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

FORM 10-K

☒ **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**

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
001-41137	CONSTELLATION ENERGY CORPORATION (a Pennsylvania corporation) 1310 Point Street Baltimore, Maryland 21231-3380 (610) 765-5959	87-1210716
333-85496	CONSTELLATION ENERGY GENERATION, LLC (a Pennsylvania limited liability company) 200 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
CONSTELLATION ENERGY CORPORATION:		
Common Stock, without par value	CEG	The Nasdaq Stock Market LLC

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.

Constellation Energy Corporation	Yes ☐	No ☒
Constellation Energy Generation, LLC	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 Act.

Constellation Energy Corporation	Yes ☐	No ☒
Constellation Energy Generation, LLC	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 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.

Constellation Energy Corporation	Yes ☐	No ☒
Constellation Energy Generation, LLC	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 and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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.

Constellation Energy Corporation	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
Constellation Energy Generation, LLC	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 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 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 Rule 12b-2 of the Act). Yes ☐ No ☒

Prior to the separation of registrants from Exelon Corporation on February 1, 2022, the registrants were wholly owned subsidiaries of Exelon Corporation. Consequently, there was no aggregate market value of common stock held by non-affiliates of the registrants as of June 30, 2021, the last business day of the registrants’ most recently completed second fiscal quarter.

The number of shares outstanding of each registrant’s common stock as of February 1, 2022 was as follows:

Constellation Energy Corporation Common Stock, without par value	326,663,937
Constellation Energy Generation, LLC	Not applicable

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GLOSSARY OF TERMS AND ABBREVIATIONS

Constellation Energy Corporation and Related Entities	
CEG Parent	Constellation Energy Corporation
Constellation	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC)
Registrants	CEG Parent and Constellation, collectively
Exelon	Exelon Corporation
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
Antelope Valley	Antelope Valley Solar Ranch One
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
CR	Constellation Renewables, LLC (formerly ExGen Renewables IV, LLC)
CRP	Constellation Renewables Partners, LLC (formerly ExGen Renewables Partners, LLC)
FitzPatrick	James A. FitzPatrick nuclear generating station
Ginna	R. E. Ginna nuclear generating station
NER	NewEnergy Receivables LLC
NMP	Nine Mile Point nuclear generating station
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
RPG	Renewable Power Generation, LLC
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASA	Asset Sale Agreement
Bcf	Billion cubic feet
Brookfield Renewable	Brookfield Renewable Partners, L.P.
CAIDI	Customer Average Interruption Duration Index
CAISO	California ISO
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
C&I	Commercial and Industrial
Clean Air Act	Clean Air Act of 1963, as amended
Clean Energy Law	Illinois Public Act 102-0062 signed into law on September 15, 2021
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CMC	Carbon Mitigation Credit
CODM	Chief Operating Decision Maker
CORe	Constellation Offsite Renewables
DCPSC	District of Columbia Public Service Commission
DEPSC	Delaware Public Service Commission
DOE	United States Department of Energy
DOEE	Department of Energy & Environment
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
EDF	Electricite de France SA and its subsidiaries
EFEC	Emissions-Free Energy Certificate
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
ESG	Environmental, Social, and Governance
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
Form 10	Amendment Number 2 to our General Form for Registration of Securities on Form 10, filed with the SEC on December 20, 2021 and declared effective by the SEC on December 29, 2021, as supplemented by Exhibit 99.1 to our Current Report on Form 8-K, filed with the SEC on January 28, 2022.
Former PECO Units	Limerick, Peach Bottom, and Salem nuclear generating units
Former ComEd Units	Braidwood, Byron, Dresden, LaSalle and Quad Cities nuclear generating units
FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas

GWh	Gigawatt hour
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LIPA	Long Island Power Authority
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Standards
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MOPR	Minimum Offer Price Rule
MPSC	Missouri Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange, Inc.
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchase Normal Sale scope exception
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PCAOB	Public Company Accounting Oversight Board
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSDAR	Post-shutdown Decommissioning Activities Report

PSEG	Public Service Enterprise Group Incorporated
PUCT	Public Utility Commission of Texas
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RIN	Renewable Identification Number
RMC	Risk Management Committee
RNF	Revenue Net of Purchased Power and Fuel Expense
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Energy Portfolio Standards
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SAIFI	System Average Interruption Frequency Index
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOFR	Secured Overnight Financing Rate
SOS	Standard Offer Service
SPP	Southwest Power Pool
STEM	Science, Technology, Engineering, and Mathematics
TWh	Terawatt-hour
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by Constellation Energy Corporation and Constellation Energy Generation, LLC, (Registrants). Information contained herein relating to any individual Registrant is filed by the Registrant on its own behalf.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic and financial performance, are intended to identify such forward-looking statements.

The factors that could cause actual results to differ materially from the forward-looking statements made by us include those factors discussed herein, including those factors discussed in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 19, Commitments and Contingencies, and (d) other factors discussed in filings with the SEC. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements, and other information that we file electronically with the SEC. These documents are also available to the public from commercial document retrieval services and our website at www.ConstellationEnergy.com. Information contained on our website shall not be deemed incorporated into, or to be a part of, this Report.

PART I

ITEM 1.

General

On February 21, 2021, the board of directors of Exelon Corporation ("Exelon") authorized management to pursue a plan to separate its competitive generation and customer-facing energy businesses, conducted through Constellation Energy Generation, LLC ("Constellation", formerly Exelon Generation Company, LLC) and its subsidiaries, into an independent, publicly traded company. Constellation Energy Corporation ("CEG Parent" or the "Company"), a Pennsylvania corporation and a direct, wholly owned subsidiary of Exelon, was newly formed for the purpose of separation and had not engaged in any activities except in preparation for the distribution. On February 1, 2022, Exelon completed the separation by distributing all the outstanding shares of the Company's common stock, on a pro rata basis to the holders of Exelon's common stock, with the Company holding all the interests in Constellation previously held by Exelon. As of 2002, Constellation has been an individual registrant since the registration of their public debt securities under the Securities Act. As an individual registrant, Constellation has historically filed consolidated financial statements to reflect their financial position and operating results as a stand-alone, wholly owned subsidiary of Exelon. The consolidated financial information presented in this Annual Report on Form 10-K for 2021 represents twelve months of information for Constellation.

References in this report to "we," "our," "us" and "the Company" are to Constellation and/or its subsidiaries, as apparent in the context. See Glossary for defined terms.

Our Business

We are America's leading clean energy company, based on the production of carbon-free electricity. We are the largest supplier of clean energy and sustainable solutions to homes, businesses, governments, community aggregations and a range of wholesale customers (such as municipalities, cooperatives, and other strategics) across the continental U.S., backed by approximately 32,400 megawatts of generating capacity consisting of nuclear, wind, solar, natural gas and hydroelectric assets. We produced nearly 10% of the nation's carbon-free energy (based on generation output of electricity) based on published reports on energy delivery by the U.S. Energy Information Administration, making us an important partner to businesses and state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis. We operate in 48 states, Canada and now employ approximately 12,700 people after separation.

We are differentiated by owning the cleanest generation fleet in the country. We are committed to a clean energy future, and we believe our generation fleet is essential to helping meet clean energy targets, at both the state and national level. We are uniquely positioned through the pairing of our clean energy fleet with our customer-facing business. Our customer-facing business is one of the nation's largest competitive energy suppliers, offering innovative options along the sustainability continuum to meet customer clean energy and climate goals.

Our Operations

We operate the largest carbon-free generation fleet in the nation and are one of the largest competitive electric generation companies in the country, as measured by owned and contracted MW. Collectively, the combined fleet is nearly 90% carbon-free (based on generation output of electricity) and is the fourth largest generation portfolio in the U.S. in terms of total generation with meaningful geographic diversity.

At December 31, 2021, our generating resources consisted of the following:

Type of Capacity	MW
Owned generation assets[(a)]	
Nuclear	20,899
Natural gas and oil	8,819
Renewable[(b)]	2,682
Owned generation assets	32,400
Contracted generation[(c)]	4,102
Total generating resources	36,502

(a) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES for additional information.
(b) Includes wind, hydroelectric, and solar generating assets.
(c) Electric supply procured under unit-specific agreements.

The following map illustrates the locations of our generation facilities as of December 31, 2021:

The Company's Generation Fleet Map[(a)]

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Owned Assets[(b)]

Nuclear
Wind
Gas/Other
Solar
Hydro
Other Renewables

(a) Note: One symbol is included per location. Some locations may have multiple generating units. Locations in tight geographic proximity may appear as one symbol. Units that are not currently operational are not captured.
(b) Does not reflect Grand Prairie Generating Station (Gas/other), located in Alberta, Canada.

We have five reportable segments, as described in the table below, representing the different geographical areas in which our owned generating resources are located, and our customer-facing activities are conducted.

Segment	Net Generation Capacity (MW)[(a)]	% of Net Generation Capacity	Geographical Area
Mid-Atlantic	10,508	32 %	Eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina
Midwest	11,898	37 %	Western half of PJM and the United States footprint of MISO, excluding MISO's Southern Region
New York	3,093	10 %	NYISO
ERCOT	3,610	11 %	Electric Reliability Council of Texas
Other Power Regions	3,291	10 %	New England, South, West, and Canada
Total	32,400	100 %	

(a) Net generation capacity is stated at proportionate ownership share as of December 31, 2021. See ITEM 2. PROPERTIES for additional information.

The following table shows sources of electric supply in GWh for 2021 and 2020:

	Source of Electric Supply	
	2021	2020
Nuclear[(a)]	174,987	175,085
Purchases — non-trading portfolio	67,605	79,972
Natural gas and oil	19,960	19,501
Renewable[(b)]	6,577	7,052
Total Supply	269,129	281,610

(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants and includes the total output of plans that are fully consolidated.
(b) Includes wind, hydroelectric, solar, and biomass generating assets.

Nuclear Facilities

Our nuclear fleet is the nation's largest with current generating capacity of approximately 21 gigawatts; it produced 175 terawatt hours of zero-emissions electricity during 2021 – enough to power 14.9 million homes and avoid more than 124 million metric tons of carbon emissions according to the US EPA GHG Equivalencies Calculator. We have ownership interests in 13 nuclear generating stations currently in service, consisting of 23 units. As of December 31, 2021, we wholly own all our nuclear generating stations, except for undivided ownership interests in four jointly owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), Salem (42.59% ownership), and Nine Mile Point Unit 2 (82% ownership), which are consolidated in our financial statements relative to our proportionate ownership interest in each unit. See ITEM 2. PROPERTIES for additional information on our nuclear facilities.

On August 6, 2021, Constellation and EDF entered into a settlement agreement pursuant to which we, through a wholly owned subsidiary, purchased EDF's equity interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to the 82% undivided ownership interest in Nine Mile Point Unit 2. Prior to August 6, 2021, we had a 50.01% membership interest in CENG, however CENG is consolidated within our results for all periods presented. See Note 2 — Mergers, Acquisitions, and Dispositions and Note 21 — Variable Interest Entities of the Notes to Consolidated Financial Statements for additional information regarding the acquisition of EDF's equity interest in CENG and the CENG consolidation.

We operate all of these nuclear generating stations, except for the two units at Salem, which are operated by PSEG Nuclear, LLC (an indirect, wholly owned subsidiary of PSEG), and we have consistently operated our nuclear plants at best-in-class levels. During 2021, 2020, and 2019, our nuclear generating facilities achieved capacity factors[(a)] of 94.5%, 95.4%, and 95.7%, respectively, at ownership percentage. More broadly, the nuclear capacity factor has been approximately four percentage points better than the industry average annually since 2013.

Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on our results of operations. In 2021, we achieved an average refueling outage duration of 22 days for units we operate. During 2020, and 2019, we achieved an average refueling outage duration of 22 days and 21 days against an industry average of 34 and 36 days, respectively.

We manage our scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for our wholesale and retail power marketing activities. In 2021, 2020, and 2019 electric supply (in GWh) generated from our nuclear generating facilities was 65%, 62%, and 64%, respectively, of our total electric supply, which also includes natural gas, oil, and renewable generation and electric supply purchased for resale. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on electric supply sources.

During scheduled refueling outages, we perform maintenance and equipment upgrades in order to maintain safe, reliable operations and to minimize the occurrence of unplanned outages. In addition to the maintenance and equipment upgrades performed by us during scheduled refueling outages, we have extensive operating and security procedures in place to ensure the safe operation of our nuclear units. We also have extensive safety systems in place to protect the plant, personnel, and surrounding area in the unlikely event of an accident or other incident.

We have original 40-year operating licenses from the NRC for each of our nuclear units and have received 20-year operating license renewals from the NRC for all our nuclear units except Clinton. PSEG has received 20-year operating license renewals for Salem Units 1 and 2. Peach Bottom has received a second 20-year license renewal from the NRC, for a total 80-year term, for Units 2 and 3.

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(a) Capacity factor is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information.

The following table summarizes the current license expiration dates for our nuclear facilities currently in service:

Station	Unit	In-Service Date[(a)]	Current License Expiration
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton[(b)]	1	1987	2027
Dresden	2	1970	2029
	3	1971	2031
FitzPatrick	1	1975	2034
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Peach Bottom	2	1974	2053
	3	1974	2054
Quad Cities	1	1973	2032
	2	1973	2032
Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040

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(a) Denotes year in which nuclear unit began commercial operations.
(b) Although timing has been delayed, we currently plan to seek license renewal for Clinton and have received a Timely Renewal Exemption from the NRC that allows for the license renewal application to be filed in the first quarter of 2024.

The operating license renewal process takes approximately four to five years from the commencement of the process, which includes approximately two years for us to develop the application and approximately two additional years for the NRC to review the application. Depreciation provisions are based on the estimated useful lives of the stations, which correspond with the term of the NRC operating licenses denoted in the table above as of December 31, 2021. From August 27, 2020 through September 15, 2021, Byron and Dresden depreciation provisions were accelerated to reflect the previously announced shutdown dates of September 2021 and November 2021, respectively. On September 15, 2021, we updated the estimated useful lives for both facilities to reflect the end of the current NRC operating license for each unit consistent with the table above. See Note 3 — Regulatory Matters and Note 7 — Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information on Byron and Dresden and the Illinois CMC program.

The TMI nuclear station located in Middletown, Pennsylvania, permanently ceased generation operations on September 20, 2019. The Oyster Creek nuclear station located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018, was sold to Holtec International (Holtec) on July 1, 2019. See Note 2 — Mergers, Acquisitions, and Dispositions and Note 7 — Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information on the disposition of Oyster Creek and the retirement of TMI.

Natural Gas, Oil and Renewable Facilities (including Hydroelectric)

We operate approximately 12 gigawatts of natural gas, oil, hydroelectric, wind, and solar generation assets, which provide a mix of baseload, intermediate, and peak power generation. We wholly own all our natural gas, oil and renewable generating stations, except for: (1) Wyman; (2) certain wind project entities; and (3) CRP, which is owned 49% by another owner. We operate all of these facilities, except for Wyman, which is operated by the principal owner, NextEra Energy Resources LLC, a subsidiary of NextEra Energy, Inc. See ITEM 2. PROPERTIES for additional information regarding these generating facilities and Note 21 — Variable Interest Entities of the Notes to Consolidated Financial Statements for additional information regarding CRP, which is a VIE.

In 2021, 2020, and 2019, electric supply (in GWh) generated from our owned natural gas, oil, and renewable generating facilities was 10%, 9%, and 11%, respectively, of our total electric supply. Much of this output was dispatched to support our wholesale and retail power marketing activities. Our natural gas, oil and renewable fleet has similarly demonstrated a track record of strong performance with a power dispatch match[a] of 72.4%, 98.4%, and 97.9% and renewables energy capture[b] of 95.7%, 93.4%, and 96.3% in 2021, 2020, and 2019, respectively. Our power dispatch match performance in 2021 was significantly impacted by the February 2021 extreme weather event in Texas, refer to Note 3 — Regulatory Matters for additional information.

Natural gas, oil, wind and solar generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid, which include our Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). Muddy Run's license expires on December 1, 2055 and Conowingo's on February 28, 2071. The stations are currently being depreciated over their estimated useful lives, which correspond with the available license terms. See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information on Conowingo.

On March 31, 2021 and June 30, 2021, we completed the sale of a significant portion of our solar business and our interest in the Albany Green Energy biomass facility, respectively. Note 2 — Mergers, Acquisitions, and Dispositions for additional information on these dispositions.

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(a) Dispatch Match is used to measure the responsiveness of a unit to the market, expressed as the actual energy relative to the total desired energy. Desired energy is measured by revenues less purchased power and fuel costs when unit is dispatched by us or the RTO.

(b) Energy capture is an indicator of how efficiently the installed assets capture the natural energy available from the wind and the sun. Energy capture represents an energy-based fraction, the numerator of which is the energy produced by the sum of the wind turbines/solar panels in the year, and the denominator of which is the total expected energy to be produced during the year. Energy capture for the combined wind and solar fleet is weighted by the relative site projected pre-tax variable revenue, with deductions made for certain events that are non-controllable, such as force majeure events and transmission curtailments.

Contracted Generation

In addition to energy produced by owned generation assets, we source electricity from plants we do not own under long-term contracts. The following tables summarize our long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2021:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	7	2022 - 2032	176
Midwest	3	2026 - 2032	351
New York	4	2022	26
ERCOT	5	2022 - 2035	864
Other Power Regions	12	2022 - 2033	2,685
Total	31		4,102

	2022	2023	2024	2025	2026	Thereafter	Total
Capacity Expiring (MW)	1,084	114	101	490	398	1,915	4,102

Customer-Facing Business

We are one of the nation’s largest energy suppliers, through our integrated business operations we sell electricity, natural gas, and other energy related products and solutions to various types of customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets across multiple geographic regions. We serve approximately 2 million total customers, including approximately 217,000 commercial, industrial, and public sector customers, including three-fourths of Fortune 100 companies, and about 1.6 million unique residential customers. We also have a non-commodity element of our customer facing business, providing sustainability, efficiency and technology solutions to offer a comprehensive suite of energy solutions to meet customers’ growing and evolving needs.

We are a leader in electric power supply, serving 205 TWhs in 2021 through sales to retail customers and wholesale load auctions to a diverse geographic customer base. The following table illustrates these volumes across our five reportable segments:

2021 Electric Power Supply (TWhs) Served Across Regions(a)

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(a) Includes retail load and wholesale load auction volumes only. Electric generation in excess of our total retail and wholesale load would be marketed to the respective ISO in which our facility is located. Other includes New England, South & West.

We are active in all domestic wholesale power and gas markets that span the entire lower 48 states and have complementary retail activity across many of those states. We largely obtain physical power supply from our owned and contracted generation in multiple geographic regions. The commodity risks associated with the output from owned and contracted generation are managed using various commodity transactions including sales to customers and our ratable hedging program. See further discussion of the ratable hedging program in the Price and Supply Risk Management section below. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both our wholesale and retail customers.

Wholesale Market

Our wholesale channel-to-market involves the sale of electricity among electric utilities and electricity marketers before it is eventually sold to end-use consumers. In 2021, we served approximately 65 TWhs of power load across competitive utility load procurements and bilateral sales to municipalities, co-ops, banks, and other wholesale entities. Complementary to our national portfolio, we have several decades of relationships with wholesale counterparties across all domestic power markets as a means of both monetizing our own generation, as well as sourcing contracted generation to meet customer and portfolio needs. With the increased trend toward customer demand for sustainability, this ability to source contracted generation has provided a capital-light way for us to provide customers with the renewable products they are demanding to support a cleaner energy ecosystem. This creates durable customer relationships and repeatable business through the ability to respond to customer and marketplace trends. Similarly, this contracting acumen provides the ability to supplement our native generation with other non-renewable assets to meet changing portfolio needs in a financially efficient manner. In our wholesale gas business we participate across all parts of the gas value chain, including trading, transport and storage and physical supply.

Retail Market

Retail competition in states across the U.S. range from full competition of generation suppliers for all retail customers (commercial, industrial and residential) to partial retail competition available up to a capped amount for industrial customers only. We are a leader in retail markets, serving approximately 140 TWhs of electric power load and 800 Bcf of gas in 2021, primarily to commercial and industrial ("C&I") customers across multiple geographic regions in the U.S.

Constellation Retail has a Diverse Geographic Footprint

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Strong customer relationships are a key part of our customer-facing business strategy, as demonstrated by our high retention rates. Retail customer retention rates have been strong over the last five years across C&I power customer groups, with average contract terms of approximately 25 months and customer duration of more than six years, with many customers well beyond these metrics. Specifically, we enjoyed a 80% C&I power customer renewal rate and a 89% C&I gas customer retention rate in 2021, consistent with the previous four years, owing to both our competitive pricing as well as our strong customer relationships. Our consistently high renewal rates are driven by our ability to provide customized solutions and deliver focused attention to our customers' needs, resulting in industry-leading customer satisfaction. We are also successful at acquiring new customers by offering diverse innovative services and products that meet their needs. In addition to our high customer renewal rates, we have experienced consistent high new win rates for C&I power as well, acquiring nearly one out of every three new customers who have chosen to shop with us over the past three years.

High customer satisfaction levels, market expertise, stability and scale drive growth and result in historically proven business consistency and margins. While providing customers with the best possible price is a key focus, we leverage our broad suite of electric and gas product structures, oftentimes customized, to provide customers with the commodity solution and information that best fits their needs. It is this attention to the customer that creates the durable, repeatable value highlighted in these statistics.

Consumer purchasing strategies have trended from direct supply relationships to third-party relationships with a growing number of customers looking to third-party consultants and brokers to find suppliers like us to reduce costs and evaluate the increasing number of options available for expanding energy solutions beyond the commodity. In response, we have expanded our third-party capabilities, created scale through a comprehensive support structure, and enhanced digital applications providing tools, tracking and measurement as well as the ability to extend the reach of our sustainability services and products to drive additional market share. While this trend of customers using third-parties to find suppliers has slowed in recent years, we have remained the market leader in direct sales with over 45% of the commercial and industrial market share of direct customer business driven by our highly experienced and long tenor direct sales team.

