extension Presentation Linkbase Document

101.DEF Inline XBRL Taxonomy Extension Definition Linkbase Document

104 Cover Page Interactive Data File (formatted as inline XBRL and contained in Exhibit 101)

* 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 other compensatory plan or arrangement.

(P) Paper exhibits.

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 16, 2022

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

<u>/s/ STEVEN A. HARMON</u> Steven A. Harmon	Director
<u>/s/ JOHN D. HEWA, JR.</u> John D. Hewa, Jr.	Director
<u>/s/ BRADLEY H. HICKS</u> Bradley H. Hicks	Director
<u>/s/ DAVID J. JONES</u> David J. Jones	Director
<u>/s/ JOHN C. LEE, JR.</u> John C. Lee, Jr.	Director
<u>/s/ CARY J. LOGAN, JR.</u> Cary J. Logan, Jr.	Director
<u>/s/ MICHEAL E. MALANDRO</u> Micheal E. Malandro	Director
<u>/s/ SUZANNE S. OBENSHAIN</u> Suzanne S. Obenshain	Director
<u>/s/ GREGORY S. ROGERS</u> Gregory S. Rogers	Director
<u>/s/ GREGORY J. STARHEIM</u> Gregory J. Starheim	Director
<u>/s/ KEITH L. SWISHER</u> Keith L. Swisher	Director
<u>/s/ BELVIN WILLIAMSON, JR.</u> 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 2021. Accordingly, ODEC will not file an annual report with the Securities and Exchange Commission.

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 16, 2022

/s/ MARCUS M. HARRIS

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

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 16, 2022

/s/ BRYAN S. ROGERS

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

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-K for the period ending December 31, 2021 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 16, 2022

/s/ MARCUS M. HARRIS

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

OLD DOMINION ELECTRIC COOPERATIVE
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Old Dominion Electric Cooperative (the “Company”) on Form 10-K for the period ending December 31, 2021 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 16, 2022

/s/ BRYAN S. ROGERS

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