Energy Solutions

As one of the largest customer-facing platforms in the U.S., we benefit from significant economies of scale, which allow us to provide our customers with competitively priced energy and to structure highly tailored solutions targeted to a customer's unique power needs and clean energy goals. We partner with our customers to provide options along the sustainability continuum, including, renewable, efficiency and technology applications to meet their carbon-free energy goals. Our energy efficiency products provide the ability to optimize performance and maximize efficiency across customer facilities and operations through contract structures that include implementation of energy efficiency upgrades with no upfront capital requirements. Additionally, these services provide scalable solutions to meet sustainability goals through investment across the life of the facility or operations and allow for budget certainty. The ongoing ability to optimize energy consumption for customers allows us to support customer demands with the right combination of technology and efficiency program options.

For example, our CORe product serves C&I customers' sustainability needs by matching contracted, third-party renewable generation with customer desire to add additional carbon free generation to the grid (additionality) and geographic preference. In addition to larger-scale CORe offerings, we offer a range of sustainability attribute solutions to customers (RECs, EFECs, RINs, RNG, carbon offsets, etc.) to support their energy needs during the transition to a cleaner energy ecosystem.

Pear.ai is our smart utility expense management platform that helps customers proactively manage utility costs, understand trends, and develop strategies to optimize spend and drive sustainability objectives. Pear.ai provides new avenues for incremental growth by coupling the opportunities for customer usage optimization with accompanying products and solutions that we can provide to customers. Services like Pear.ai allow us to grow our customer base in previously inaccessible regulated markets through the offering of non-commodity energy products.

Our Constellation Technology Ventures' commercialization team invests in and collaborates with portfolio companies to deploy products and technologies across our broad customer base to drive value for both us and portfolio companies. Portfolio company solutions have included EV and charging infrastructure, sustainability monitoring and reporting tools, distributed energy resources and financing solutions, a web-based energy marketplace, and more.

Price and Supply Risk Management

We use a combination of wholesale and retail customer load sales, as well as non-derivative and derivative contracts, using both over-the-counter and exchange-traded instruments, including options, swaps, and forward and futures contracts, all with credit-approved counterparties, to hedge the price risk of the generation portfolio. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis, providing cash flow stability for our investors while still allowing commercial opportunities to generate value for the enterprise. We may also enter transactions that are outside of this ratable hedging program. We are exposed to commodity price risk in 2022 and beyond for portions of our electricity portfolio that are unhedged. As of December 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 92%-95% and 73%-76% for 2022 and 2023, respectively. Similarly, the scale and scope of the portfolio provides risk-mitigating technology, product, and geographical diversification. We will continue to be proactive in using hedging strategies to mitigate commodity price volatility.

The percentage of expected generation hedged is the number of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generation based on a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all wholesale and retail load sales, as well as hedging products, which include economic hedges and certain non-derivative contracts. A portion of our hedging strategy may be implemented using fuel products based on assumed correlations between power and fuel prices. Our risk management group monitors the financial risks of the wholesale and retail power marketing activities. We also use financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of our efforts. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride, and the fabrication of fuel assemblies. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. We have inventory in various forms and do not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment, or fabrication services to meet the nuclear fuel requirements of our nuclear units. We size our inventory holdings and forward contractual requirements to protect against supply disruptions and near-term price volatility, while mitigating concentration of risk with our suppliers and allowing for capital flexibility.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Seasonality

Our operations are affected by weather, which affects demand for electricity and natural gas, as well as operating conditions. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months is referred to as “favorable weather conditions” because those weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. As a result, our operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or extreme winter weather make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities owned, the retail load served and the terms of contracts to purchase or sell electricity. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Insurance

We are subject to liability, property damage, and other risks associated with major incidents at our generating stations. We have reduced our financial exposure to these risks through insurance, both property damage and liability, and other industry risk-sharing provisions. We also maintain business interruption insurance for our renewable projects, but not for our other generating stations unless required by contract or financing agreements. We are self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for our insured losses.

For additional information regarding property insurance, see ITEM 2. PROPERTIES, Note 17 — Debt and Credit Agreements for additional information on financing agreements, and Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements for insurance specific to our nuclear facilities.

Regulation

We are a public utility as defined under the Federal Power Act and are subject to FERC's exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity, and ancillary services to ensure that such sales are just and reasonable. FERC's jurisdiction over ratemaking includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities.

RTOs and ISOs are FERC regulated entities that exist in several regions to provide transmission service across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE, and SPP as RTOs and CAISO and NYISO as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX, and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC.

We are subject to the jurisdiction of the NRC with respect to the operation of our nuclear generating facilities, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security, and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results and communicates its assessment on a semi-annual basis. All nuclear generating stations operated by us are categorized by the NRC in the Licensee Response Column, which is the highest of five performance bands. The NRC may modify, suspend, or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures and/or operating costs for our nuclear generating facilities. NRC regulations also require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. The ultimate decommissioning obligation is expected to be funded by the NDT funds. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Liquidity and Capital Resources; Critical Accounting Policies and Estimates, Nuclear Decommissioning Asset Retirement Obligations; and Note 3 — Regulatory Matters, Note 10 — Asset Retirement Obligations, and Note 18 — Fair Value of Financial Assets and Liabilities of the Notes to Consolidated Financial statements for additional information regarding our NDT funds and decommissioning obligations.

Our operations are also subject to the jurisdiction of various other Federal, state, regional, and local agencies, and Federal and state environmental protection agencies. Additionally, we are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Constellation's Strategy and Outlook

Strategy

We believe shareholder value is built on a foundation of operational excellence and the pairing of our majority carbon-free energy fleet with our customer facing platform. We are committed to maintaining investment grade credit ratings. We are focused on optimizing cash returns through a disciplined approach to safe and efficient operations and cost management, underpinned by stable and durable margins from our customer-facing businesses and coupled with visible payments to our generation plants for the clean energy attributes. We may pursue future growth opportunities that provide additional value building on our core businesses, or expanding our competitive advantages. We are committed to maintaining a strong balance sheet, to returning value to our shareholders, and to investing in clean energy solutions.

As environmental sustainability continues to build momentum for businesses across the country, the demand for carbon-free and sustainability products increases. We are committed to a carbon-free energy future, and we aim to serve as a partner to businesses and the federal, state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis. For two decades, our predecessor company was a strong advocate for policies that would address the climate crisis. We will continue to be a leading advocate at the federal level and in our states for policies that will reduce GHG emissions and preserve and grow clean energy.

Building upon Exelon's long-standing commitment to reducing our GHG emissions, we are committed to the following:

1. Achieving a generation portfolio mix with 100% of our owned generation carbon-free by 2040, including an interim goal of 95% carbon-free by 2030, subject to policy support and technology advancements
2. A 100% reduction of our operations-driven emissions by 2040, including an interim goal to reduce carbon emissions by 65% from 2020 levels by 2030 and reduce methane emissions 30% from 2020 by 2030, and
3. Providing 100% of C&I customers with specific information about their GHG impact.

Our business strategy is to maximize value for all our stakeholders, coupled with ESG principles that are integrated with and core to our strategy, through a particular emphasis on:

Carbon-Free Energy Advocacy. We will continue to work with policymakers to find solutions that drive decarbonization and provide value to customers.

Carbon-Free Energy & Climate Mitigation. We will continue to prioritize safety in operating our reliable, best in class, carbon-free, generation assets and growing the supply of clean power, fuels, and energy carriers including hydrogen that will be essential to fighting the climate crisis. We will mitigate the impacts of climate change on our business through adaptation and building resiliency in our supply chain through partnerships with our key suppliers to build a sustainable supply chain that delivers energy and quality products and services and responsibly manages waste. We will also partner with our key energy suppliers on their GHG emissions and climate adaptation strategies.

Clean Customer Transformation. Customers, including businesses and cities, are transforming to become more sustainable from energy supply to management. From products that supply clean power when they need it 24 hours a day to transformative solutions to integrate clean fuels, we will continue to innovate and develop new products to meet our customers' needs.

Technology and Commercialization. We will partner with our customers, suppliers, universities, governments, national labs, and startups to support technology advancement through development, partnerships and commercialization pathways. We commit to help enable future technologies and business models needed to drive the clean energy economy to improve the health and welfare of communities through venture investing and R&D. We will target 25% of these investments to minority and women led businesses and will require investment recipients to disclose how they engage in equitable employment and contracting practices, using performance as a factor when considering investments.

Equity and Community Empowerment. We are committed to building a future in which all of our customers, employees, business partners, and communities benefit equitably from social, environmental and economic progress.

Diversity, Equity and Inclusion. Our commitment is an advantage in the fight against climate change, including a commitment to attract, retain, and develop a diverse, equitable workforce, promote an inclusive culture and extend diversity and inclusiveness throughout our value chain.

Governance and Ethics. We will build upon a strong compliance and risk management foundation from our predecessor company and recognize the critical role this serves in maximizing operational results. We will continue to manage cash flow volatility through prudent risk management strategies across our business.

We are committed to maintaining sufficient financial liquidity and an appropriate capital structure to support safe, secure and reliable operations, even in volatile market conditions. We believe our investment grade credit rating is a competitive advantage and we intend to maintain our credit position and best-in-class balance sheet. In line with that commitment, available cash flow will first be used to comfortably meet investment grade credit targets, with incremental capital allocated towards shareholder return and disciplined growth. We continually evaluate growth opportunities aligned with our businesses, assets and markets leveraging our expertise in those areas and offering sustainable returns. We may pursue growth opportunities that optimize our core business or expand upon our strengths, including, but not limited to the following:

- Opportunistic carbon-free energy acquisitions, particularly nuclear plants with supportive policy
- Create new value from the existing fleet through repowering, co-location and other opportunities
- Grow sustainability products and services for our customers focused on clean energy, efficiency, storage and electrification; help our C&I customers develop and meet sustainability targets
- Produce clean hydrogen using our carbon-free fleet
- Engagement with the technology and innovation ecosystem through continued partnerships with national labs, universities, startups, and research institutions
- Explore advanced nuclear technology for investment and participation via advisory services to maintain our leadership position as stewards of a carbon-free energy future

We will employ a disciplined approach to acquisitions that grow future cash flow and support strategic initiatives. We will also continue to evaluate asset and business divestitures to rationalize the portfolio and optimize cash proceeds.

Various market, financial, regulatory, legislative and operational factors could affect our success in pursuing these strategies. We continue to assess infrastructure, operational, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information.

Outlook

The U.S. energy sector is experiencing unprecedented changes that we believe will increase the demand for reliable, clean power generation and benefit our business. We believe our generation fleet, including our nuclear assets, is well-positioned to deliver reliable, clean power and benefit from growing demand for carbon-free electricity. Key drivers of increased demand for clean energy include:

- Governmental and corporate policies designed to accelerate the decarbonization of the economy,
- Policy support for nuclear energy sources that also enable energy security, reliability and diversification,
- Rapid electrification of the U.S. economy; and
- Evolving customer preferences favoring clean energy, choice and digitization

Policy Support for Decarbonization and Emerging Carbon-Free Technologies. Driven by societal concerns about climate change, governments, corporations, and investors are increasingly advocating for the reduction of GHG emissions across all sectors of the economy, with reduction of GHG emissions by the energy sector being a key focus. Governments at the international, national and state levels have established or are currently contemplating increasingly stringent policies that require the reduction of GHG emissions over time. Corporations have also adopted targets to reduce the carbon emissions in their business operations, spurred in part by demand from investors and customers for sustainable, environment-friendly business practices. Emerging technologies like storage and hydrogen are also helping to advance decarbonization. We are committed to a clean energy future and we believe our business is well-positioned to benefit from growing policy support for decarbonization as our generation fleet is essential to helping meet clean energy targets at both the state and federal levels.

Policy Support for Nuclear Energy. As decarbonization accelerates, we expect our generation fleet will play a critical role in meeting baseload power needs. Nuclear energy is currently the largest source of zero emissions electricity in the U.S., accounting for over 50% of the nation's carbon-free power and our nuclear plants are meaningful contributors to the clean energy mix in the states in which they operate. Given the Biden Administration's aggressive goals for reducing emissions within the electric power sector, policymakers have recognized the urgent need to prevent the retirement of nuclear power plants prior to the end of their licensed lives. Several states where our nuclear facilities operate have established policies to support nuclear generation, driven by factors that include recognition by governments and policy makers that existing nuclear generation facilities are essential to meeting policy objectives on reduction of GHG emissions, the desire to support jobs and regional economies, and the need to ensure reliability and security of the electrical grid through resource diversity. A 2018 study by the Massachusetts Institute of Technology, "The Future of Nuclear Energy in a Carbon-Constrained World," found that the costs of achieving transformational decarbonization targets would increase significantly without the contribution of nuclear power. As such, we plan to file applications to extend the licenses of our nuclear fleet to 80 years for our units that receive continued policy support for their long-term operation.

Electrification of the U.S Economy. The push to significantly reduce or eliminate GHG emissions could lead to acceleration of the electrification of the U.S. economy, including electrification of transportation, industrial operations, heating and cooling, and appliances, which could materially increase demand for electricity. We expect widespread electrification could result in U.S. electricity demand to nearly double from what it is today by 2050. Although EV sales in North America are well behind Europe and China, increased policy support from the Biden administration, together with an increasing number of EV offerings hitting the market over the next five years, will drive market share gains in the U.S. market. With over 90% of states offering incentives for setting up EV charging infrastructure, U.S. EV market sales are projected to rise to 6.9 million units by 2025. Electrification of industrial processes, commercial equipment and residential appliances that currently utilize gas and oil as a fuel source will also play a role in increasing the net demand for electricity. According to the International Energy Agency, heat makes up two-thirds of industrial energy demand, and almost one-fifth of global energy consumption, prompting efforts by energy companies and industrial manufacturers to electrify their thermal processes. For companies like us whose core competency is safely generating and serving electricity and related products to its customers, the increasing demand from electrification provides natural growth opportunities.

Evolving Customer Preferences. Consumers are increasingly purpose-driven and knowledgeable of services that drive decarbonization, leading them to value the ability to be connected to and trace the source of their clean energy choices. A third-party study found that 60% of consumers have become more aware of climate change since the start of the COVID-19 pandemic, with more than half of consumers likely to invest and upgrade to energy efficiency programs. Growing awareness of climate change and green energy helps drive customer interest in value-add services and products around their energy usage, such as residential rooftop solar, EV charging, smart, energy-efficient home technologies, and the ability to choose 100 percent clean power 24 hours a day, 365 days a year in competitive retail energy markets. Continuing innovation in the digitization of the broader economy will facilitate greater control and opportunities for customers and businesses to more frequently engage with their energy providers and become more knowledgeable of their energy choices, including the products we provide.

Employees

Engaged Workforce

Our employees are our greatest assets. We strive to create a workplace that is diverse, inclusive, innovative, and safe for our employees. In order to provide the services and products that our customers expect, we must create the best teams and these teams must reflect the diversity of the communities that we serve. Therefore, we strive to attract highly qualified and diverse talent and routinely review our hiring, development and promotion practices to ensure we maintain equitable and bias free processes.

We will continue to undertake extensive and periodic employee engagement surveys to help identify our successes and opportunities for growth. The survey results will be reviewed with senior management and our Board of Directors.

Career Development

We provide our employees with growth opportunities, competitive compensation and benefits, and a variety of education and development programs. We are committed to helping employees advance their skills and careers largely through educational opportunities in technical, safety and business acumen areas, in addition to development through individual discussions and mentorship programs, as well as continuous feedback and evaluations. We understand that continued education leads to a more engaged, skilled and productive workforce and we support our employees in their educational endeavors in order to attract and retain people who are committed to personal and professional development by offering tuition reimbursement for approved higher education, certification or licensing courses.

Well-Being and Benefits

Our employees are encouraged to thrive outside the workplace as well. We provide a full suite of wellness benefits targeted at supporting work-life balance, physical, mental and financial health, and industry-leading paid leave policies. Considering the COVID-19 pandemic, our employees also received additional benefits including 100% coverage of all in-network medical expenses associated with COVID-19 testing and treatment through June 2021, paid time off to receive a COVID-19 vaccine, and extended back-up child and elder care benefits through September 2020.

Community

We are also committed to helping improve the quality of life for people in the communities where we live, work and serve. We provide opportunities for company-sponsored volunteerism. Even in pandemic conditions, our employees donated nearly $4 million to non-profit organizations and provided just over 34,000 volunteer hours in 2021.

Next Generation of Talent

We are also committed to exposing people within our communities to career opportunities in the energy industry. Through internships, university and veteran recruiting, STEM programs, and partnerships with organizations such as the Society of Women Engineers and the National Society of Black Engineers, we are committed to providing professional development and opportunities for the next generation of our workforce. Major focus areas include:

- Creating STEM and vocational education and awareness
- Reducing or removing educational barriers and obstacles faced by young people and underrepresented and underserved members of the community and
- Deepening current and executing new approaches and partnerships with employers, nonprofits, and community groups to expand training and job opportunities for work-ready adults and youth

Diversity Metrics

The following table shows diversity metrics for all employees and management as of December 31, 2021:

Metric	All Employees	Management[d]
Female[a][b]	2,389	320
People of Color[b]	2,030	229
Aged <30	1,293	49
Aged 30-50	6,399	1,187
Aged >50	4,004	758
Within 10 years of retirement eligibility	5,242	1,034
Total Employees[c]	11,696	1,994

(a) We are devoted to creating an environment that allows women to stay in the workforce, grow with the company, and move up the ranks, all with parity of pay. We employed an independent third-party vendor to run regression analysis on all management positions each year and the analysis has consistently shown that the we have no systemic pay equity issues.
(b) This is based on self-disclosed information.
(c) Total employees represents the sum of the aged categories.
(d) Management is defined as executive/senior level officials and managers as well as all employees who have direct reports and supervisory responsibilities.

Turnover Rates

As turnover is inherent, management succession planning is performed and tracked for all executives and critical key manager positions. Management frequently reviews succession planning to ensure we are prepared when positions become available.

The table below shows the average turnover rate for all employees for the last three years of 2019 to 2021:

	All
Retirement Age	5.14 %
Voluntary	4.31 %
Non-Voluntary	1.34 %

Collective Bargaining Agreements

Approximately 28% of employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2021:

Total Employees Covered by CBAs	Number of CBAs	CBAs New and Renewed in 2021[a]	Total Employees Under CBAs New and Renewed in 2021
3,274	22	4	1,592

(a) Does not include CBAs that were extended in 2021 while negotiations are ongoing for renewal.

Environmental Matters and Regulation

We are subject to comprehensive and complex environmental legislation and regulation at the federal, state, and local levels, including requirements relating to climate change, air and water quality, solid and hazardous waste, and impacts on species and habitats.

Our Board of Directors is responsible for overseeing the management of environmental matters. We have a management team to address environmental compliance and strategy, including the CEO and other senior management. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. Our Board of

Directors has delegated to its Nuclear Oversight Committee and the Corporate Governance Committee the authority to oversee our compliance with health, environmental, and safety laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including our internal climate change and sustainability policies and programs, as discussed in further detail below.

Climate Change

Driven by societal concerns about climate change, governments, corporations, and investors are increasingly advocating for the reduction of GHG emissions across all sectors of the economy, with reduction of GHG emissions by the energy sector being a key focus. Governments at the international, national and state levels have established or are currently contemplating increasingly stringent policies that require the reduction of GHG emissions over time. Corporations have also adopted targets to reduce the carbon emissions in their business operations, spurred in part by demand from investors and customers for sustainable, environment-friendly business practices. Emerging technologies like storage and hydrogen are also helping to advance decarbonization.

We believe our business is well-positioned to benefit from growing policy support for decarbonization. However, as detailed below, we also face climate change mitigation and transition risks as well as adaptation risks. Mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG reduction goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions. Adaptation risk refers to risks to our facilities or operations that may result from changes in the physical climate, such as changes to temperatures, weather patterns and sea level rise. See ITEM 1A. RISK FACTORS for additional information.

Climate Change Mitigation and Transition

We support comprehensive federal climate legislation that addresses the climate crisis and would ensure the country meets the targets set by the Paris Climate Accord. In the absence of comprehensive federal legislation, we support EPA moving forward with meaningful regulation of GHG emissions under the Clean Air Act. We currently are subject to, and may become subject to additional, federal and/or state legislation and/or regulations addressing GHG emissions.

We are deliberately positioned as a low-carbon generation company. We have minimized GHG emitting assets in our portfolio and maximized carbon-free electric production such that our generation emissions intensity is already 80% less than 2005 levels in support of achieving economy-wide GHG emissions reduction goals. Our Scope 1 and 2 GHG emissions in 2020 were 8.2 million metric tons carbon dioxide equivalent, of which 7.8 million metric tons were from our natural gas and oil fueled generation fleet, significantly less than our peers with similar volume of power generation.

We produce electricity predominantly from low and carbon-free generating facilities (such as nuclear, hydroelectric, natural gas, wind, and solar PV) and neither own nor operate any coal-fueled generating assets. Our natural gas and oil generating plants produce GHG emissions, most notably $CO2$. In addition, we sell natural gas at retail; and consumers' use of such natural gas produces GHG emissions. However, our owned-asset emission intensity, or rate of carbon dioxide equivalent ($CO2e$) emitted per unit of electricity generated, is among the lowest in the industry. In 2021, we achieved a 94.5% percent capacity factor across our nuclear fleet and our ownership of 21 gigawatts of carbon-free generation capacity at 23 nuclear units produced 175 TWhs of electricity in 2021 — approximately 10% of U.S. carbon-free electric supply.

The electric sector plays a key role in lowering GHG emissions across the rest of the economy. Electrification of other sectors such as transportation and buildings coupled with simultaneous decarbonization of electric generation is a key lever for emissions reductions. To support this transition, we are advocating for public policy supportive of vehicle electrification, investing in enabling infrastructure and technology, and supporting customer education and adoption. We also continue to explore other decarbonization opportunities, supporting pilots of emerging energy technologies and development of clean fuels.

International Climate Change Agreements. At the international level, the United States is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. On November 4, 2020, the United States formally withdrew from the Paris Agreement, retracting its commitment to reduce domestic GHG emissions by 26%-28% by 2025 compared with 2005 levels. However, on January 20, 2021, President Biden accepted the Paris Agreement, which resulted in the United States' formal re-entry on February 19, 2021. The United States has now set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels by 2030. The 2021 UNFCCC Conference of the Parties (COP26) and resulting Glasgow Climate Pact indicated important global support for the Paris Agreement and continued progress toward decarbonization.

Federal Climate Change Legislation and Regulation. Combating climate change is one of the top legislative agenda items of the Biden administration, with the President proposing a 100% clean energy economy with net zero GHG emissions by 2050 and to reduce U.S. emissions by 50% or more from 2005 levels by 2030. While consideration of the Build Back Better Act has stalled in Congress, Senator Joe Manchin continues to express an openness to a smaller bill that includes climate-related provisions that include a production tax credit for clean power sources. We support federal tax credits that recognize the value of existing carbon-free nuclear plants and support the development of hydrogen solutions. It is uncertain when, or whether, Congress will consider action on a climate bill, but the Biden Administration and members of Congress have recognized the importance of existing nuclear power plants, which provide half of the nation's emissions-free energy, to meeting U.S. climate goals. A federal tax credit would prevent the continued premature closure of nuclear plants for economic reasons.

Regulation of GHGs from Power Plants under the Clean Air Act. The EPA's 2015 Clean Power Plan (CPP) established regulations addressing carbon dioxide emissions from existing fossil-fired power plants under Clean Air Act Section 111(d). The CPP's carbon pollution limits could be met through changes to the electric generation system, including shifting generation from higher-emitting units to lower- or zero-emitting units, as well as the development of new or expanded zero-emissions generation. In July 2019, the EPA published its final Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines for existing fossil-fired power plants based on heat rate improvement measures that could be achieved within the fence line of individual plants. We, as part of Exelon, together with a coalition of other electric utilities, filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit on September 6, 2019, challenging the Affordable Clean Energy rule as unlawful. This lawsuit was consolidated with separate challenges to the Affordable Clean Energy rule filed by various states, non-governmental organizations, and business coalitions. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit held the Affordable Clean Energy Rule to be unlawful, vacated the rule, and remanded it to the EPA. On October 29, 2021, the Supreme Court granted certiorari to examine the extent of EPA's authority to regulate GHGs from power plants; a decision is expected in 2022. The EPA has indicated it will promulgate new GHG limits for existing power plants.

State Climate Change Legislation and Regulation. Many states in which we operate have state and regional programs to reduce GHG emissions and renewable and other portfolio standards, which impact the power sector and other sectors as well. 25 states and the District of Columbia have 100% clean energy targets, deep GHG reductions, or both, encompassing 54% of U.S residential electricity customers. See discussion below for additional information on renewable and other portfolio standards. As the nation's largest generator of carbon-free electricity, our fleet supports these efforts to produce safe, reliable electricity with minimal GHGs.

Eleven northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia) currently participate in the RGGI, which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO_2 emissions. Non-emitting resources do not have to purchase or hold these allowances. In October 2019, the Governor of Pennsylvania issued an Executive Order directing the PA DEP to begin a rulemaking process to allow Pennsylvania to join the RGGI, with the goal of reducing carbon emissions from the electricity sector. The Environmental Quality Board of the PA DEP approved that rule on July 13, 2021, paving the way for Pennsylvania's participation in RGGI beginning sometime in 2022.

In 2019, New York enacted the Climate Leadership and Community Protection Act, which commits the state to achieving net zero emissions by 2050, with interim emission reduction and renewable energy requirements in 2030 and 2040. New Jersey's Energy Master Plan, released in 2020, provides a comprehensive roadmap for achieving the state's goal of a 100% clean energy economy by 2050 and its Global Warming Response Act's stated GHG emissions reductions of 80% below 2006 levels by 2050. On September 15, 2021, Illinois Public Act 102-0662 was signed into law by the Governor of Illinois. The Clean Energy Law is designed to achieve 100%

carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity.

Our nuclear plants are meaningful contributors to the clean energy mix in the states in which they operate. States may not be able to meet their zero-carbon goals without our nuclear plants, as our plants provide a significant portion of the current carbon-free power. Several states in which our nuclear facilities operate have established policies to support nuclear generation. The supportive policies are driven by several factors, including recognition by governments and policy makers that existing nuclear generation facilities are essential to meeting policy objectives on reduction of GHG emissions, the desire to support jobs and regional economies, and the need to ensure reliability and security of the electrical grid through resource diversity. These state-specific policies (date of enactment) include the following:

- New York Clean Energy Standard (2016) – established a ZEC program that preserves the environmental attributes of our FitzPatrick, Ginna, and NMP nuclear facilities through 2029
- Illinois Zero Emission Standard (2016) - established a ZEC program that preserves the environmental attributes of our Clinton and Quad Cities nuclear facilities through 2027
- New Jersey Clean Energy Legislation (2018) – established a ZEC program that includes preserving the environmental attributes of the Salem nuclear facility, currently through 2025
- Illinois Clean Energy Law (2021) – established a CMC program that preserves the environmental attributes of our Byron, Braidwood, and Dresden nuclear facilities through 2027

See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information on the New Jersey Clean Energy Legislation and the Illinois Clean Energy Law.

Renewable and Clean Energy Standards. Thirty states and the District of Columbia, incorporating most of the states where we operate, have adopted some form of renewable or clean energy procurement requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. Load Serving Entities comply with these various requirements through purchasing qualifying renewables, acquiring sufficient credits (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives.

While we cannot predict the nature of future regulations or how such regulations might impact future financial statements, we have a low emission portfolio, and GHG restrictions would likely benefit our zero- and low-emission generating units relative to other higher-emission fossil fuel-fired generating units.

Corporate Clean Energy Targets. Corporations are facing increasing pressure from their customers and investors to align their businesses with international and national environmental and sustainability objectives, including supporting goals to reduce GHG emissions in their business operations. Leading institutional investors and money managers are increasingly considering sustainability as a key factor in investment decisions and are increasingly advocating for more transparency in disclosure on climate-related matters and pledging to align proxy voting to climate-rated proposals with its fiduciary duty. An increasing number of corporations are also proactively making commitments to reducing their GHG emissions footprint, either through procuring increasing amounts of clean energy or RECs to offset their carbon footprint over time. As the nation's largest producer of carbon-free energy, we support taking bold action to address the climate change crisis and reestablish leadership in both emerging technologies and existing clean infrastructure that together will power the future.

Emerging Carbon-Free Technologies. Emerging carbon-free technologies like storage and hydrogen are also expected to help accelerate the economy's decarbonization. Lower costs, state-directed mandates, a backlog of storage projects in the interconnection queue, and utilities seeking large-scale storage capacity to support higher renewables penetration have created conditions for rapid growth of this technology in the U.S. Clean hydrogen also has the potential to drive decarbonization, particularly as it relates to more challenging sectors like long-haul transportation, steel, chemicals, heating, agriculture, and long-term power storage. Nuclear power can be used to produce clean hydrogen, and our nuclear fleet positions us well to explore this emerging space. Both energy storage and clean hydrogen continue to gain political and business support and are expected to help support net-zero carbon goals.

Climate Change Adaptation

Our facilities and operations are subject to the global impacts of climate change. Long-term shifts in climactic patterns, such as sustained higher temperatures and sea level rise, may present challenges for our facilities and services. We believe our operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS, for additional information.

We conduct seasonal readiness reviews at our power plants to ensure availability of fuel supplies and equipment performance before entering the summer and winter seasons and we consider and review national climate assessments to inform our longer-term planning. Our nuclear fleet is resilient to weather extremes and generates emissions free electricity 24 hours a day even during unexpectedly cold winter events and hot summer events.

Other Environmental Regulation

Air Quality

Mercury and Air Toxics Standards (MATS). In 2011, the EPA signed a final rule, known as MATS, to reduce emissions of hazardous air pollutants from power plants. MATS requires coal-fired power plants to achieve high removal rates of mercury, acid gases, and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. In 2016, in response to a Supreme Court decision requiring the EPA to consider costs in determining whether it was appropriate and necessary to regulate power plant emissions of hazardous air pollutants, the EPA issued a supplemental finding that, after considering costs, it remained appropriate and necessary. On May 22, 2020, the EPA reversed course, publishing a final rule revoking the "appropriate and necessary" finding underpinning MATS. A coal mining company filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit seeking vacatur of MATS based on the EPA's May 22, 2020 finding; on September 11, 2020, the U.S. Court of Appeals for the D.C. Circuit granted a motion by Exelon and two other entities to intervene in that lawsuit to defend MATS, and on September 28, 2020, the U.S. Court of Appeals for the D.C. Circuit issued an Executive Order holding this portion of the MATS litigation in abeyance. On July 21, 2020, Exelon and two other entities filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit challenging the EPA's May 22, 2020 rescission of the appropriate and necessary finding underpinning MATS. This portion of the case is also being held in abeyance in response to the DOJ's motion filed February 12, 2021. On January 20, 2021, President Biden issued an Executive Order directing the EPA to reconsider its May 22, 2020 rescission; on January 31, 2022 EPA signed a proposal to reaffirm that it is "appropriate and necessary" to regulate hazardous air pollutant emissions from coal- and oil-fired power plants under section 112 of the Clean Air Act. As a result, this litigation is likely to be rendered moot, and MATS will likely remain in place in the interim.

Water Quality

Under the federal Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated, and permits must be renewed periodically. Certain of our facilities discharge water into waterways and are therefore, subject to these regulations and operate under NPDES permits.

Clean Water Act Section 316(b) is implemented through the NDPES program and requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. Our power generation facilities with cooling water intake systems are subject to the EPA's Section 316(b) regulations finalized in 2014; the regulation's requirements have been or will be addressed through renewal of these facilities' NPDES permits. Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, we cannot estimate the effect that compliance with the EPA's 2014 rule will have on the operation of our generating facilities and our financial statements. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility's economic viability could be called into question. However, the final rule does not mandate cooling towers and allows state permitting directors to require alternative, less costly technologies and/or operational measures, based on a site-specific assessment of the feasibility, costs, and benefits of available options.

On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

Under Clean Water Act Section 404 and state laws and regulations, we may be required to obtain permits for projects involving dredge or fill activities in Waters of the United States.

Where our facilities are required to secure a federal license or permit for activities that may result in a discharge to covered waters, we may be required to obtain a state water quality certification for those facilities under Clean Water Act section 401.

We are also subject to the jurisdiction of the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage.

Solid and Hazardous Waste and Environmental Remediation

CERCLA provides for response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of hazardous waste at sites, many of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight. Most states have also enacted statutes that contain provisions substantially like CERCLA. Such statutes apply in many states where we currently own or operate, or previously owned or operated facilities, including Delaware, Illinois, Maryland, New Jersey, and Pennsylvania and the District of Columbia. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Our operations have in the past, and may in the future, require substantial expenditures in order to comply with these Federal and state environmental laws. Under these laws, we may be liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease several real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. We are, or could become in the future, parties to proceedings initiated by the EPA, state agencies, and/or other responsible parties under CERCLA and RCRA or similar state laws with respect to several sites or may undertake to investigate and remediate sites for which we may be subject to enforcement actions by an agency or third-party.

As of December 31, 2021, we have established appropriate contingent liabilities for environmental remediation requirements. In addition, we may be required to make significant additional expenditures not presently determinable for other environmental remediation costs. See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Notes to the Consolidated Financial Statements for additional information regarding our environmental matters, remediation efforts, and related impacts to our Consolidated Financial Statements.

Nuclear Waste Storage and Disposal

There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. We currently store all SNF generated by our nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since our SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, we have developed dry cask storage facilities to support operations.

As of December 31, 2021, we had approximately 89,400 SNF assemblies (21,900 tons) stored on site in SNF pools or dry cask storage that includes SNF assemblies at Zion Station, for which we retain ownership and responsibility for the decommissioning of the Zion Independent Spent Fuel Storage Installation. All our nuclear sites currently operating have on-site dry cask storage. TMI's on-site dry cask storage is projected to be in operation in 2022. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at our sites through the end of the current license renewal periods and through decommissioning. For a discussion of matters associated with our contracts with the DOE for the disposal of SNF, see Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site, and none is anticipated to be operational for the next ten years. We ship our Class A LLRW, which represents 93% of LLRW generated at our stations, to disposal facilities in Utah and South Carolina, which have enough storage capacity to store all Class A LLRW for the life of all stations in our nuclear fleet. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Salem), and Connecticut.

We utilize on-site storage capacity at all our stations to store and stage for shipping Class B and Class C LLRW. We have a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from our nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), we will still be required to utilize on-site storage at our stations for Class B and Class C LLRW. We currently have enough storage capacity to store all Class B and Class C LLRW for the life of all stations in our nuclear fleet and continue to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize on-site storage and cost impacts.

ITEM 1A. RISK FACTORS

We operate in a complex market and regulatory environment that involves significant risks, many of which are beyond our direct control. Such risks, which could negatively affect our consolidated financial statements, fall primarily under the categories below:

Risks related to market and financial factors primarily include:

- the price of fuels, in particular the price of natural gas, which affects power prices,
- the generation resources in the markets in which we operate,
- our ability to operate our generating assets, our ability to access capital markets, and the impacts on our results of operations due to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19),
- the impacts of on-going competition, and
- emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy.

Risks related to legislative, regulatory, and legal factors primarily include changes to, and compliance with, the laws and regulations that govern:

- the design of power markets,
- the renewal of permits and operating licenses,
- environmental and climate policy, including ZEC and CMC programs, and
- tax policy.

Risks related to operational factors primarily include:

- changes in the global climate could produce extreme weather events, which could put our facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services,
- the safe, secure and effective operation of our nuclear facilities and the ability to effectively manage the associated decommissioning obligations,
- the ability of energy transmission and distribution companies to maintain the reliability, resiliency and safety of their energy delivery systems, which could affect our ability to deliver energy to our customers and affect our operating costs, and
- physical and cyber security risks for us as an owner-operator of generation facilities and as a participant in commodities trading.

Risks related to our separation from Exelon primarily include:

- challenges to achieving the benefits of separation, including limited business diversification, loss of economies of scale in sourcing goods and services, and the need to replicate certain services provided by Exelon (such as treasury, finance, human resources, investor relations, legal, information technology, security, and supply), which will require additional resources and expense,
- performance by Exelon and us under the transaction agreements, including indemnification responsibilities tied to the allocation of businesses and liabilities, and
- limitations on future capital-raising or strategic transactions during the two-year period following the distribution arising from the need to protect the tax-free treatment of the distribution.

Risks related to our common stock primarily include:

- following the separation, a trading market for our common stock will have only been initiated recently and our stock price may fluctuate significantly and
- certain anti-takeover provisions in our charter and bylaws that could have the effect of delaying or discouraging an acquisition of our company or a change in our management.

Risks Related to Market and Financial Factors

We are exposed to price volatility associated with both the wholesale and retail power markets and the procurement of nuclear and fossil fuels.

We are exposed to commodity price risk for natural gas and the unhedged portion of our electricity generation supply portfolio. Our earnings and cash flows are therefore exposed to variability of spot and forward market prices in the markets in which we operate.

Price of Fuels. The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit.

Cost of Fuel. We depend on nuclear fuel and fossil fuels to operate most of our generating facilities. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions, counterparty default, and geopolitical risk including the current Russia Ukraine conflict and United States sanctions against Russia.

Demand and Supply. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can depress demand. In addition, in some markets, the supply of electricity can exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants such as our nuclear plants. Conversely, new demand sources such as electrification of transportation could increase demand and change demand patterns.

Retail Competition. Our retail operations compete for customers in a competitive environment, which affects the margins we can earn and the volumes we are able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including us) use their retail operations to hedge generation output.

The impact of sustained low market prices or depressed demand and over-supply could be emphasized given our concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect our ability to reduce debt and provide attractive shareholder returns. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect our financial statements primarily through accelerated depreciation and amortization expenses and one-time charges. See Note 7 — Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information.

Market Designs. The wholesale markets vary from region to region with distinct rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect our business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

We are potentially affected by emerging technologies that could over time affect or transform the energy industry.

Advancements in power generation technology, including commercial and residential solar generation installations and commercial micro turbine installations, are improving the cost-effectiveness of customer self-supply of electricity. Improvements in energy storage technology, including batteries and fuel cells, could also better position customers to meet their around-the-clock electricity requirements. Improvements in energy efficiency of lighting, appliances, equipment and building materials will also affect energy consumption by customers. Changes in power generation, storage, and use technologies could have significant effects on customer behaviors and their energy consumption.

These developments could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our generation facilities uneconomic prior to the end of their useful lives. These technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could affect our consolidated financial statements through, among other things, reduced operating revenues, increased operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of our NDT funds and employee benefit plan assets, which then could require significant additional funding.

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within our NDTs and employee benefit plan trusts. We have significant obligations in these areas and hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below our projected return rates. A decline in the market value of the NDT fund investments could increase our funding requirements to decommission our nuclear plants. A decline in the market value of the pension and OPEB plan assets would increase the funding requirements associated with our pension and OPEB plan obligations. Additionally, our pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. See Note 10 — Asset Retirement Obligations and Note 15 — Retirement Benefits of the Notes to Consolidated Financial Statements for additional information.

We could be negatively affected by unstable capital and credit markets and increased volatility in commodity markets.

We rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs. Disruptions in the capital and credit markets in the United States or abroad could negatively affect our ability to access the capital markets or draw on our bank revolving credit facilities. The banks may not be able to meet their funding commitments to us if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, affect our ability to hedge effectively our generation portfolio, require changes to our hedging strategy in order to reduce collateral posting requirements, or require a reduction in discretionary uses of cash. In addition, we have exposure to worldwide financial markets, including Europe, Canada and Asia. Disruptions in these markets could reduce or restrict our ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2021, approximately 26%, 19%, and 17% of our available credit facilities were with European, Canadian and Asian banks, respectively.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be negatively affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts.

If we were to experience a downgrade in our credit ratings to below investment grade or otherwise fail to satisfy the credit standards in our agreements with our counterparties or regulatory financial requirements, we would be required to provide significant amounts of collateral that could affect our liquidity and we could experience higher borrowing costs.

Our business is subject to credit quality standards that could require market participants to post collateral for their obligations upon a decline in ratings. We are also subject to certain financial requirements under NRC regulations as a result of our operation of nuclear power plants that could require us to provide cash collateral or surety bonds if those requirements are not met. One or both events could adversely affect available liquidity and, in the case of a rating downgrade, borrowing and credit support costs.

See ITEM 7.MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Liquidity and Capital Resources – Credit Matters – Market Conditions and Security Ratings for additional information regarding the potential impacts of credit downgrades on our cash flows.

If we fail to meet project-specific financing agreement requirements, we could experience an impairment or loss of the financed project.

We have project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have broad remedies, including rights to foreclose against the project assets and related collateral or to force our subsidiaries in the project-specific financings to enter into bankruptcy proceedings. The impact of bankruptcy could result in the impairment of certain project assets.

Our risk management policies cannot fully eliminate the risk associated with our commodity trading activities.

Our asset-based power position as well as our power marketing, fuel procurement and other commodity trading activities expose us to risks of commodity price movements. We buy and sell energy and other products and enter financial contracts to manage risk and hedge various positions in our power generation portfolio. We are exposed to volatility in financial results for unhedged positions as well as the risk of ineffective hedges. We attempt to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when our policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power, natural gas and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, we cannot predict the impact that our commodity trading activities and risk management decisions could have on our consolidated financial statements.

Financial performance and load requirements could be negatively affected if we are unable to effectively manage our power portfolio.

A significant portion of our power portfolio is used to provide power under procurement contracts with load serving entities and other customers. To the extent portions of the power portfolio are not needed for that purpose, our output is sold in the wholesale power markets. To the extent our power portfolio is not sufficient to meet the requirements of our customers under the related agreements, we must purchase power in the wholesale power markets. Our financial results could be negatively affected if we are unable to meet cost-effectively the load requirements of our customers, manage our power portfolio or effectively address the changes in the wholesale power markets.

The impacts of significant economic downturns could lead to decreased volumes delivered and increased expense for uncollectible customer balances.

The impacts of significant economic downturns on our retail customers, such as less demand for products and services provided by commercial and industrial customers, could result in an increase in the number of uncollectible customer balances and related expense.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information on our credit risk.

Our results were negatively affected by the impacts of COVID-19.

COVID-19 has disrupted economic activity in our markets and negatively affected our results of operations. The estimated impact of COVID-19 to our Net income was approximately $170 million for the year ended December 31, 2020 and was not material for the year ended December 31, 2021. We cannot predict the full extent of the impacts of COVID-19, which will depend on, among other things, the rate, and public perceptions of the effectiveness, of vaccinations and rate of resumption of business activity. In addition, any future widespread pandemic or other local or global health issue could adversely affect customer demand and our ability to operate our generation assets. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview for additional information.

We could be negatively affected by the impacts of weather.

Our operations are affected by weather, which impacts demand for electricity and natural gas, the price of energy commodities, as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, we could require greater resources to meet our contractual commitments. Extreme weather conditions or storms have affected the availability of generation and its transmission, limiting our ability to source or send power to where it is sold, and have also impaired the transportation of natural gas to our generating assets and our ability to supply natural gas to our customers. In addition, drought-like conditions limiting water usage could impact our ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could cause us to seek additional capacity at a time when markets are weak.

Climate change projections suggest increases to summer temperature and humidity trends, as well as more erratic precipitation and storm patterns over the long-term in the areas where we have generation assets. The frequency in which weather conditions emerge outside the current expected climate norms could contribute to the weather-related impacts discussed above.

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. The estimated impact to our Net income arising from these market and weather conditions for the year ended December 31, 2021 was a reduction of approximately $800 million. See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information.

Long-lived assets and other assets could become impaired.

Long-lived assets – principally, generation assets – represent the single largest asset class on our statement of financial position.

We evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment may exist. Factors such as, but not limited to, the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered.

An impairment would require us to reduce the carrying value of the long-lived asset to fair value through a non-cash charge to expense by the amount of the impairment. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Critical Accounting Policies and Estimates, Note 8 — Property, Plant, and Equipment and Note 12 — Asset Impairments of the Notes to Consolidated Financial Statements for additional information on long-lived asset impairments.

We could incur substantial costs in the event of non-performance by third-parties under indemnification agreements, or when we have guaranteed their performance. We are exposed to other credit risks in the power markets that are beyond our control.

We have entered into various agreements with counterparties that require those counterparties to reimburse us and hold us harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, we could be held responsible for the obligations.

We have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets, including several of the Exelon utilities in connection with our absorption of their former generating assets. We could incur substantial costs to fulfill our obligations under these indemnities.

We have issued guarantees for the performance of third parties, which obligate us to perform if the third parties do not perform. In the event of non-performance by those third parties, we could incur substantial costs to fulfill their obligations under these guarantees.

In the bilateral markets, we are exposed to the risk that counterparties that owe us money or are obligated to purchase energy or fuel from us, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, we could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent amounts, if any, were already paid to the counterparties. In the spot markets, we are exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs. We are also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, our retail sales subject us to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer. See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information on the February 2021 extreme cold weather event and Texas-based generating asset outages.

Risks Related to Legislative, Regulatory, and Legal Factors

Federal or state legislative or regulatory actions could negatively affect the scope and functioning of the wholesale markets.

Approximately 65% of our generating resources, which include directly owned assets and capacity obtained through long-term contracts, are in the area encompassed by PJM. Our future results of operations are impacted by (1) FERC's and PJM's level of support for policies that favor the preservation of competitive wholesale power markets and recognize the value of carbon-free electricity and resiliency and for states' energy objectives and policies and (2) the absence of material changes to market structures that would limit or otherwise negatively affect us. Market rules in other regions could affect us in a similar fashion. We could also be affected by state laws, regulations or initiatives to subsidize existing or new generation.

FERC's requirements for market-based rate authority could pose a risk that we may no longer satisfy FERC's tests for market-based rates. A loss of market-based rate authority would mean that we would sell power at cost-based rates.

Our business is highly regulated and could be negatively affected by legislative and/or regulatory actions.

Substantial aspects of our business are subject to comprehensive Federal or state legislation and/or regulation.

Our consolidated financial statements are significantly affected by our sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates and Federal and state regulatory and legislative developments related to emissions, climate change, capacity market mitigation, energy price information, resilience, fuel diversity and RPS. Legislative and regulatory efforts in Illinois, New York and New Jersey to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities through ZEC and CMC programs are or could be subject to legal and regulatory challenges and, if overturned, could result in the early retirement of certain of our nuclear plants. See Note 3 — Regulatory Matters and Note 7 — Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information.

Fundamental changes in regulations or other adverse legislative actions affecting our business would require changes in our business planning models and operations. We cannot predict when or whether legislative and regulatory proposals could become law or what their effect would be.

NRC actions could negatively affect the operations and profitability of our nuclear generating fleet.

Regulatory risk. A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs. Events at nuclear plants owned by others, as well as those owned by us, could cause the NRC to initiate such actions.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF and the timing of that facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse us for these costs.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether a fee may be established or to what extent, in the future for SNF disposal. See Note 19 — Commitments and Contingencies of the Notes to the Consolidated Financial Statements for additional information.

We could be subject to higher costs and/or penalties related to mandatory reliability standards.

We, as a user of the bulk power transmission system, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject us to higher operating costs and/or increased capital expenditures. If we were found in non-compliance with the Federal and state mandatory reliability standards, we could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

We could incur substantial costs to fulfill our obligations related to environmental and other matters.

We are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the way we conduct our operations and make capital expenditures, including how we handle air and water emissions, hazardous and solid waste, and activities affecting surface waters, groundwater, and aquatic and other species. Violations of these requirements could subject us to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, we are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances we generated or released. Also, we are currently involved in several proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future. See ITEM 1. BUSINESS – Environmental Matters and Regulation and Note 19 — Commitments and Contingencies of the Notes to the Consolidated Financial Statements for additional information.

We could be negatively affected by federal and state RPS and/or energy conservation legislation, along with energy conservation by customers.

Changes to current state legislation or the development of Federal legislation that requires the use of clean, renewable and alternate fuel sources could significantly impact us. The impact could include reduced use of some of our generating facilities with effects on our revenues and costs.

Federal and state legislation mandating the implementation of energy conservation programs and new energy consumption technologies could cause declines in customer energy consumption and lead to a decline in our revenues. See ITEM 1. BUSINESS – Environmental Matters and Regulation – Renewable and Clean Energy Standards and "We are potentially affected by emerging technologies that could over time affect or transform the energy industry" above for additional information.

Our financial performance could be negatively affected by risks arising from our ownership and operation of hydroelectric facilities.

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. If FERC does not issue new operating licenses for our hydroelectric facilities in the future or a station cannot be operated through the end of its current operating license, our results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates are currently based on the available license term for each facility. We could also lose revenue and incur increased fuel and purchased power expense to meet our supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, require a substantial increase in capital expenditures, result in increased operating costs or render the project uneconomic. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by us.

We could be negatively affected by challenges to tax positions taken, tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions.

We are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeal issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Note 1 — Significant Accounting Policies and Note 14 — Income Taxes of the Notes to Consolidated Financial Statements for additional information.

Legal proceedings could result in a negative outcome, which we cannot predict.

We are involved in legal proceedings, claims and litigation arising from our business operations. The material ones are summarized in Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial

Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue, or restrict existing business activities.

We could be subject to adverse publicity and reputational risks, which make us vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences.

We could be the subject of public criticism. Adverse publicity of this nature could render public service commissions and other regulatory and legislative authorities less likely to view energy companies in a favorable light, and could cause those companies, including us, to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements.

Risks Related to Operational Factors

We are subject to risks associated with climate change.

Climate adaptation risk refers to risks to our facilities or operations that may result from changes in the physical climate, such as changes to temperatures, weather patterns and sea level rise.

We periodically perform analyses to better understand how climate change could affect our facilities and operations. We primarily operate in the Midwest and East Coast of the United States, areas that have historically been prone to various types of severe weather events, and as such we have well-developed response and recovery programs based on these historical events. However, our physical facilities could be placed at greater risk of damage should changes in the global climate impact temperature and weather patterns, and result in more intense, frequent and extreme weather events, unprecedented levels of precipitation, sea level rise, increased surface water temperatures, and/or other effects. Over time, we may need to make additional investments to protect our facilities from physical climate-related risks.

In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect our operations. Over time, we may need to make additional investments to adapt to changes in operational requirements as a result of climate change.

Climate mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions.

We also periodically perform analyses of potential pathways to reduce power sector and economy-wide GHG emissions to mitigate climate change. To the extent additional GHG reduction regulation or legislation becomes effective at the Federal and/or state levels, we could incur costs to further limit the GHG emissions from our operations or otherwise comply with applicable requirements. To the extent such additional regulation or legislation does not become effective, the potential competitive advantage offered by our low-carbon emission profile may be reduced.

See ITEM 1. BUSINESS – Environmental Matters and Regulation – Climate Change for additional information.

Our financial performance could be negatively affected by matters arising from our ownership and operation of nuclear facilities.

Nuclear capacity factors. Capacity factors for nuclear generating units significantly affect our results of operations. Lower capacity factors could decrease our revenues and increase operating costs by requiring us to produce additional energy from our natural gas and oil fueled facilities or purchase additional energy in the spot or forward markets in order to satisfy our supply obligations to committed third-party sales. These sources generally have higher costs than we incur to produce energy from our nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on our results of operations. When refueling outages last longer than anticipated or we experience unplanned outages, capacity factors decrease, and we face lower margins due to higher energy replacement costs and/or lower energy sales and higher operating and maintenance costs.

Nuclear fuel quality. The quality of nuclear fuel utilized by us could affect the efficiency and costs of our operations. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk. Operations at any of our nuclear generation plants could degrade to the point where we must shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. We could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, we could lose revenue and incur increased purchased power and fuel expense to meet supply commitments.

Further, our nuclear operations produce various types of nuclear waste materials, including SNF. The approval of a national repository for the storage of SNF and the timing of that facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse us for these costs. Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether a fee may be established or to what extent, in the future for SNF disposal.

If we are required to arrange for the safe and permanent disposal of spent fuel beyond current expectations, this could lead to substantial expense or capital expenditures.

For plants operated but not wholly owned by us, we could also incur liability to the co-owners. For nuclear plants not operated and not wholly owned by us, from which we receive a portion of the plants' output, our results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by us could result in increased regulation and reduced public support for nuclear-fueled energy. Closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could adversely affect transmission systems and the sale and delivery of electricity in markets served by us.

Nuclear major incident risk and insurance. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by us or owned by others, could exceed our resources, including insurance coverage. We are a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for our nuclear operations. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by us. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned by us or others, could result in increased regulation and reduced public support for nuclear-fueled energy.

As required by the Price-Anderson Act, we carry the maximum available amount of nuclear liability insurance, $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.5 billion limit for a single incident.

See Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements for additional information of nuclear insurance.

Decommissioning obligation and funding. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility.

We recognize as a liability the present value of the estimated future costs to decommission our nuclear facilities. The estimated liability is based on assumptions in the approach and timing of decommissioning the nuclear facilities, estimation of decommissioning costs and Federal and state regulatory requirements. The costs of such decommissioning may substantially exceed such liability, as facts, circumstances or our estimates may change, including changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in Federal or state regulatory requirements on the decommissioning of such facilities, other changes in our estimates or ability to effectively execute on our planned decommissioning activities.

We make contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to us. While we, through PECO, have recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), we have no recourse to collect additional amounts from utility customers for any of our other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that there was an inability to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if we no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected. Any changes to the PECO regulatory agreements could impact our ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to our financial statements could be material.

Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities for that unit would be discontinued, and the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income, the impact of which could be material. For the year ended December 31, 2021, a pre-tax charge of $193 million was recorded in the Consolidated Statements of Operations and Comprehensive Income for decommissioning-related activities that were not offset for the Byron units due to contractual offset being temporarily suspended.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. If the investments held by our NDT funds are not sufficient to fund the decommissioning of our nuclear units, we could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met

See Note 10 — Asset Retirement Obligations of the Notes to Consolidated Financial Statements for additional information.

We are subject to physical security and cybersecurity risks.

We face physical security and cybersecurity risks. Threat sources continue to seek to exploit potential vulnerabilities in the electric generation and natural gas industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures. These attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks.

A security breach of our physical assets or information systems or those of our competitors, vendors, business partners and interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or result in the theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have not directly experienced a material breach or disruption to our network or information systems or our operations to-date, such attacks continue to increase in sophistication and frequency, and we may be unable to prevent all such attacks in the future.

If a significant breach were to occur, our reputation could be negatively affected, customer confidence in us or others in the industry could be diminished, or we could be subject to legal claims, loss of revenues, increased costs or operations shutdown. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by us or our business operations and could adversely affect our consolidated financial statements.

Our employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry.

Employees and contractors throughout the organization work in, and the general public could be exposed to, potentially dangerous environments near our operations. As a result, employees, contractors and the general public are at some risk for serious injury, including loss of life. These risks include, but are not limited to, nuclear accidents, dam failure, gas explosions, and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact our results of operations, ability to raise capital and future growth.

Our fleet of power plants and the transmission infrastructure to which they are connected could be affected by natural disasters and extreme weather events, which could result in increased costs, including supply chain costs. Natural disasters and other significant events increase our risk that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for our continued operation, particularly the cooling of generating units.

The impact that potential terrorist attacks could have on the industry and on us is uncertain. We face a risk that our operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect our operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly uranium and oil. Furthermore, these catastrophic events could compromise the physical or cybersecurity of our facilities, which could adversely affect our ability to manage our business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also could result in a decline in energy consumption or interruption of fuel or the supply chain. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

We could be significantly affected by the outbreak of a pandemic. We have plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate our generating assets could be adversely affected.

In addition, we maintain a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Our business is capital intensive, and our assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability.

Our business is capital intensive and requires significant investments in electric generating facilities. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond our control, and could require significant expenditures to remedy. Our consolidated financial statements could be negatively affected if we were unable to effectively manage our capital projects or raise the necessary capital. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Liquidity and Capital Resources for additional information regarding our potential future capital expenditures.

Our performance could be negatively affected if we fail to attract and retain an appropriately qualified workforce.

Certain events, such as the separation transaction, an employee strike, loss of employees, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for us. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. We are particularly affected due to the specialized knowledge required of the technical and support employees for generation operations.

We could make acquisitions or investments in new business initiatives and new markets, which may not be successful or achieve the intended financial results.

We could continue to pursue growth in our existing businesses and markets and further diversification across the competitive energy value chain. This could include opportunistic carbon-free energy acquisitions, creating new value from our existing fleet through repowering, co-location and the production of hydrogen, growing sustainability products and services for our customers, and investment opportunities in other emerging technologies and innovation. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered during diligence performed prior to launching an initiative or entering a market. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

Risks Related to Our Separation from Exelon

Following the separation, our financial profile has changed, and we are a smaller, less diversified company than Exelon prior to the separation.

The separation resulted in us being a smaller, less diversified company. As a result, we may be more vulnerable to changing market conditions, which could have a material adverse effect on our business, financial condition and results of operations. In addition, the diversification of our revenues, costs, and cash flows will diminish as a standalone company, such that our results of operations, cash flows, working capital and financing requirements may be subject to increased volatility and our ability to fund capital expenditures and investments, pay dividends and service debt may be diminished.

We may not achieve some or all the expected benefits of the separation, and the separation may materially adversely affect our business.

We may not be able to achieve the full strategic and financial benefits expected to result from the separation, or such benefits may be delayed or not occur at all.

If we fail to achieve some or all the benefits expected to result from the separation, or if such benefits are delayed, it could have a material adverse effect on our competitive position, business, financial condition, results of operations and cash flows.

The terms in our agreements with Exelon could be less beneficial than the terms we may have otherwise received from unaffiliated third parties.

The agreements entered with Exelon in connection with the separation, including the separation agreement, a tax matters agreement, an employee matters agreement, and a transition services agreement, were prepared in the context of the separation while we were still a wholly owned subsidiary of Exelon. Accordingly, during the period in which the terms of those agreements were prepared, we did not have an independent board of directors or a management team that was independent of Exelon. As a result, the terms of those agreements may not reflect terms that would have resulted from negotiations between unaffiliated third parties.

Exelon may fail to perform under various transaction agreements that were executed as part of the separation, which could cause us to incur expenses or losses we would not otherwise incur.

In connection with the separation and prior to the distribution, we and Exelon entered into the separation agreement and entered into various other agreements, including a tax matters agreement, an employee matters agreement, and a transition services agreement. The separation agreement, the tax matters agreement and the employee matters agreement determined the allocation of assets and liabilities between the companies following the separation for those respective areas and include any necessary indemnifications related to liabilities and obligations. We will rely on Exelon to satisfy its performance and payment obligations under these agreements. If Exelon is unable or unwilling to satisfy its obligations under these agreements, including its indemnification obligations, we could incur operational difficulties and/or losses.

In connection with the separation into two public companies, we and Exelon indemnified each other for certain liabilities. If we are required to pay under these indemnities to Exelon, our

financial results could be negatively impacted. The Exelon indemnities may not be sufficient to hold us harmless from the full amount of liabilities for which Exelon will be allocated responsibility, and Exelon may not be able to satisfy its indemnification obligations in the future.

Pursuant to the separation agreement and certain other agreements between Exelon and us, each party will agree to indemnify the other for certain liabilities, in each case for uncapped amounts. Indemnities that we may be required to provide Exelon are not subject to any cap, may be significant and could negatively impact our business. Third parties could also seek to hold us responsible for any of the liabilities that Exelon has agreed to retain. Any amounts we are required to pay pursuant to these indemnification obligations and other liabilities could require us to divert cash that would otherwise have been used in furtherance of our operating business. Further, the indemnities from Exelon for our benefit may not be sufficient to protect us against the full amount of such liabilities, and Exelon may not be able to fully satisfy its indemnification obligations.

Moreover, even if we ultimately succeed in recovering from Exelon any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves. Each of these risks could negatively affect our business, results of operations and financial condition.

We may fail to have necessary systems and services in place when certain of the transaction agreements expire.

If we do not have in place our own systems and services, or if we do not have agreements with other providers of these services once certain separation transaction agreements expire, we may not be able to operate our business effectively, and our profitability may decline. We are in the process of creating our own, or engaging third parties to provide, systems and services to replace many of the systems and services that Exelon currently provides to us. We may incur temporary interruptions in business operations if we cannot transition effectively from Exelon’s existing operating systems, databases and programming languages that support these functions to our own systems. Our failure to implement the new systems and transition our data successfully and cost-effectively could disrupt our business operations and have a material adverse effect on our profitability. In addition, our costs for the operation of these systems may be higher than the amounts reflected in our historical financial statements.

We may not be able to engage in desirable strategic transactions or capital-raising following the separation.

Under current U.S. federal income tax law, a spin-off that otherwise qualifies for tax-free treatment can be rendered taxable to the parent corporation and its shareholders as a result of certain post-spin-off transactions, including certain acquisitions of shares or assets of the spun-off corporation. To preserve the tax-free treatment of the distribution, and in addition to potential tax indemnity obligations, we agreed to certain limitations or prohibitions in the tax matters agreement that may prohibit us, for the two-year period following the distribution and except in specific circumstances, from, among other things:

- entering into any transaction pursuant to which all or a portion of the shares of our stock, or substantially all of our assets, would be acquired, whether by merger or otherwise;
- issuing equity securities beyond certain thresholds;
- repurchasing shares of our stock other than in certain open-market transactions.

The tax matters agreement prohibits us from taking or failing to take any other action that would prevent the distribution and certain related transactions from qualifying as a transaction that is generally tax-free for U.S. federal income tax purposes under Sections 355 and 368(a)(1)(D) of the IRC. These restrictions may limit our ability to pursue certain equity issuances, strategic transactions, repurchases or other transactions that we may believe to be in the best interests of our shareholders or that might increase the value of our business.

Risks Related to Our Common Stock

A trading market for our common stock was only recently initiated following the separation and our stock price may fluctuate significantly.

An active trading market for our common stock was only recently initiated following the separation, which may affect your ability to sell your shares and could lead to our share price being depressed or more volatile. For many reasons, including the risks identified in this "Risk Factors" section, the market price of our common stock following the separation may be more volatile than the market price of Exelon's common stock before the separation. These factors may result in short-term or long-term negative pressure on the value of our common stock.

We cannot predict the prices at which our common stock may trade. The market price of our common stock may fluctuate significantly, depending on many factors including the following:

- our announcements or our competitors' announcements regarding new products or services, enhancements, significant contracts, acquisitions or strategic investments;
- fluctuations in our quarterly or annual financial results or the quarterly or annual financial results of companies perceived to be similar to us;
- changes in earnings estimates or recommendations by securities analysts or our ability to meet those estimates;
- the operating and stock price performance of other comparable companies;
- investors' general perception of us and our industry;
- changes to the regulatory and legal environment under which we operate;
- changes in general economic and market conditions; and
- changes in industry conditions.

In addition, if the market for stocks in our industry, or the stock market in general, experiences a loss of investor confidence, the trading price of our common stock could decline for reasons unrelated to our business, financial condition or results of operations. If any of the foregoing occurs, it could cause our stock price to fall and may expose us to lawsuits that, even if successfully defended, could be costly to defend and a distraction to management.

Anti-takeover provisions could enable us to resist a takeover attempt by a third-party.

Our amended and restated articles of incorporation and amended and restated bylaws contain, and Pennsylvania law contains, provisions that are intended to deter coercive takeover practices and inadequate takeover bids by making such practices or bids unacceptably expensive to the bidder and to encourage prospective acquirers to negotiate with our board of directors rather than to attempt a hostile takeover.

We believe these provisions will protect our shareholders from coercive or otherwise unfair takeover tactics by requiring potential acquirers to negotiate with our board of directors and by providing our board of directors with more time to assess any acquisition proposal. These provisions are not intended to make us immune from takeovers; however, these provisions will apply even if the offer may be considered beneficial by some shareholders and could delay or prevent an acquisition that our board of directors determines is not in the best interests of us and our shareholders. These provisions may also prevent or discourage attempts to remove and replace incumbent directors. See "Description of Common Stock—Certain Anti-Takeover Provisions" in the Form 10.

In addition, an acquisition or further issuance of our stock could trigger the application of Section 355(e) of the IRC, causing the distribution to be taxable to Exelon. For a discussion of Section 355(e) of the IRC, see "The Separation—Material U.S. Federal Income Tax Consequences of the Separation" in the Form 10. Under the tax matters agreement, we would be required to indemnify Exelon for the resulting tax, and this indemnity obligation might discourage, delay or prevent a change of control that our shareholders may consider favorable.

Our amended and restated articles of incorporation designate the state courts of the Commonwealth of Pennsylvania (or if such state courts do not have jurisdiction, the federal district courts located within the Commonwealth of Pennsylvania) as the sole and exclusive

forum for certain types of actions and proceedings that may be initiated by our shareholders, and the United States federal district courts as the exclusive forum for claims under the Securities Act, which could limit our shareholders' ability to obtain what such shareholders believe to be a favorable judicial forum for disputes with us or our directors, officers or employees.

Our amended and restated articles of incorporation provide that, unless our board of directors consents in writing to an alternative forum, a state court within the Commonwealth of Pennsylvania (or if no such state court has jurisdiction, a federal district court within the Commonwealth of Pennsylvania) will be the sole and exclusive forum for (1) any derivative action or proceeding brought on behalf of the Company (including any derivative suit brought to enforce any liability or duty created by the Exchange Act), (2) any action asserting a claim of breach of a fiduciary duty owed by any current or former director, officer or employee of the Company to the Company or its shareholders, (3) any action asserting a claim against the Company or any of its directors, officers or employees arising pursuant to any provision of the Pennsylvania Business Corporation Law (the "PBCL") or as to which the PBCL confers jurisdiction on the Pennsylvania Courts of Common Pleas or the amended and restated articles of incorporation or amended and restated bylaws or (4) any action asserting a claim against the Company or any of its directors, officers or employees governed by the internal affairs doctrine. The amended and restated articles of incorporation also provide that unless our board of directors consents in writing to an alternative forum, the federal district courts of the United States of America will be the sole and exclusive forum for the resolution of any action asserting a cause of action arising under the Securities Act.

Although the amended and restated articles of incorporation include these exclusive forum provisions, it is possible that a court could rule that these provisions are inapplicable or unenforceable. Our exclusive forum provision will apply to derivative suits brought to enforce any liability or duty created by the Exchange Act, and investors cannot waive compliance with the federal securities laws and the rules and regulations thereunder. These exclusive provisions may limit a shareholder's ability to bring a claim in a judicial forum that the shareholder believes to be favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits. It is possible that a court could find these exclusive forum provisions inapplicable or unenforceable with respect to one or more of the specified types of actions or proceedings, and we may incur additional costs associated with resolving such matters in other jurisdictions, which could materially adversely affect our business, financial condition and results of operations and result in a diversion of the time and resources of our management and board of directors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The following table presents our interests in net electric generating capacity by station at December 31, 2021:

Station[a]	Location	No. of Units	Percent Owned[b]	Primary Fuel Type	Primary Dispatch Type[c]	Net Generation Capacity (MW)[d]
Midwest						
Braidwood	Braidwood, IL	2		Uranium	Base-load	2,386
Byron	Byron, IL	2		Uranium	Base-load	2,347 [e]
LaSalle	Seneca, IL	2		Uranium	Base-load	2,320
Dresden	Morris, IL	2		Uranium	Base-load	1,845 [e]
Quad Cities	Cordova, IL	2	75	Uranium	Base-load	1,403 [f]
Clinton	Clinton, IL	1		Uranium	Base-load	1,080
Michigan Wind 2	Sanilac Co., MI	50	51 [g]	Wind	Intermittent	46 [f]
Beebe	Gratiot Co., MI	34	51 [g]	Wind	Intermittent	42 [f]
Michigan Wind 1	Huron Co., MI	46	51 [g]	Wind	Intermittent	35 [f]
Harvest 2	Huron Co., MI	33	51 [g]	Wind	Intermittent	30 [f]

Station(a)	Location	No. of Units	Percent Owned(b)	Primary Fuel Type	Primary Dispatch Type(c)	Net Generation Capacity (MW)(d)
Harvest	Huron Co., MI	32	51 (g)	Wind	Intermittent	27 (f)
Beebe 1B	Gratiot Co., MI	21	51 (g)	Wind	Intermittent	26 (f)
Blue Breezes	Faribault Co., MN	2		Wind	Intermittent	3
CP Windfarm	Faribault Co., MN	2	51 (g)	Wind	Intermittent	2 (f)
Southeast Chicago	Chicago, IL	8		Gas	Peaking	296 (h)
Clinton Battery Storage	Blanchester, OH	1		Energy Storage	Peaking	10
Total Midwest						11,898
Mid-Atlantic						
Limerick	Sanatoga, PA	2		Uranium	Base-load	2,317
Calvert Cliffs	Lusby, MD	2		Uranium	Base-load	1,789
Peach Bottom	Delta, PA	2	50	Uranium	Base-load	1,324 (f)
Salem	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	995 (f)
Conowingo	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Oakland, MD	28	51 (g)	Wind	Intermittent	36 (f)
Fair Wind	Garrett County, MD	12		Wind	Intermittent	30
Fourmile Ridge	Garrett County, MD	16	51 (g)	Wind	Intermittent	20 (f)
Solar Horizons	Emmitsburg, MD	1	51 (g)	Solar	Intermittent	16 (f)
Solar New Jersey 3	Middle Township, NJ	4	51 (g)	Solar	Intermittent	2 (f)
Muddy Run	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Eddystone, PA	2		Oil/Gas	Peaking	760
Perryman	Aberdeen, MD	5		Oil/Gas	Peaking	404
Croydon	West Bristol, PA	8		Oil	Peaking	391
Handsome Lake	Kennerdell, PA	5		Gas	Peaking	268
Richmond	Philadelphia, PA	2		Oil	Peaking	98
Philadelphia Road	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Eddystone, PA	4		Oil	Peaking	60
Delaware	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Philadelphia, PA	4		Oil	Peaking	52
Falls	Morrisville, PA	3		Oil	Peaking	51
Moser	Lower Pottsgrove Twp., PA	3		Oil	Peaking	51
Chester	Chester, PA	3		Oil	Peaking	39
Schuylkill	Philadelphia, PA	2		Oil	Peaking	30
Salem	Lower Alloways Creek Township, NJ	1	42.59	Oil	Peaking	16 (f)
Total Mid-Atlantic						10,508
ERCOT						
Whitetail	Webb County, TX	57	51 (g)	Wind	Intermittent	47 (f)

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]
Sendero	Jim Hogg and Zapata County, TX	39	51 (g)	Wind	Intermittent	40 (f)
Colorado Bend II	Wharton, TX	3		Gas	Intermediate	1,143
Wolf Hollow II	Granbury, TX	3		Gas	Intermediate	1,115
Handley 3	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	Fort Worth, TX	2		Gas	Peaking	870
Total ERCOT						3,610
New York						
Nine Mile Point	Scriba, NY	2	(i)	Uranium	Base-load	1,675 (f)
FitzPatrick	Scriba, NY	1		Uranium	Base-load	842
Ginna	Ontario, NY	1		Uranium	Base-load	576
Total New York						3,093
Other						
Antelope Valley	Lancaster, CA	1		Solar	Intermittent	242
Bluestem	Beaver County, OK	60	51 (g)(j)	Wind	Intermittent	101 (f)
Shooting Star	Kiowa County, KS	65	51 (g)	Wind	Intermittent	53 (f)
Sacramento PV Energy	Sacramento, CA	4	51 (g)	Solar	Intermittent	30 (f)
Bluegrass Ridge	King City, MO	27	51 (g)	Wind	Intermittent	29 (f)
Conception	Barnard, MO	24	51 (g)	Wind	Intermittent	26 (f)
Cow Branch	Rock Port, MO	24	51 (g)	Wind	Intermittent	26 (f)
Mountain Home	Glenns Ferry, ID	20	51 (g)	Wind	Intermittent	21 (f)
High Mesa	Elmore Co., ID	19	51 (g)	Wind	Intermittent	20 (f)
Echo 1	Echo, OR	21	50.49 (g)	Wind	Intermittent	17 (f)
Cassia	Buhl, ID	14	51 (g)	Wind	Intermittent	15 (f)
Wildcat	Lovington, NM	13	51 (g)	Wind	Intermittent	14 (f)
Echo 2	Echo, OR	10	51 (g)	Wind	Intermittent	10 (f)
Tuana Springs	Hagerman, ID	8	51 (g)	Wind	Intermittent	9 (f)
Greensburg	Greensburg, KS	10	51 (g)	Wind	Intermittent	6 (f)
Echo 3	Echo, OR	6	50.49 (g)	Wind	Intermittent	5 (f)
Three Mile Canyon	Boardman, OR	6	51 (g)	Wind	Intermittent	5 (f)
Loess Hills	Rock Port, MO	4		Wind	Intermittent	5
Denver Airport Solar	Denver, CO	1	51 (g)	Solar	Intermittent	4 (f)
Mystic 8, 9	Charlestown, MA	6		Gas	Intermediate	1,417 (e)
Hillabee	Alexander City, AL	3		Gas	Intermediate	753
Wyman 4	Yarmouth, ME	1	5.9	Oil	Intermediate	34 (f)
West Medway II	West Medway, MA	2		Oil/Gas	Peaking	189
West Medway	West Medway, MA	3		Oil	Peaking	124
Grand Prairie	Alberta, Canada	1		Gas	Peaking	105
Framingham	Framingham, MA	3		Oil	Peaking	31

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]
Total Other						3,291
Total						32,400

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, and Salem, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermittent units are plants with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations and wind and solar facilities reflect a summer rating.
(e) On August 9, 2020, we announced we would permanently cease generation operations at Byron and Dresden nuclear facilities in 2021 and Mystic Unit 8 and 9 in 2024. On September 15, 2021, we reversed the previous decision to retire Byron and Dresden. See Note 7 — Early Plant Retirements of the Notes to the Consolidated Financial Statements for additional information.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects the prior sale of 49% of CRP to a third-party. See Note 21 — Variable Interest Entities of the Notes to Consolidated Financial Statements for additional information.
(h) We have deactivated the site and are evaluating for potential return of service or retirement beyond 2023.
(i) We wholly own Nine Mile Point Unit 1 and have an 82% undivided ownership interest in Nine Mile Point Unit 2.
(j) CRP owns 100% of the Class A membership interests and a tax equity investor owns 100% of the Class B membership interests of the entity that owns the Bluestem generating assets.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies, or generating units being temporarily out of service for inspection, maintenance, refueling, repairs, or modifications required by regulatory authorities.

We maintain property insurance against loss or damage to our principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. — BUSINESS — General. For our insured losses, we are self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on our consolidated financial condition or results of operations.

ITEM 3. LEGAL PROCEEDINGS

We are parties to various lawsuits and regulatory proceedings in the ordinary course of business. For information regarding material lawsuits and proceedings, see Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

PART II

(Dollars in millions except per share data, unless otherwise noted)

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

CEG Parent

Our common stock is listed on the Nasdaq (trading symbol: CEG). It was listed on February 2, 2022 and as of that date there were 326,663,937 shares of common stock outstanding and approximately 82,688 record holders of common stock.

Constellation

Effective January 31, 2022, in connection with the separation, CEG Parent directly holds the entire membership interest in Constellation.

Dividends

Under applicable federal law, Constellation can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Constellation may limit the dividends that it can distribute to CEG Parent. As a Pennsylvania corporation, Constellation is subject to certain restrictions on dividends under Pennsylvania corporate law. Generally, a corporation may only pay dividends under the Pennsylvania Business Corporation Law if the total assets of the corporation would be more than the sum of its total liabilities plus the amount that would be needed, if the corporation were to be dissolved at the time as of which the distribution is measured, to satisfy the preferential rights upon dissolution of shareholders whose preferential rights are superior to those receiving the distribution.

Constellation's revolving credit facility contains a covenant requiring it to maintain a consolidated leverage ratio calculated as the ratio of its consolidated indebtedness to its consolidated earnings before interest, taxes, depreciation and amortization. Maintaining that ratio may affect Constellation's ability to make distributions to the CEG Parent.

We have not paid any dividends to shareholders to date, but our Board of Directors approved a dividend of $180 million in 2022.

First Quarter 2022 Dividend

On February 8, 2022, our Board of Directors declared a regular quarterly dividend of $0.1410 per share on our common stock for the first quarter of 2022. The dividend is payable on Thursday, March 10, 2022, to shareholders of record as of 5 p.m. Eastern time on Friday, February 25, 2022.

ITEM 6. SELECTED FINANCIAL DATA

Not Applicable

Item 7. **MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

(Dollars in millions, unless otherwise noted)

Executive Overview

We are a supplier of clean energy. Our generating capacity consists of nuclear, wind, solar, natural gas and hydroelectric assets. Through our integrated business operations, we sell electricity, natural gas, and other energy related products and sustainable solutions to various types of customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets across multiple geographic regions. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions.

COVID-19. We have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of COVID-19. We provide a critical service to our customers which means that it is paramount that we keep our employees who operate our businesses safe and minimize unnecessary risk of exposure to the virus by taking extra precautions for employees who work in the field and in our facilities. We have implemented work from home policies where appropriate, and imposed travel limitations on employees.

We continue to implement strong physical and cyber-security measures to ensure that our systems remain functional in order to both serve our operational needs with a remote workforce and keep them running to ensure uninterrupted service to our customers.

There were no changes in internal control over financial reporting as a result of COVID-19 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. See ITEM 9A. CONTROLS AND PROCEDURES for additional information.

Unfavorable economic conditions due to COVID-19 resulted in an estimated reduction to our Net income of approximately $170 million for the year ended December 31, 2020. The impact was not material for the year ended December 31, 2021.

We assessed long-lived assets, goodwill, and investments for recoverability and there were no material impairment charges recorded in 2020 or 2021 as a result of COVID-19. See Note 12 — Asset Impairments of the Notes to Consolidated Financial Statements for additional information related to other impairment assessments.

We will continue to monitor developments affecting our workforce, customers, and suppliers and will take additional precautions that we determine to be necessary in order to mitigate the impacts. We cannot predict the full extent of the impacts of COVID-19, which will depend on, among other things, the rate, and public perceptions of the effectiveness, of vaccinations and rate of resumption of business activity.

Significant 2021 Transactions and Developments

Separation from Exelon

On February 21, 2021, Exelon's Board of Directors approved a plan to separate its competitive generation and customer-facing businesses into a stand-alone publicly traded company ("the separation"). Exelon completed the separation on February 1, 2022. In order to govern the ongoing relationships between us and Exelon after the separation, and to facilitate an orderly transition, we and Exelon have entered into several agreements, including a Separation Agreement, Tax Matters Agreement, a Transition Services Agreement, and an Employee Matters Agreement and other ancillary agreements. See Note 24 — Separation from Exelon of the Notes to Consolidated Financial Statements for additional information.

In connection with the separation, we incurred transaction costs of $49 million for the year ended December 31, 2021, which are recorded in Operating and maintenance expense. We expect to incur incremental transaction costs of approximately $150 million and $60 million in 2022 and 2023, respectively. The transaction costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation.

CENG Put Option

EDF had the option to sell its 49.99% equity interest in CENG to us exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. On November 20, 2019, we received notice of EDF's intention to exercise the put option and sell its 49.99% equity interest in CENG to us and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. On August 6, 2021, we entered into a settlement agreement with EDF pursuant to which we, through a wholly owned subsidiary, purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, a credit for EDF's share of the balance of the preferred distribution payable by CENG to us. The difference between the net purchase price and EDF's noncontrolling interest as of the closing date was recorded to Membership Interest in the Consolidated Balance Sheet.

In connection with the settlement agreement, on August 6, 2021, we issued approximately $880 million under a term loan credit agreement to fund the transaction, which will expire on August 5, 2022.

See Note 2 – Mergers, Acquisitions, and Dispositions and Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information.

Clean Energy Law

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorized the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois participated in the CMC procurement process and were awarded contracts that commit each plant to operate through May 31, 2027. Pursuant to these contracts, ComEd will procure CMCs based upon the number of MWhs produced annually by each plant, subject to minimum performance requirements. See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information.

Following enactment of the Clean Energy Law, we announced on September 15, 2021 that we reversed our previous decision to retire Byron and Dresden given the opportunity for additional revenue. In addition, we no longer consider the Braidwood or LaSalle nuclear plants to be at risk for premature retirement. See Note 7 - Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information and Early Retirement of Generation Facilities below.

Early Retirement of Generation Facilities

In August 2020, we announced the intention to retire the Byron Generating Station in September 2021, Dresden Generating Station in November 2021, and Mystic Units 8 and 9 at the expiration of the cost of service commitment in May 2024. As a result, we recognized a $500 million pre-tax impairment for the New England asset group along with certain one-time charges in the third and fourth quarters of 2020, in addition to ongoing annual financial impacts stemming from shortening the expected economic useful lives of these facilities primarily related to accelerated depreciation of plant assets (including any ARC) and accelerated amortization of nuclear fuel.

In the second quarter of 2021, an incremental decline in value resulted in an additional pre-tax impairment charge of $350 million for the New England asset group.

We recorded pre-tax charges of $53 million and $140 million in the second and third quarters of 2021, respectively, for decommissioning-related activities that were not offset for the Byron units due to the inability to recognize a regulatory asset at ComEd.

On September 15, 2021, we reversed our previous decision to early retire Byron and Dresden and the expected economic useful life for both facilities was updated to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. In addition, in the third quarter of 2021, we reversed approximately $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in the third and fourth quarters of 2020 associated with the early retirements.

We recognized pre-tax expenses for Byron, Dresden, and Mystic Units 8 and 9 of $1,458 million for the year ended December 31, 2021, primarily due to accelerated depreciation and amortization of plant assets, partially offset by the reversal of one-time charges for Byron and Dresden.

See Note 7 — Early Plant Retirements, Note 10 — Asset Retirement Obligations, and Note 12 — Asset Impairments of the Notes to Consolidated Financial Statement for additional information.

Impacts of February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions.

The estimated impact to our Net income for the year ended December 31, 2021 arising from these market and weather conditions was a reduction of approximately $800 million. The ultimate impact to our consolidated financial statements may be affected by a number of factors, including the impacts of customer and counterparty defaults and recoveries, any additional solutions to address the financial challenges caused by the event, and related litigation and contract disputes. See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements for additional information.

To offset a portion of the unfavorable impacts, we identified between $370 million and $450 million of enhanced revenue opportunities, deferral of selected non-essential maintenance, and primarily one-time cost savings, which was achieved in 2021.

Agreement for the Sale of a Biomass Facility

On April 28, 2021, we entered into a purchase agreement with ReGenerate Energy Holdings, LLC ("ReGenerate"), under which ReGenerate agreed to purchase our interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, we recorded a pre-tax impairment charge of $140 million. The sale was completed on June 30, 2021 for a net purchase price of $36 million. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Consolidated Financial Statements for additional information.

Agreement for Sale of Our Solar Business

On December 8, 2020, we entered into an agreement for the sale of a significant portion of our solar business, including 360 megawatts of generation in operation or under construction at more than 600 sites across the United States. Completion of the sale occurred on March 31, 2021 for a purchase price of $810 million. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Consolidated Financial Statements for additional information.

Other Key Business Drivers

Power Markets

Section 232 Uranium Petition

On January 16, 2018, two Canadian-owned uranium mining companies with operations in the U.S. jointly submitted a petition to the U.S. Department of Commerce ("DOC") seeking relief under Section 232 of the Trade Expansion Act of 1962 from imports of uranium products, alleging that these imports threaten national security.

The United States Nuclear Fuel Working Group ("Working Group") report was made public on April 23, 2020. The Working Group report states that nuclear power is intrinsically tied to national security, and promises that the U.S. government will take bold actions to strengthen all parts of the nuclear fuel industry in the U.S. It recommends the Agreement Suspending the Antidumping Investigation on Uranium from the Russian Federation (the “Russian Suspension Agreement” or "RSA") be extended and to consider reducing the amount of Russian imports of nuclear fuel. The Russian Suspension Agreement is the historical resolution of a 1991 DOC investigation that found that the Russians had been selling or “dumping” cheap uranium products into the U.S. The RSA has been amended several times in the intervening years to allow Russia to supply limited amounts of uranium products into the U.S. It was set to expire at the end of 2020, but was amended on October 5, 2020 to extend for another 20 years.

The Working Group report should be viewed as policy recommendations that may be implemented by executive agencies, congress, and or regulatory bodies. We cannot predict the outcome of all of the policy changes recommended by the Working Group.

Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps

On February 21, 2019, PJMs Independent Market Monitor (IMM) filed a complaint alleging that the number of performance assessment intervals used to calculate the default offer cap for bids to supply capacity in PJM is too high, resulting in an overstated default offer cap that obviates the need for most sellers to seek unit-specific approval of their offers. The IMM argued that this allows for the exercise of market power. The IMM asked FERC to require PJM to reduce the number of performance assessment intervals used to calculate the opportunity costs of a capacity supplier assuming a capacity obligation. This would, in turn, lower the default offer cap and allow the IMM to review more offers on a unit-specific basis. Several consumer advocates filed a complaint seeking similar relief several months after the IMMs complaint. On March 18, 2021, FERC granted the complaints, finding the current estimate of performance assessment intervals to be excessive compared to the reasonably expected number of performance assessment intervals which results in an unjust and unreasonable default offer cap. FERC did not establish the number of performance assessment intervals that should be used to calculate the default offer cap and instead requested briefs on the matter, including alternative approaches to mitigation in the capacity market. We submitted initial and reply briefs on May 3, 2021 and June 9, 2021, respectively, and an answer to briefs filed by other parties on June 24, 2021. On September 2, 2021, FERC issued an order adopting the IMMs unit-specific avoidable cost offer review methodology and directed PJM to submit a compliance filing establishing new deadlines for offer review and related other activities leading up to the base residual auction for the 2023-2024 planning year and an additional compliance filing revising the PJM Tariff to comply with FERC's order. We filed at FERC for rehearing on this matter on October 4, 2021 which was deemed denied on November 4, 2021. A number of parties, including us, have filed petitions for review of FERC's orders in this proceeding, which remain pending before the Court of Appeals for the District of Columbia Circuit. We cannot predict the outcome of these proceedings or the financial statement impact.

Hedging Strategy

We are exposed to commodity price risk associated with the unhedged portion of our electricity portfolio. We enter into non-derivative and derivative contracts, including options, swaps, and forward and futures contracts, all with credit-approved counterparties, to hedge this anticipated exposure. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis. We may also enter into transactions that are outside of this ratable hedging program. As of December 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 92%-95% and 73%-76% for 2022 and 2023, respectively. We have been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

We procure natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Approximately 50% of our uranium concentrate requirements from 2022 through 2026 are supplied by three suppliers. In the event of non-performance by these or other suppliers, we believe that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Geopolitical developments have the potential to impact delivery from multiple suppliers in the international uranium industry. Non-performance by these counterparties could have a material adverse impact on our consolidated financial statements.

See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements and ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management believes that the accounting policies described below require significant judgment in their application or incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional information on the application of these accounting policies can be found in the Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations

The AROs associated with decommissioning our nuclear units were $12.7 billion at December 31, 2021. The authoritative guidance requires that we estimate our obligation for the future decommissioning of our nuclear generating plants. To estimate that liability, we use an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of nuclear plant retirements in the industry, in recent years, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. The amount of NDT funds could also impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to our current estimates as more information becomes available and could change the timing of plant retirements and the probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the following methodologies and significant estimates and assumptions:

Decommissioning Cost Studies. We use unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of our nuclear units at least every five years, unless circumstances warrant more frequent updates. As part of the annual cost study update process, we evaluate newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors. We use cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal, and other costs. All the nuclear AROs are adjusted each year for updated cost escalation factors.

Probabilistic Cash Flow Models. Our probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. The assumed decommissioning scenarios generally include the following three alternatives: (1) DECON, which assumes major decommissioning activities begin shortly after the cessation of operation, (2) Shortened SAFSTOR, which generally assumes a 30-year delay prior to onset of major decommissioning activities, and (3) SAFSTOR, which assumes the nuclear facility is placed and maintained in such condition during decommissioning so that the nuclear facility can be safely stored and subsequently decontaminated within 60 years after cessation of operations. In each decommissioning scenario, spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined at the time of shutdown and may be influenced by multiple factors including the funding status of the NDT funds at the time of shutdown and regulatory or other commitments.

The assumed plant shutdown timing scenarios include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an initial 20-year license renewal term, (3) the probability of a second, 20-year license renewal term, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. As power market and regulatory environment developments occur, we evaluate and incorporate, as necessary, the impacts of such developments into our nuclear ARO assumptions and estimates.

Our probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. We currently assume DOE will begin accepting SNF from the industry in 2035. The SNF acceptance date assumption is based on management's estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For additional information regarding SNF, see Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements.

Discount Rates. The probability-weighted estimated future cash flows for the various assumed scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. We initially recognize an ARO at fair value and subsequently adjust it for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions. The ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. Increases in the ARO due to upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO cost layer and, therefore, are measured using the average historical CARFR rates used in creating the initial ARO cost layers. If all our future nominal cash flows associated with the ARO were to be discounted at the current prevailing CARFR, the obligation would increase from approximately $12.7 billion to approximately $16.0 billion.

The following table illustrates the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO:

Change in the CARFR applied to the annual ARO update	**(Decrease) Increase to ARO as of December 31, 2021**	
2020 CARFR rather than the 2021 CARFR	$	(490)
2021 CARFR increased by 50 basis points		(600)
2021 CARFR decreased by 50 basis points		750

ARO Sensitivities. Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact of a change in any one of these assumptions to the ARO is highly dependent on how the other assumptions may correspondingly change.

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant:

Change in ARO Assumption		Increase to ARO as of December 31, 2021
Cost escalation studies		
Uniform increase in escalation rates of 50 basis points	$	2,900
Probabilistic cash flow models		
Increase the estimated costs to decommission the nuclear plants by 10 percent		1,110
Increase the likelihood of the DECON scenario by 10 percent and decrease the likelihood of the SAFSTOR scenario by 10 percent[(a)]		480
Shorten each unit's probability weighted operating life assumption by 10 percent[(b)]		1,570
Extend the estimated date for DOE acceptance of SNF to 2040		290

(a) Excludes any sites in which management has committed to a specific decommissioning approach.
(b) Excludes any retired sites.

See Note 1 — Significant Accounting Policies and Note 10 — Asset Retirement Obligations of the Notes to Consolidated Financial Statements for additional information regarding accounting for nuclear AROs.

Unamortized Energy Contract Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that we have acquired. The initial amount recorded represents the difference between the fair value of the contracts at the time of acquisition and the contract value based on the terms of each contract. The unamortized energy contract assets and liabilities are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization of the unamortized energy contract assets and liabilities are recorded through operating revenues or purchased power and fuel expense, depending on the nature of the underlying contract. See Note 13 — Intangible Assets of the Notes to Consolidated Financial Statements for additional information.

Impairment of Long-Lived Assets

We regularly monitor and evaluate the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, or plans to dispose of a long-lived asset significantly before the end of its useful life.

The review of long-lived assets or asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. Forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power and purchases of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. The lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units. The cash flows from our generating units are generally evaluated at a regional portfolio level given the interdependency of cash flows generated from the customer supply and risk management activities within each region. In certain cases, our generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third-party and operations are independent of other generating assets (typically contracted renewables).

On a quarterly basis, we assess our long-lived assets or asset groups for indicators of potential impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates the carrying value of a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the asset or asset groups. This includes significant assumptions of the estimated future cash flows generated by the asset or asset groups and market discount rates. Events and circumstances often do not occur as expected, resulting in differences between prospective financial information and actual results, which may be material. The determination of fair value is driven by both internal assumptions that include significant unobservable inputs (Level 3), such as revenue and generation forecasts, projected capital, maintenance expenditures, and discount rates, as well as information from various public, financial and industry sources.

See Note 12 — Asset Impairments of the Notes to Consolidated Financial Statements for a discussion of asset impairment assessments.

Depreciable Lives of Property, Plant and Equipment

We have significant investments in electric generation assets. These assets are generally depreciated on a straight-line basis, using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for heterogeneous assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are generally conducted periodically if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

Along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of our generating facilities and reassesses the reasonableness of estimated useful lives whenever events or changes in circumstances warrant. When a determination has been made that an asset will be retired before the end of its current estimated useful life, depreciation provisions will be accelerated to reflect the shortened estimated useful life, which could have a material unfavorable impact on future results of operations. See Note 7 — Early Plant Retirements of the Notes to the Consolidated Financial Statements for additional information.

Changes in estimated useful lives of electric generation assets could have a significant impact on future results of operations. See Note 1 — Significant Accounting Policies of the Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment.

Accounting for Derivative Instruments

We use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations. Our derivative activities are in accordance with our Risk Management Policy (RMP). See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information.

We account for derivative financial instruments under the applicable authoritative guidance. Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlying and one or more notional quantities. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance, could result in previously excluded contracts becoming in scope of new authoritative guidance.

All derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, NPNS. Derivatives entered for economic hedging and for proprietary trading purposes are recorded at fair value through earnings.

NPNS. As part of our energy marketing business, we enter contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as NPNS transactions, and are not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the NPNS requires judgment on whether the contract will physically deliver and requires that management ensure compliance with all associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as NPNS are recognized when the underlying physical transaction is completed. Contracts that qualify for NPNS are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period, and the contract is not financially settled on a net basis.

Commodity Contracts. Identification of a commodity contract as an economic hedge requires us to determine that the contract is in accordance with the RMP. We reassess our economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of the authoritative guidance, we make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether to enter derivative transactions, and in determining the initial accounting treatment for derivative transactions. Under the authoritative guidance for fair value measurements, we categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value.

Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are generally categorized in Level 1 in the fair value hierarchy.

Certain derivative pricing is verified using indicative price quotations available through brokers or over-the-counter, online exchanges. The price quotations reflect the average of the mid-point of the bid-ask spread from observable markets that we believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. Our derivatives are traded predominantly at liquid trading points. The remaining derivative contracts are valued using models that consider inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps, and options, the model inputs are generally observable. Such instruments are categorized in Level 2.

For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs and are categorized in Level 3.

We consider nonperformance risk, including credit risk in the valuation of derivative contracts, and both historical and current market data in our assessment of nonperformance risk. The impacts of nonperformance and credit risk to date have generally not been material to the financial statements.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 18 — Fair Value of Financial Assets and Liabilities and Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information regarding derivative instruments.

Taxation

Significant management judgment is required in determining our provision for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. We account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the consolidated financial statements.

We evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and our intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. We also assess negative evidence, such as the expiration of historical operating loss or tax credit carryforwards, that could indicate our inability to realize our deferred tax assets. Based on the combined assessment, we record valuation allowances for deferred tax assets when it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, our forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. See Note 14 — Income Taxes of the Notes to Consolidated Financial Statements for additional information.

Accounting for Loss Contingencies

In the preparation of our financial statements, we make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amount recorded may differ from the actual expense incurred when the uncertainty is resolved. Such difference could have a significant impact in the consolidated financial statements.

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which we will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, regulations, and the requirements of local governmental authorities. In addition, periodic reviews are performed to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact in the consolidated financial statements. See Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements for additional information.

Other, Including Personal Injury Claims. Prior to our separation from Exelon, we were self-insured for general liability, automotive liability, and workers' compensation claims. Upon separation, we now maintain insurance coverage for general liability, automotive liability, and workers' compensation and are self-insured to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. For personal injury claims, we are self-insured to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. We have reserves for both open claims asserted, and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material impact to the consolidated financial statements.

Revenue Recognition

Sources of Revenue and Determination of Accounting Treatment. We earn revenue from various business activities including: the sale of power and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail) and the provision of other energy-related non-regulated products and services.

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. We primarily apply the Revenue from Contracts with Customers and Derivatives Revenues guidance to recognize revenue, as discussed in more detail below.

Revenue from Contracts with Customers. We recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power, natural gas and other energy-related commodities and services are provided to the customer. Transactions within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as NPNS and spot-market energy commodity sales, including settlements with ISOs.

The determination of our retail power and natural gas sales to individual customers is based on systematic readings of customer meters, generally monthly. Energy delivered to customers that has not yet been billed as of the reporting period is estimated and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is based upon individual customer meter readings, forecasted volumes, and applicable rates. See Note 1 — Significant Accounting Policies of the Notes to Consolidated Financial Statements for additional information.

Derivative Revenues. We record revenues and expenses using the mark-to-market method of accounting for transactions that are accounted for as derivatives. These derivative transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable, unrealized gains and losses from changes in the fair value of open contracts, and realized gains and losses.

Results of Operations

For discussion of the year ended December 31, 2020 compared to the year ended December 31, 2019, refer to MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the Form 10.

	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 19,649	$ 17,603	$ 2,046
Operating expenses			
Purchased power and fuel	12,163	9,585	(2,578)
Operating and maintenance	4,555	5,168	613
Depreciation and amortization	3,003	2,123	(880)
Taxes other than income taxes	475	482	7
Total operating expenses	20,196	17,358	(2,838)
Gain on sales of assets and businesses	201	11	190
Operating (loss) income	(346)	256	(602)
Other income and (deductions)			
Interest expense, net	(297)	(357)	60
Other, net	795	937	(142)
Total other income and (deductions)	498	580	(82)
Income before income taxes	152	836	(684)
Income taxes	225	249	24
Equity in losses of unconsolidated affiliates	(10)	(8)	(2)
Net (loss) income	(83)	579	(662)
Net income (loss) attributable to noncontrolling interests	122	(10)	132
Net (loss) income attributable to membership interest	$ (205)	$ 589	$ (794)

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020. **Net income attributable to membership interest** decreased by $794 million primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with our previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed

on September 15, 2021, and our decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;

- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date;
- Impairments of the New England asset group, the Albany Green Energy biomass facility, and a wind project, partially offset by the absence of an impairment of the New England asset group in the third quarter of 2020;
- Higher net unrealized and realized losses on equity investments; and
- The absence of prior year one-time tax settlements.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized and realized gains on NDT funds;
- Absence of one time charges recorded in 2020 associated with our decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the reversal of one-time charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;
- Favorable sales and hedges of excess emission credits;
- Favorable commodity prices on fuel hedges;
- Lower nuclear fuel costs due to accelerated amortization of nuclear fuel and lower prices; and
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices.

Operating revenues. The basis for our reportable segments is the integrated management of our electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Our hedging strategies and risk metrics are also aligned with these same geographic regions. Our five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 — Segment Information of the Notes to Consolidated Financial Statements for additional information on these reportable segments.

The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall operating revenues or results of operations.

For the year ended December 31, 2021 compared to 2020, Operating revenues by region were as follows:

			2021 vs. 2020	
	2021	2020	Variance	% Change[(a)]
Mid-Atlantic	$ 4,584	$ 4,645	$ (61)	(1.3) %
Midwest	4,060	4,024	36	0.9 %
New York	1,575	1,431	144	10.1 %
ERCOT	1,181	958	223	23.3 %
Other Power Regions	4,890	4,002	888	22.2 %
Total electric revenues	16,290	15,060	1,230	8.2 %
Other	3,992	2,433	1,559	64.1 %
Mark-to-market (losses) gains	(633)	110	(743)	
Total Operating revenues	$ 19,649	$ 17,603	$ 2,046	11.6 %

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(a) % Change in mark-to-market is not a meaningful measure.

Sales and Supply Sources. Our sales and supply sources by region are summarized below:

			2021 vs. 2020	
Supply Source (GWhs)	2021	2020	Variance	% Change
Nuclear Generation[(a)]				
Mid-Atlantic	53,589	52,202	1,387	2.7 %
Midwest	93,107	96,322	(3,215)	(3.3)%
New York	28,291	26,561	1,730	6.5 %
Total Nuclear Generation	174,987	175,085	(98)	(0.1)%
Natural Gas, Oil and Renewables				
Mid-Atlantic	2,271	2,206	65	2.9 %
Midwest	1,083	1,240	(157)	(12.7)%
New York	1	4	(3)	(75.0)%
ERCOT	13,187	11,982	1,205	10.1 %
Other Power Regions	9,995	11,121	(1,126)	(10.1)%
Total Natural Gas, Oil and Renewables	26,537	26,553	(16)	(0.1)%
Purchased Power				
Mid-Atlantic	13,576	22,487	(8,911)	(39.6)%
Midwest	561	770	(209)	(27.1)%
ERCOT	3,256	5,636	(2,380)	(42.2)%
Other Power Regions	50,212	51,079	(867)	(1.7)%
Total Purchased Power	67,605	79,972	(12,367)	(15.5)%
Total Supply/Sales by Region				
Mid-Atlantic	69,436	76,895	(7,459)	(9.7)%
Midwest	94,751	98,332	(3,581)	(3.6)%
New York	28,292	26,565	1,727	6.5 %
ERCOT	16,443	17,618	(1,175)	(6.7)%
Other Power Regions	60,207	62,200	(1,993)	(3.2)%
Total Supply/Sales by Region	269,129	281,610	(12,481)	(4.4)%

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(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants. Includes the total output for fully owned plants and the total output for CENG prior to the acquisition of EDF's interest on August 6, 2021 as CENG was fully consolidated. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Consolidated Financial Statements for additional information on our acquisition of EDF's interest in CENG.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for our plants, which reflects ownership percentage of stations operated by us, excluding Salem, which is operated by PSEG. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. We consider capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. We have included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2021	2020
Nuclear fleet capacity factor	94.5 %	95.4 %
Refueling outage days	262	260
Non-refueling outage days	34	19

ZEC Prices. We are compensated through state programs for the carbon-free attributes of our nuclear generation. ZEC prices have a significant impact on operating revenues. The following table presents the average ZEC prices ($/MWh) for each of our major regions in which state programs have been enacted. Prices reflect the weighted average price for the various delivery periods within each calendar year.

			2021 vs. 2020	
State (Region)[(a)]	2021	2020	Variance	% Change
New Jersey (Mid-Atlantic)	$ 10.00	$ 10.00	$ —	— %
Illinois (Midwest)	16.50	16.50	—	— %
New York (New York)	20.93	19.59	1.34	6.8 %

(a) See Note 7 — Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information on the plants receiving payments through state programs.

Capacity Prices. We participate in capacity auctions in each of our major regions, except ERCOT which does not have a capacity market. We also incur capacity costs associated with load served, except in ERCOT. Capacity prices have a significant impact on our operating revenues and purchased power and fuel. The following table presents the average capacity prices ($/MW Day) for each of our major regions. Prices reflect the weighted average price for the various auction periods within each calendar year.

			2021 vs. 2020	
Location (Region)	2021	2020	Variance	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic and Midwest)	$ 174.96	$ 159.50	$ 15.46	9.7 %
ComEd (Midwest)	192.45	194.22	(1.77)	(0.9)%
Rest of State (New York)	98.35	47.81	50.54	105.7 %
Southeast New England (Other)	163.66	200.69	(37.03)	(18.5)%

Electricity Prices. The price of electricity has a significant impact on our operating revenues and purchased power cost. The following table presents the average day-ahead around-the-clock price ($/MWh) for each of our major regions.

Location (Region)	2021	2020	2021 vs. 2020 Variance	2021 vs. 2020 % Change
PJM West (Mid-Atlantic)	$ 38.91	$ 20.95	$ 17.96	85.7 %
ComEd (Midwest)	34.76	18.96	15.80	83.3 %
Central (New York)	29.90	16.36	13.54	82.8 %
North (ERCOT)	146.63	22.03	124.60	565.6 %
Southeast Massachusetts (Other)[a]	46.38	23.57	22.81	96.8 %

(a) Reflects New England, which comprises the majority of the activity in the Other region.

For the year ended December 31, 2021 compared to 2020, changes in **Operating revenues** by region were approximately as follows:

	2021 vs. 2020 Variance	2021 vs. 2020 % Change[a]	Description
Mid-Atlantic	$ (61)	(1.3)%	• unfavorable wholesale load revenue of $(520) primarily due to lower volumes; partially offset by • favorable settled economic hedges of $365 due to settled prices relative to hedged prices • favorable retail load revenue of $95 primarily due to higher prices
Midwest	36	0.9 %	• favorable net wholesale load and generation revenue of $540 primarily due to higher prices, partially offset by decreased generation due to higher nuclear outage days; partially offset by • unfavorable settled economic hedges of $(525) due to settled prices relative to hedged prices
New York	144	10.1 %	• favorable nuclear generation revenue of $75 primarily due to higher prices and lower nuclear outage days • favorable ZEC revenue of $70 due to higher prices and higher nuclear generation
ERCOT	223	23.3 %	• favorable retail load revenue of $140 primarily due to higher prices in part due to the February 2021 extreme cold weather event • favorable settled economic hedges of $65 due to settled prices relative to hedged prices
Other Power Regions	888	22.2 %	• favorable settled economic hedges of $655 due to settled prices relative to hedged prices • favorable retail load revenue of $535 due to higher prices and higher volumes; partially offset by • unfavorable wholesale load revenue of $(380) primarily due to lower volumes
Other	1,559	64.1 %	• favorable gas revenue of $1,375 primarily due to higher prices in part due to the February 2021 extreme cold weather event
Mark-to-market[b]	(743)		• losses on economic hedging activities of $(633) in 2021 compared to gains of $110 in 2020
Total	$ 2,046	11.6 %	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

Purchased power and fuel. See Operating revenues above for discussion of our reportable segments and hedging strategies and for supplemental statistical data, including supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall purchased power and fuel expense or results of operations, and accelerated nuclear fuel amortization associated with nuclear decommissioning.

For the year ended December 31, 2021 compared to 2020, Purchased power and fuel by region were as follows:

			2021 vs. 2020	
	2021	2020	Variance	% Change[(a)]
Mid-Atlantic	$ 2,320	$ 2,442	$ 122	5.0 %
Midwest	1,343	1,121	(222)	(19.8)%
New York	414	434	20	4.6 %
ERCOT	2,006	532	(1,474)	(277.1)%
Other Power Regions	3,999	3,336	(663)	(19.9)%
Total electric purchased power and fuel	10,082	7,865	(2,217)	(28.2)%
Other	3,279	1,904	(1,375)	(72.2)%
Mark-to-market gains	(1,198)	(184)	1,014	
Total purchased power and fuel	$ 12,163	$ 9,585	$ (2,578)	(26.9)%

(a) % Change in mark-to-market is not a meaningful measure.

For the year ended December 31, 2021 compared to 2020, changes in **Purchased power and fuel** by region were approximately as follows:

	2021 vs. 2020		
	Variance	% Change[(a)]	Description
Mid-Atlantic	$ 122	5.0 %	• favorable purchased power and net capacity impact of $80 primarily due to higher nuclear generation, lower load and higher capacity prices earned partially offset by lower cleared capacity volumes • favorable settlement of economic hedges of $70 due to settled prices relative to hedged prices
Midwest	(222)	(19.8)%	• unfavorable purchased power and net capacity impact of $(330) primarily due to higher energy prices, lower nuclear generation, lower cleared capacity volumes, and lower capacity prices; partially offset by • favorable nuclear fuel cost of $75 primarily due to accelerated amortization of nuclear fuel and lower nuclear fuel prices
New York	20	4.6 %	• favorable settlement of economic hedges of $45 due to settled prices relative to hedged prices; partially offset by • unfavorable purchased power and net capacity impact of $(40) primarily due to higher energy prices partially offset by higher nuclear generation and higher capacity prices earned
ERCOT	(1,474)	(277.1)%	• unfavorable purchased power of $(755) primarily due to higher energy prices primarily during the February 2021 extreme cold weather event • unfavorable settlement of economic hedges of $(535) due to settled prices relative to hedged prices • unfavorable fuel cost of $(170) primarily due to higher gas prices
Other Power Regions	(663)	(19.9)%	• unfavorable purchased power and net capacity impact of $(855) primarily due to higher energy prices, lower generation, lower cleared capacity volumes, and lower capacity prices • unfavorable fuel cost of $(80) primarily due to higher gas prices; partially offset by • net favorable environmental products activity of $270 primarily driven by favorable emissions activity partially offset by unfavorable RPS activity
Other	(1,375)	(72.2)%	• unfavorable net gas purchase costs and settlement of economic hedges of $(1,150) • unfavorable accelerated nuclear fuel amortization associated with announced early plant retirements of $(90)
Mark-to-market[(b)]	1,014		• gains on economic hedging activities of $1,198 in 2021 compared to gains of $184 in 2020
Total	$ (2,578)	(26.9)%	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

The changes in **Operating and maintenance expense** consisted of the following:

	2021 vs. 2020 (Decrease) Increase
Plant retirements and divestitures[(a)]	$ (484)
ARO update	(109)
Labor, other benefits, contracting, and materials	(64)
Insurance	(45)
Cost management program	(34)
Nuclear refueling outage costs, including the co-owned Salem plants	(16)
Corporate allocations	(14)
Acquisition related costs	15
Credit loss expense	21
Asset impairments	27
Separation costs	49
Other	41
Total decrease	$ (613)

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(a) Primarily reflects contractual offset of accelerated depreciation and amortization associated with our previous decision to early retire the Byron and Dresden nuclear facilities. See Note 10 — Asset Retirement Obligations of the Notes to Consolidated Financial Statements for additional information.

Depreciation and amortization expense increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to the accelerated depreciation and amortization associated with our previous decision to early retire the Byron and Dresden nuclear facilities. This decision was reversed on September 15, 2021 and depreciation for Byron and Dresden was adjusted beginning September 15, 2021 to reflect the extended useful life estimates. A portion of this accelerated depreciation and amortization is offset in Operating and maintenance expense.

Gain on sales of assets and businesses increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to gains on sales of equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021 and a gain on sale of our solar business.

Interest expense, net decreased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to decreased expense related to the CR nonrecourse senior secured term loan credit facility and interest rate swaps, and decreases in interest rates. See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on the CR credit facility and interest rate swaps.

Other, net decreased for the year ended December 31, 2021 compared to the same period in 2020, due to activity described in the table below:

	2021	2020
Net unrealized gains on NDT funds[(a)]	$ 204	$ 391
Net realized gains on sale of NDT funds[(a)]	381	70
Interest and dividend income on NDT funds[(a)]	98	90
Contractual elimination of income tax expense[(b)]	226	180
Net unrealized (losses) gains from equity investments[(c)]	(160)	186
Other	46	20
Total other, net	$ 795	$ 937

(a) Unrealized gains, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units. In addition, also includes unrealized gains, realized gains, and interest and dividend income on the NDT funds associated with the Byron units as decommissioning-related impacts were not offset starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With the September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of the Notes to Consolidated Financial Statements for additional information.
(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement Units.
(c) Net unrealized gains and losses from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Effective income tax rates were 148.0% and 29.8% for the years ended December 31, 2021 and 2020, respectively. The higher effective tax rate in 2021 is primarily due to the impacts of the February 2021 extreme cold weather event on Income before income taxes. See Note 14 — Income Taxes of the Notes to Consolidated Financial Statements for additional information.

Net income attributable to noncontrolling interests increased for the year ended December 31, 2021 compared to the same period in 2020, primarily due to CENG's results of operations prior to our acquisition of EDF's interest in CENG on August 6, 2021.

Liquidity and Capital Resources

For discussion of the year ended December 31, 2020 compared to the year ended December 31, 2019, refer to Liquidity and Capital Resources of MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the Form 10.

All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

Our operating and capital expenditures requirements are provided by internally generated cash flows from operations, the sale of certain receivables, as well as funds from external sources in the capital markets and through bank borrowings. Our business is capital intensive and requires considerable capital resources. We annually evaluate our financing plan and credit line sizing, focusing on maintaining our investment grade ratings while meeting our cash needs to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet our needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). Our access to external financing on reasonable terms depends on our credit ratings and current overall capital market business conditions. If these conditions deteriorate to the extent that we no longer have access to the capital markets at reasonable terms, we have access to credit facilities with aggregate bank commitments of $5.7 billion. We utilize our credit facilities to support our commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for additional information. We expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on our debt and credit agreements.

Pursuant to the Separation Agreement between us and Exelon, we received a cash payment of $1.75 billion from Exelon on January 31, 2022. See Note 24 — Separation from Exelon of the Notes to Consolidated Financial Statements for additional information on the separation.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are typically based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant's owners or parent companies would be required to take steps, such as providing financial guarantees through surety bonds, letters of credit, or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 10 - Asset Retirement Obligations of the Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT funds could appreciate in value. A shortfall could require that we address the shortfall by providing additional financial assurances, such as surety bonds, letters of credit, or parent company guarantees for our share of the funding assurance. However, the amount of any assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT fund investment performance going forward. No later than two years after shutting down a plant, we must submit a PSDAR to the NRC that includes the planned option for decommissioning the site.

Upon issuance of any required financial assurances, subject to satisfying various regulatory preconditions, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, under the regulations, the NRC must approve an exemption in order for us to utilize the NDT funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs, if applicable). Any amounts not covered by an exemption would be borne by us without reimbursement.

As of December 31, 2021, we are not required to provide any additional financial assurance for TMI Unit 1 under the SAFSTOR scenario that is the planned decommissioning option, as described in the TMI Unit 1 PSDAR filed with the NRC on April 5, 2019. On October 16, 2019, the NRC granted our exemption request to use the TMI Unit 1 NDT funds for spent fuel management costs. An additional exemption request to allow the TMI Unit 1 NDT funds to be used for site restoration costs was submitted to the NRC on May 20, 2021 and is pending NRC review.

Cash Flows from Operating Activities

Our cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Our future cash flows from operating activities may be affected by future demand for, and market prices of, energy and our ability to continue to produce and supply power at competitive costs, as well as to obtain collections from customers and the sale of certain receivables.

See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements for additional information on regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the years ended December 31, 2021 and 2020:

(Decrease) increase in cash flows from operating activities		
Net income	$	(662)
Adjustments to reconcile net income to cash:		
Non-cash operating activities		(287)
Option premiums paid, net		(199)
Collateral posted, net		(609)
Income taxes		70
Pension and non-pension postretirement benefit contributions		(4)
Changes in working capital and other noncurrent assets and liabilities		(231)
Decrease in cash flows from operating activities	$	(1,922)

Changes in our cash flows from operations were generally consistent with changes in results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for 2021 and 2020 were as follows:

- See Note 22 —Supplemental Financial Information of the Notes to Consolidated Financial Statements and the Consolidated Statement of Cash Flows for additional information on **non-cash operating activities**.

- **Option premiums paid** relate to options contracts that we purchase and sell as part of our established policies and procedures to manage risks associated with market fluctuations in commodity prices. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on derivative contracts.
- Depending upon whether we are in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from our counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the over-the-counter markets. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on collateral.
- See Note 14 —Income Taxes of the Notes to Consolidated Financial Statements and the Consolidated Statements of Cash Flows for additional information on **income taxes.**
- **Changes in working capital and other noncurrent assets and liabilities** include a decrease in Accounts receivable resulting from the impact of cash received in 2020 related to the revolving accounts receivable financing arrangement entered into on April 8, 2020 and an increase in Accounts payable and accrued expenses resulting from the impact of certain penalties for natural gas delivery associated with the February 2021 extreme cold weather event and increases in natural gas prices. See Note 6 —Accounts Receivable and Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information on the sales of customer accounts receivable and on the February 2021 extreme cold weather event, respectively.

Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the years ended December 31, 2021 and 2020:

Increase (decrease) in cash flows from investing activities		
Capital expenditures	$	418
Investment in NDT fund sales, net		(18)
Collection of DPP		131
Proceeds from sales of assets and businesses		832
Other investing activities		(39)
Increase in cash flows from investing activities	$	1,324

Significant investing cash flow impacts for 2021 and 2020 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. See the "Credit Matters and Cash Requirements" section below for additional information on projected capital expenditure spending.
- See Note 6 — Accounts Receivable of the Notes to Consolidated Financial Statements for additional information on the **Collection of DPP**.
- **Proceeds from sales of assets and businesses** increased primarily due to the sale of a significant portion of our solar business and a biomass facility and proceeds received on sales of equity investments. See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Consolidated Financial Statements for additional information on the sale of our solar business and biomass facility.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the years ended December 31, 2021 and 2020:

Increase (decrease) in cash flows from financing activities	
Changes in short-term borrowings, net	$ 722
Long-term debt, net	1,776
Changes in money pool with Exelon	(570)
Acquisition of noncontrolling interest	(885)
Distributions to member	(98)
Other financing activities	24
Increase in cash flows from financing activities	$ 969

Significant financing cash flow impacts for 2021 and 2020 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. Refer to Note 17 - Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on short-term borrowings.
- **Long-term debt, net,** varies due to debt issuances and redemptions each year. Refer to debt issuances and redemptions tables below for additional information.
- **Changes in money pool with Exelon** are driven by short-term borrowing needs. Exelon operated a money pool for its subsidiaries that provided an additional short-term borrowing option that was generally more favorable to the borrowing participants than the cost of external financing.
- See Note 2 — Mergers, Acquisitions, and Dispositions of the Notes to Consolidated Financial Statements for additional information related to the **acquisition** of CENG noncontrolling interest.
- **Other financing activities** primarily consists of debt issuance costs. See debt issuances table below for additional information on debt issuances.

Debt Issuances and Redemptions

See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on our long-term debt. Debt activity for 2021 and 2020 was as follows:

During 2021, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
West Medway II Nonrecourse Debt[a]	LIBOR + 3%[b]	March 31, 2026	$ 150	Funding for general corporate purposes.
Energy Efficiency Project Financing[c]	2.53% - 4.24%	January 31, 2022 - February 28, 2022	2	Funding to install energy conservation measures.

(a) See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on nonrecourse debt.
(b) The nonrecourse debt has an average blended interest rate.
(c) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During 2020, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
Senior Notes	3.25 %	June 1, 2025	$ 900	Repay existing indebtedness and for general corporate purposes.
Constellation Renewables Nonrecourse Debt[a]	LIBOR + 2.75%	December 15, 2027	750	Repay existing indebtedness and for general corporate purposes.
Energy Efficiency Project Financing[b]	2.53% - 3.95%	February 28, 2021 - March 31, 2021	6	Funding to install energy conservation measures.

(a) See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information of nonrecourse debt.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

During 2021, the following long-term debt was retired and/or redeemed:

Type[a]	Interest Rate	Maturity	Amount
Continental Wind Nonrecourse Debt[b]	6.00%	February 28, 2033	$ 35
CR Nonrecourse Debt[b]	3-month LIBOR + 2.50%[c]	December 15, 2027	17
SolGen Nonrecourse Debt[b]	3.93%	September 30, 2036	7
Antelope Valley DOE Nonrecourse Debt[b][d]	2.29% - 3.56%	January 5, 2037	24
West Medway II Nonrecourse Debt[b]	LIBOR + 3%[e]	March 31, 2026	13
RPG Nonrecourse Debt[b]	4.11%	March 31, 2035	9

(a) As part of the 2012 merger, Exelon entered intercompany loan agreements that mirrored the terms and amounts of third-party debt obligations. In connection with the separation, on January 31, 2022, we paid cash to Exelon Corporate of $258 million to settle the intercompany loan. See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on the mirror debt.
(b) See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on nonrecourse debt.
(c) The interest rate was amended to 3-month LIBOR + 2.50% on June 16, 2021.
(d) On January 5, 2022, we redeemed $6 million of 2.29% - 3.56% Antelope Valley DOE nonrecourse debt.
(e) The nonrecourse debt has an average blended interest rate.

During 2020, the following long-term debt was retired and/or redeemed:

Type	Interest Rate	Maturity	Amount
Senior Notes	2.95%	January 15, 2020	$ 1,000
Senior Notes	4.00%	October 1, 2020	550
Senior Notes[a]	5.15%	December 1, 2020	550
Tax-Exempt Bonds	2.50% - 2.70%	December 1, 2025 - June 1, 2036	412
CR Nonrecourse Debt[b]	3-month LIBOR + 3.00%	November 30, 2024	796
Continental Wind Nonrecourse Debt[b]	6.00%	February 28, 2033	33
Antelope Valley DOE Nonrecourse Debt[b]	2.29% - 3.56%	January 5, 2037	23
RPG Nonrecourse Debt[b]	4.11%	March 31, 2035	9
Energy Efficiency Project Financing	3.71%	December 31, 2020	4
NUKEM	3.15%	September 30, 2020	3
SolGen Nonrecourse Debt	3.93%	September 30, 2036	3
Energy Efficiency Project Financing	4.12%	November 30, 2020	1

(a) The senior notes are legacy mirror debt that were previously held at Exelon and Constellation. As part of the 2012 merger, Exelon and Constellation assumed intercompany loan agreements that mirrored the terms and amounts of external

obligations held by Exelon, resulting in notes payable to related parties in the Consolidated Balance Sheets. See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on the mirror debt.
(b) See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

From time to time and as market conditions warrant, we may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt.

Credit Matters and Cash Requirements

We fund liquidity needs for capital expenditures, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. As of December 31, 2021, our credit facilities included $6.6 billion in aggregate total commitments of which $3.4 billion was available to support additional commercial paper and of which no financial institution has more than 8% of the aggregate commitments. In connection with our separation from Exelon, we entered into two new credit agreements that replaced our syndicated revolving credit facility. Under the new agreements, we have access to credit facilities with aggregate bank commitments of $5.7 billion. We had access to the commercial paper markets and had availability under our revolving credit facilities during 2021 to fund our short-term liquidity needs, when necessary. We used our available credit facilities to manage short-term liquidity needs as a result of the impacts of the February 2021 extreme cold weather event. We routinely review the sufficiency of our liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. We closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I, ITEM 1A. RISK FACTORS for additional information regarding the effects of uncertainty in the capital and credit markets.

We believe our cash flow from operating activities, access to credit markets and our credit facilities provide sufficient liquidity to support the estimated future cash requirements discussed below.

If we lost our investment grade credit rating as of December 31, 2021, we would have been required to provide incremental collateral of approximately $2.1 billion to meet collateral obligations for derivatives, non-derivatives, NPNS, and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which was well within the $3.4 billion of available credit capacity of our revolver as of December 31, 2021. See Note 16 — Derivative Financial Instruments and Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information.

Capital Expenditures

Our most recent estimate of capital expenditures for plant additions and improvements is approximately $1.7 billion for 2022 and approximately $2.9 billion for the period from 2023 to 2024. Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Approximately 50% of projected capital expenditures are for the acquisition of nuclear fuel, with the remaining amounts primarily reflecting additions and upgrades to existing generation facilities (including material condition improvements during nuclear refueling outages).

We anticipate that we will fund capital expenditures with a combination of internally generated funds and borrowings.

Cash Requirements for Other Financial Commitments

The following table summarizes our future estimated cash payments as of December 31, 2021 under existing financial commitments:

	2022	Beyond 2022	Total	Time Period
Long-term debt	$ 1,218	$ 4,878	$ 6,096	2022 - 2042
Interest payments on long-term debt[(a)]	252	3,011	3,263	2022 - 2042
Operating leases[(b)]	35	611	646	2022 - 2056
Purchase power obligations[(c)]	620	1,109	1,729	2022 - 2036
Fuel purchase agreements[(d)]	1,020	4,452	5,472	2022 - 2054
Other purchase obligations[(e)]	1,159	1,231	2,390	2022 - 2046
SNF obligation	—	1,210	1,210	2022 - 2035
Pension contributions[(f)]	192	93	285	2022 - 2027
Total cash requirements	$ 4,496	$ 16,595	$ 21,091	

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2021 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2021.
(b) Capacity payments associated with contracted generation lease agreements are net of sublease and capacity offsets of $57 million and $315 million for 2022 and thereafter, respectively and $372 million in total.
(c) Purchase power obligations primarily include expected payments for REC purchases and capacity payments associated with contracted generation agreements, which may be reduced based on plant availability. Expected payments exclude payments on renewable generation contracts that are contingent in nature.
(d) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services.
(e) Represents the future estimated value at December 31, 2021 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into with third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) These amounts represent our expected contributions to our qualified pension plans. Qualified pension contributions for years after 2027 are not included.

See Note 19 — Commitments and Contingencies and Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information of our other commitments potentially triggered by future events. Additionally, see below for where to find additional information regarding the financial commitments in the table above in the Notes to the Consolidated Financial Statements.

Item	Location within Notes to the Consolidated Financial Statements
Long-term debt	Note 17 — Debt and Credit Agreements
Interest payments on long-term debt	Note 17 — Debt and Credit Agreements
Operating leases	Note 11 — Leases
SNF obligation	Note 19 — Commitments and Contingencies

Project Financing

Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by a specific asset or portfolio of assets. Borrowings under these agreements are secured by the assets and equity of each respective project. Lenders do not have recourse against us in the event of a default. If a project financing entity does not maintain compliance with its specific debt covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment were not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to repay the debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on project finance credit facilities and nonrecourse debt.

Credit Facilities

We meet our short-term liquidity requirements primarily through the issuance of commercial paper. We may use our credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 17 — Debt and Credit Agreements of the Notes to Consolidated Financial Statements for additional information on our credit facilities.

Capital Structure

At December 31, 2021, our capital structure consisted of the following:

	Percentage of Capital Structure
Commercial paper and notes payable	10 %
Long-term debt	29 %
Long-term debt to affiliates	2 %
Member's equity	59 %

Security Ratings

Our access to the capital markets, including the commercial paper market, and our financing costs in those markets, may depend on our securities ratings.

Our borrowings are not subject to default or prepayment as a result of a downgrade of our securities, although such a downgrade could increase fees and interest charges under our credit agreements.

As part of the normal course of business, we enter into contracts that contain express provisions or otherwise permit us and our counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if we are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of additional collateral. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on collateral provisions.

On February 24, 2021, S&P lowered our senior unsecured debt rating to 'BBB-' from 'BBB' in response to the financial impacts of the February 2021 weather event and outages at our Texas-based generating assets. See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information. The S&P rating change did not materially impact our financial statements. Furthermore, there were no material increases in required collateral or financial assurances or material impacts to our anticipated access to liquidity or cost of financing. At separation S&P and Moody's affirmed the senior unsecured ratings of BBB- and Baa2, respectively. Fitch also affirmed their final rating of BBB, prior to formally withdrawing coverage on January 5th. We will only be engaging S&P and Moody's for ratings coverage following separation.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates, and equity prices. We manage these risks through risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. Historically, reporting on risk management issues has been to Exelon's Risk Management Committee and the Risk Committee of Exelon's Board of Directors. After separation, reporting on risk management issues will be to the Executive Committee, the Risk Management Committees of our generation and customer-facing businesses, and the Audit and Risk Committee of the Board of Directors.

Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental, regulatory and environmental policies, and other factors. To the extent the total amount of energy we generate and purchase differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in commodity prices. We seek to mitigate our commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Electricity available from our owned or contracted generation supply in excess of our obligations to customers is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, we enter into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures. We use derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. We expect the settlement of the majority of our economic hedges will occur during 2022 through 2024.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on our owned and contracted generation positions which have not been hedged. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis. We may also enter transactions that are outside of this ratable hedging program. As of December 31, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 92%-95% and 73%-76% for 2022 and 2023, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generation based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges, CMC payments, and certain non-derivative contracts.

A portion of our hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for our entire economic hedge portfolio associated with a $5/MWh reduction in the annual average around-the-clock energy price based on December 31, 2021 market conditions and hedged position would be a decrease in pre-tax net income of approximately $20 million and $243 million for 2022 and 2023, respectively. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. We actively manage our portfolio to mitigate market price risk exposure for our unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in our portfolio. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

We procure natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make our procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of our uranium concentrate requirements from 2022 through 2026 are supplied by three suppliers. In the event of non-performance by these or other suppliers, we believe that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Geopolitical developments, including the Russian Ukraine conflict and United States sanctions against Russia, have the potential to impact delivery from multiple suppliers in the international uranium industry. Non-performance by these counterparties could have a material adverse impact in our financial statements.

Trading and Non-Trading Marketing Activities

The following table detailing our trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in our commodity mark-to-market net asset or liability balance sheet position from December 31, 2019 to December 31, 2021. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2021 and 2020.

	Mark-to-market Energy Contract Net Assets (Liabilities)
Balance as of December 31, 2019	$ 868 [(a)]
Total change in fair value during 2020 of contracts recorded in result of operations	(203)
Reclassification to realized at settlement of contracts recorded in results of operations	469
Changes in allocated collateral	(513)
Net option premium paid	139
Option premium amortization	(104)
Upfront payments and amortizations[(b)]	73
Balance as of December 31, 2020	$ 729 [(a)]
Total change in fair value during 2021 of contracts recorded in result of operations	797
Reclassification to realized at settlement of contracts recorded in results of operations	(228)
Changes in allocated collateral	96
Net option premium paid	338
Option premium amortization	(125)
Upfront payments and amortizations[(b)]	15
Balance as of December 31, 2021	$ 1,622 [(a)]

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes derivative contracts acquired or sold through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following table presents maturity and source of fair value for mark-to-market commodity contract net assets (liabilities). The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of our total mark-to-market net assets (liabilities), net of allocated collateral. Second, the table shows the maturity, by year, of our commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 18 — Fair Value of Financial Assets and Liabilities of the Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

	Maturities Within						
	2022	2023	2024	2025	2026	2027 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$ 711	$ 66	$ 53	$ 43	$ 24	$ —	$ 897
Prices provided by external sources (Level 2)	442	436	(60)	1	—	—	819
Prices based on model or other valuation methods (Level 3)	37	(74)	23	5	(24)	(61)	(94)
Total	$ 1,190	$ 428	$ 16	$ 49	$ —	$ (61)	$ 1,622

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid/(received) from counterparties (and offset against mark-to-market assets and liabilities) of $512 million at December 31, 2021.

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for a detailed discussion of credit risk.

The following tables provide information on our credit exposure for all derivative instruments, NPNS, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the table below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, and commodity exchanges, which are discussed below.

Rating as of December 31, 2021	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 715	$ 176	$ 539	1	$ 106
Non-investment grade	13	—	13	—	—
No external ratings					
Internally rated—investment grade	111	—	111	—	—
Internally rated—non-investment grade	226	47	179	—	—
Total	$ 1,065	$ 223	$ 842	1	$ 106

(a) As of December 31, 2021, credit collateral held from counterparties where we had credit exposure included $163 million of cash and $60 million of letters of credit.

Rating as of December 31, 2021	Maturity of Credit Risk Exposure: Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 605	$ 62	$ 48	$ 715
Non-investment grade	13	—	—	13
No external ratings				
Internally rated—investment grade	111	—	—	111
Internally rated—non-investment grade	181	39	6	226
Total	$ 910	$ 101	$ 54	$ 1,065

Net Credit Exposure by Type of Counterparty	As of December 31, 2021
Financial institutions	$ 32
Investor-owned utilities, marketers, power producers	711
Energy cooperatives and municipalities	62
Other	37
Total	$ 842

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physical or financial contracts for the sale and purchase of electricity, natural gas, and other commodities. In accordance with the contracts and applicable law, if we are downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on our net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information regarding collateral requirements and Note 19 — Commitments and Contingencies of the Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

We transact output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on our financial statements. As market prices rise above or fall below contracted price levels, we are required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with us. To post collateral, we depend on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 7. Liquidity and Capital Resources — Credit Matters — Credit Facilities for additional information.

RTOs and ISOs

We participate in all, or some, of the established, wholesale spot energy markets that are administered by PJM, ISO-NE, NYISO, CAISO, MISO, SPP, AESO, OIESO, and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on our financial statements. See Note 3 — Regulatory Matters of the Notes to Consolidated Financial Statements for additional information on the February 2021 extreme cold weather event and Texas-based generating asset outages.

Exchange Traded Transactions

We enter into commodity transactions on NYMEX, ICE, NASDAQ, NGX, and the Nodal exchange ("the Exchanges"). The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on Exchanges are significantly collateralized and have limited counterparty credit risk.

Interest Rate and Foreign Exchange Risk

We use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. We may also utilize interest rate swaps to manage our interest rate exposure. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $2 million decrease in our pre-tax income for the year ended December 31, 2021. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, we utilize foreign currency derivatives, which are typically designated as economic hedges. See Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information.

Equity Price Risk

We maintain trust funds, as required by the NRC, to fund the costs of decommissioning our nuclear plants. Our NDT funds are reflected at fair value in the Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate us for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. We actively monitor the investment performance of the trust funds and periodically review asset allocations in accordance with our NDT fund investment policy. A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would result in a $892 million reduction in the fair value of the trust assets as of December 31, 2021. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Liquidity and Capital Resources section of ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed 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.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

We assessed the effectiveness of our internal control over financial reporting as of December 31, 2021. In making this assessment, we used the criteria in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, we concluded that, as of December 31, 2021, our internal control over financial reporting was effective.

February 25, 2022

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Constellation Energy Generation, LLC

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(ii), of Constellation Energy Generation, LLC (formerly known as Exelon Generation Company, LLC) and its subsidiaries (the “Company”) (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 Company as of 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 accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated 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 Company 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 of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company 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 Company'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 consolidated 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 consolidated 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Annual Nuclear Decommissioning Asset Retirement Obligations (AROs) Assessment

As described in Notes 1 and 10 to the consolidated financial statements, the Company has a legal obligation to decommission its nuclear generation stations following permanent cessation of operations. To estimate its decommissioning obligations related to its nuclear generating stations for financial accounting and reporting purposes, management uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. Management updates its AROs annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. As of December 31, 2021, the nuclear decommissioning AROs were $12.7 billion.

The principal considerations for our determination that performing procedures relating to the Company's annual nuclear decommissioning AROs assessment is a critical audit matter are the significant judgment by management when estimating its decommissioning obligations; this in turn led to a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the reasonableness of management's discounted cash flow model and significant assumptions related to decommissioning cost studies. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's development of the inputs, assumptions, and model used in management's AROs assessment. These procedures also included, among others, testing management's process for estimating the decommissioning obligations by evaluating the appropriateness of the discounted cash flow model, testing the completeness and accuracy of data used by management, and evaluating the reasonableness of management's significant assumptions related to decommissioning cost studies. Professionals with specialized skill and knowledge were used to assist in evaluating the results of decommissioning cost studies.

Impairment Assessment of Long-Lived Generation Assets

As described in Notes 1, 8, and 12 to the consolidated financial statements, the Company evaluates the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, or plans to dispose of a long-lived asset significantly before the end of its useful life. Management determines if long-lived assets or asset groups are potentially impaired by comparing the undiscounted expected future cash flows to the carrying value when indicators of impairment exist. When the undiscounted cash flow analysis indicates a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value analysis is primarily based on the income approach using significant unobservable inputs including revenue and generation forecasts, projected capital and maintenance expenditures, and discount rates. As of December 31, 2021, the total carrying value of long-lived generation assets subject to this assessment was $19.6 billion.

The principal considerations for our determination that performing procedures relating to the Company's impairment assessment of long-lived generation assets is a critical audit matter are the significant judgment by management in assessing the recoverability and estimating the fair value of these long-lived generation assets or asset groups; this in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating the reasonableness of management's significant assumptions related to revenue and generation forecasts. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's development of the inputs, assumptions, and model used to assess the recoverability and estimate the fair value of the Company's long-lived generation assets or asset groups. These procedures also included, among others, testing management's process for developing the expected future cash flows for the long-lived generation assets or asset groups by evaluating the appropriateness of the future cash flow model, testing the completeness and accuracy of the data used by management, and evaluating the reasonableness of management's significant assumptions related to revenue and generation forecasts. Evaluating the reasonableness of the revenue and generation forecasts involved considering whether the forecasts were consistent with future commodity prices and external market data. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of the revenue forecasts.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 25, 2022

We have served as the Company's auditor since 2001.

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2021	2020	2019
Operating revenues			
Operating revenues	$ 18,461	$ 16,392	$ 17,752
Operating revenues from affiliates	1,188	1,211	1,172
Total operating revenues	19,649	17,603	18,924
Operating expenses			
Purchased power and fuel	12,157	9,592	10,849
Purchased power and fuel from affiliates	6	(7)	7
Operating and maintenance	3,934	4,613	4,131
Operating and maintenance from affiliates	621	555	587
Depreciation and amortization	3,003	2,123	1,535
Taxes other than income taxes	475	482	519
Total operating expenses	20,196	17,358	17,628
Gain on sales of assets and businesses	201	11	27
Operating (loss) income	(346)	256	1,323
Other income and (deductions)			
Interest expense, net	(282)	(328)	(394)
Interest expense to affiliates	(15)	(29)	(35)
Other, net	795	937	1,023
Total other income and (deductions)	498	580	594
Income before income taxes	152	836	1,917
Income taxes	225	249	516
Equity in losses of unconsolidated affiliates	(10)	(8)	(184)
Net (loss) income	(83)	579	1,217
Net income (loss) attributable to noncontrolling interests	122	(10)	92
Net (loss) income attributable to membership interest	$ (205)	$ 589	$ 1,125
Comprehensive (loss) income, net of income taxes			
Net (loss) income	$ (83)	$ 579	$ 1,217
Other comprehensive (loss) income, net of income taxes			
Unrealized loss on cash flow hedges	(1)	(2)	—
Unrealized gain on investments in unconsolidated affiliates	—	—	1
Unrealized gain on foreign currency translation	—	4	6
Other comprehensive (loss) income, net of income taxes	(1)	2	7
Comprehensive (loss) income	(84)	581	1,224
Comprehensive income (loss) attributable to noncontrolling interests	122	(10)	93
Comprehensive (loss) income attributable to membership interest	$ (206)	$ 591	$ 1,131

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2021	2020	2019
Cash flows from operating activities			
Net (loss) income	$ (83)	$ 579	$ 1,217
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	4,540	3,636	3,063
Asset impairments	545	563	201
Gain on sales of assets and businesses	(201)	(11)	(27)
Deferred income taxes and amortization of investment tax credits	(205)	78	361
Net fair value changes related to derivatives	(568)	(270)	228
Net realized and unrealized gains on NDT funds	(586)	(461)	(663)
Net unrealized (losses) gains on equity investments	160	(186)	—
Other non-cash operating activities	(605)	18	(124)
Changes in assets and liabilities:			
Accounts receivable	(616)	1,125	(186)
Receivables from and payables to affiliates, net	14	24	(52)
Inventories	(68)	(77)	(47)
Accounts payable and accrued expenses	346	(343)	(248)
Option premiums paid, net	(338)	(139)	(29)
Collateral (posted) received , net	(130)	479	(481)
Income taxes	256	186	302
Pension and non-pension postretirement benefit contributions	(259)	(255)	(175)
Other assets and liabilities	(3,540)	(4,362)	(467)
Net cash flows (used in) provided by operating activities	(1,338)	584	2,873
Cash flows from investing activities			
Capital expenditures	(1,329)	(1,747)	(1,845)
Proceeds from NDT fund sales	6,532	3,341	10,051
Investment in NDT funds	(6,673)	(3,464)	(10,087)
Collection of DPP	3,902	3,771	—
Proceeds from sales of assets and businesses	878	46	52
Acquisitions of assets and businesses, net	—	—	(41)
Other investing activities	(28)	11	3
Net cash flows provided by (used in) investing activities	3,282	1,958	(1,867)
Cash flows from financing activities			
Changes in short-term borrowings	362	20	320
Proceeds from short-term borrowings with maturities greater than 90 days	880	500	—
Issuance of long-term debt	152	3,155	42
Retirement of long-term debt	(105)	(4,334)	(813)
Retirement of long-term debt to affiliate	—	(550)	—
Changes in money pool with Exelon	(285)	285	(100)
Acquisition of CENG noncontrolling interest	(885)	—	—
Distributions to member	(1,832)	(1,734)	(899)
Contributions from member	64	64	41
Other financing activities	(46)	(70)	(51)
Net cash flows used in financing activities	(1,695)	(2,664)	(1,460)
Increase (decrease) in cash, restricted cash, and cash equivalents	249	(122)	(454)
Cash, restricted cash, and cash equivalents at beginning of period	327	449	903
Cash, restricted cash, and cash equivalents at end of period	$ 576	$ 327	$ 449
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 96	$ (88)	$ (34)
Increase in DPP	3,652	4,441	—
Increase in PP&E related to ARO update	618	850	959

See the Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets

	December 31,			
(In millions)	2021		2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	504	$	226
Restricted cash and cash equivalents		72		89
Accounts receivable				
Customer accounts receivable	1,724		1,330	
Customer allowance for credit losses	(55)		(32)	
Customer accounts receivable, net		1,669		1,298
Other accounts receivable	597		352	
Other allowance for credit losses	(5)		—	
Other accounts receivable, net		592		352
Mark-to-market derivative assets		2,169		644
Receivables from affiliates		160		153
Inventories, net				
Fossil fuel and emission allowances		284		233
Materials and supplies		1,004		978
Renewable energy credits		520		621
Assets held for sale		13		958
Other		994		1,395
Total current assets		7,981		6,947
Property, plant, and equipment (net of accumulated depreciation and amortization of $15,873 and $13,370 as of December 31, 2021 and 2020, respectively)		19,612		22,214
Deferred debits and other assets				
Nuclear decommissioning trust funds		15,938		14,464
Investments		174		184
Mark-to-market derivative assets		949		555
Prepaid pension asset		1,683		1,558
Deferred income taxes		32		6
Other		1,717		2,166
Total deferred debits and other assets		20,493		18,933
Total assets[(a)]	$	48,086	$	48,094

See the Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2021	December 31, 2020
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 2,082	$ 840
Long-term debt due within one year	1,220	197
Accounts payable	1,757	1,253
Accrued expenses	737	788
Payables to affiliates	131	107
Borrowings from money pool with Exelon	—	285
Mark-to-market derivative liabilities	981	262
Renewable energy credit obligation	777	661
Liabilities held for sale	3	375
Other	308	451
Total current liabilities	7,996	5,219
Long-term debt	4,575	5,566
Long-term debt to affiliates	319	324
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,703	3,656
Asset retirement obligations	12,819	12,054
Non-pension postretirement benefit obligations	847	858
Spent nuclear fuel obligation	1,210	1,208
Payables to affiliates	3,357	3,017
Mark-to-market derivative liabilities	513	205
Other	1,133	1,311
Total deferred credits and other liabilities	23,582	22,309
Total liabilities[(a)]	36,472	33,418
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	10,482	9,624
Undistributed earnings	768	2,805
Accumulated other comprehensive loss, net	(31)	(30)
Total member's equity	11,219	12,399
Noncontrolling interests	395	2,277
Total equity	11,614	14,676
Total liabilities and equity	$ 48,086	$ 48,094

(a) Our consolidated assets include $2,549 million and $10,182 million as of December 31, 2021 and 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,077 million and $3,572 million as of December 31, 2021 and 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 21–Variable Interest Entities for additional information.

See the Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2018	$ 9,518	$ 3,724	$ (38)	$ 2,304	$ 15,508
Net income	—	1,125	—	92	1,217
Sale of noncontrolling interests	7	—	—	—	7
Changes in equity of noncontrolling interests	—	—	—	(48)	(48)
Distributions to member	—	(899)	—	—	(899)
Contributions from member	41	—	—	—	41
Other comprehensive income (loss), net of income taxes	—	—	6	(2)	4
Balance, December 31, 2019	$ 9,566	$ 3,950	$ (32)	$ 2,346	$ 15,830
Net income (loss)	—	589	—	(10)	579
Sale of noncontrolling interests	3	—	—	—	3
Changes in equity of noncontrolling interests	—	—	—	(59)	(59)
Distribution to member of deferred taxes associated with net retirement benefit obligation	(9)	—	—	—	(9)
Distributions to member	—	(1,734)	—	—	(1,734)
Contributions from member	64	—	—	—	64
Other comprehensive income, net of income taxes	—	—	2	—	2
Balance, December 31, 2020	$ 9,624	$ 2,805	$ (30)	$ 2,277	$ 14,676
Net (loss) income	—	(205)	—	122	(83)
Changes in equity of noncontrolling interests	—	—	—	(37)	(37)
Acquisition of CENG noncontrolling interest	1,080	—	—	(1,965)	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	(288)	—	—	—	(288)
Distributions to member	—	(1,832)	—	—	(1,832)
Contributions from member	64	—	—	—	64
Acquisition of other noncontrolling interest	2	—	—	(2)	—
Other comprehensive loss, net of income taxes	—	—	(1)	—	(1)
Balance, December 31, 2021	$ 10,482	$ 768	$ (31)	$ 395	$ 11,614

See the Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements
(Dollars in millions, unless otherwise noted)

1. Significant Accounting Policies

Description of Business

We are a supplier of clean energy. Our generating capacity consists of nuclear, wind, solar, natural gas and hydroelectric assets. Through our integrated business operations, we sell electricity, natural gas, and other energy related products and sustainable solutions to various types of customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets across multiple geographic regions. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions.

Basis of Presentation

On February 21, 2021, the board of directors of Exelon authorized management to pursue a plan to separate its competitive generation and customer-facing energy businesses, conducted through Constellation Energy Generation, LLC ("Constellation", formerly Exelon Generation Company, LLC) and its subsidiaries, into an independent, publicly-traded company. CEG Parent, a direct, wholly owned subsidiary of Exelon, was newly formed for the purpose of separation and had not engaged in any business activities nor had any assets or liabilities prior to the separation. On February 1, 2022, Exelon completed the separation by distributing all the outstanding shares of CEG Parent's common stock, on a pro rata basis to the holders of Exelon's common stock, with CEG Parent holding all the interests in Constellation previously held by Exelon. See Note 24 — Separation from Exelon for additional information.

As an individual registrant, Constellation has historically filed consolidated financial statements to reflect its financial position and operating results as a stand-alone, wholly owned subsidiary of Exelon. The accompanying Consolidated Financial Statements of Constellation have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC. The Consolidated Financial Statements include the accounts of our subsidiaries and all intercompany transactions have been eliminated. Unless otherwise indicated or the context otherwise requires, references herein to the terms "we," "us," and "our" refer to Constellation.

We own 100% of our significant consolidated subsidiaries, either directly or indirectly, except for certain consolidated VIEs, including CRP, of which we hold a 51% interest. The remaining interests in the consolidated VIEs are included in noncontrolling interests on the Consolidated Balance Sheets. See Note 21 — Variable Interest Entities for additional information on consolidated VIEs.

We consolidate the accounts of entities in which we have a controlling financial interest, after the elimination of intercompany transactions. Where we do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or accounting for investments in equity securities with or without readily determinable fair value is applied. We apply proportionate consolidation when we have an undivided interest in an asset and are proportionately liable for our share of each liability associated with the asset. We proportionately consolidate our undivided ownership interest in jointly owned electric plants. Under proportionate consolidation, we separately record our proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. We apply equity method accounting when we have a significant influence over an investee through an ownership in equity, which generally approximates a 20% to 50% voting interest.

We apply equity method accounting to certain investments and joint ventures. Under equity method accounting, we report our interest in the entity as an investment and our percentage share of the earnings from the entity as single line items in our financial statements. We use accounting for investments in equity securities with or without readily determinable fair values if we lack a significant influence, which generally results when we hold less than 20% of the common stock of an entity. Under accounting for investments in equity securities with readily determinable fair values, the investments are reported based on quoted prices in active markets and realized and unrealized gains and losses are included in earnings. Under accounting for investments in equity securities without readily determinable fair values, the investments are reported at cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment, and changes in measurement are reported in earnings.

COVID-19

We have taken steps to mitigate the potential risks posed by the global outbreak (pandemic) of the 2019 novel coronavirus (COVID-19). We provide a critical service to our customers and have taken measures to keep employees who operate the business safe and minimize unnecessary risk of exposure to the virus, including extra precautions for employees who work in the field. We have implemented work from home policies where appropriate and imposed travel limitations on employees.

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. As of December 31, 2021 and 2020, and through the date of this report, management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to the allowance for credit losses and the carrying value of other long-lived assets, in context with the information reasonably available to us and the unknown future impacts of COVID-19. Our future assessment of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts in the consolidated financial statements in future reporting periods.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and OPEB plans, inventory reserves, allowance for credit losses, long-lived asset impairment assessments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Revenues

Operating Revenues. Our operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of energy commodities and related products and services and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. We recognize revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that we expect to be entitled to in exchange for those goods or services. Our primary source of revenue includes competitive sales of power, natural gas, and other energy-related products and services. At the end of each reporting period, we accrue an estimate for the unbilled amount of energy delivered or services provided to customers.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. See Note 16 — Derivative Financial Instruments for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. We collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees, that are levied by state or local governments on the sale or distribution of electricity and natural gas. Some of these taxes are imposed on the customer, but paid by us, while others are imposed on us. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on us, such as gross receipts taxes, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 22 — Supplemental Financial Information for the taxes that are presented on a gross basis.

Leases

We recognize a ROU asset and lease liability for operating leases with a term of greater than one year. Operating lease ROU assets are included in Other deferred debits and other assets and operating lease liabilities are included in Other current liabilities and Other deferred credits and other liabilities on the Consolidated

Balance Sheets. The ROU asset is measured as the sum of (1) the present value of all remaining fixed and in-substance fixed payments using the rate implicit in the lease whenever that is readily determinable or our incremental borrowing rate, (2) any lease payments made at or before the commencement date (less any lease incentives received) and (3) any initial direct costs incurred. The lease liability is measured the same as the ROU asset, but excludes any payments made before the commencement date and initial direct costs incurred. Lease terms include options to extend or terminate the lease if it is reasonably certain they will be exercised. We include non-lease components for most asset classes, which are service-related costs that are not integral to the use of the asset, in the measurement of the ROU asset and lease liability.

Expense for operating leases and leases with a term of one year or less is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the derivation of benefit from use of the leased property. Variable lease payments are recognized in the period in which the related obligation is incurred and consist primarily of payments for purchases of electricity under contracted generation that are based on the electricity produced by those generating assets. Operating lease expense and variable lease payments are recorded to Purchased power and fuel expense for contracted generation or Operating and maintenance expense for all other lease agreements in the Consolidated Statements of Operations and Comprehensive Income.

Income from operating leases, including subleases, is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the pattern in which income is earned over the term of the lease. Variable lease payments are recognized in the period in which the related obligation is performed and consist primarily of payments received from sales of electricity under contracted generation that are based on the electricity produced by those generating assets. Operating lease income and variable lease payments are recorded to Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

Our operating leases consist primarily of contracted generation, real estate including office buildings, and vehicles and equipment. We generally account for contracted generation in which the generating asset is not renewable as a lease if the customer has dispatch rights and obtains substantially all the economic benefits. We generally do not account for contracted generation in which the generating asset is renewable as a lease if the customer does not design the generating asset. We account for land right arrangements that provide for exclusive use as leases while shared use land arrangements are generally not leases.

See Note 11 — Leases for additional information.

Income Taxes

Deferred federal and state income taxes are recorded on significant temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred in the Consolidated Balance Sheets and are recognized in book income over the life of the related property. We account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. We recognize accrued interest related to unrecognized tax benefits in Interest expense, net or Other, net (interest income) and recognize penalties related to unrecognized tax benefits in Other, net in the Consolidated Statements of Operations and Comprehensive Income.

Cash and Cash Equivalents

We consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2021 and 2020, restricted cash and cash equivalents primarily represented the project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities. See Note 17 — Debt and Credit Agreements and Note 22 — Supplemental Financial Information for additional information.

Allowance for Credit Losses on Accounts Receivables

The allowance for credit losses reflects our best estimate of losses on the customers' accounts receivable balances based on historical experience, current information, and reasonable and supportable forecasts.

The allowance for credit losses for our retail customers is based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current conditions and forward-looking information such as industry trends, macroeconomic factors, changes in the regulatory environment, external credit ratings, publicly available news, payment status, payment history, and the exercise of collateral calls. The allowance for credit losses for our wholesale customers is developed using a credit monitoring process, like that used for retail customers. When a wholesale customer's risk characteristics are no longer aligned with the pooled population, we use specific identification to develop an allowance for credit losses. Adjustments to the allowance for credit losses are recorded in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

We have certain non-customer receivables in Other deferred debits and other assets which primarily are with governmental agencies and other high-quality counterparties with no history of default. As such, the allowance for credit losses related to these receivables is not material. We monitor these balances and will record an allowance if there are indicators of a decline in credit quality.

Variable Interest Entities

We account for our investments in and arrangements with VIEs based on the following specific requirements:

- qualitative assessment of factors determinant in whether we have a controlling financial interest,
- ongoing reconsideration of this assessment, and
- where we consolidate a VIE (as primary beneficiary), disclosure of (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 21 — Variable Interest Entities for additional information.

Inventories

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Natural gas, oil, materials and supplies, and emissions allowances are generally included in inventory when purchased. Natural gas, oil, and emissions allowances are expensed to Purchased power and fuel expense when used or sold. Materials and supplies generally include items utilized within our generating plants and are expensed to Operating and maintenance or capitalized to Property, plant and equipment, as appropriate, when installed or used.

Debt and Equity Security Investments

Debt Security Investments. Debt securities are reported at fair value and classified as available-for-sale securities. Unrealized gains and losses, net of tax, are reported in Other Comprehensive Income.

Equity Security Investments without Readily Determinable Fair Values. We have certain equity securities without readily determinable fair values. We have elected to use the measurement alternative to measure these investments, defined as cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment. Changes in measurement are reported in Other, net in the Consolidated Statements of Operations and Comprehensive Income.

Equity Security Investments with Readily Determinable Fair Values. We have certain equity securities with readily determinable fair values. For equity securities held in NDT funds, realized and unrealized gains and losses, net of tax, on our NDT funds associated with the Regulatory Agreement Units are included in Noncurrent payables to affiliates. Realized and unrealized gains and losses, net of tax, on our NDT funds associated with the Non-Regulatory Agreement Units are included in earnings. Our NDT funds are classified as current or noncurrent assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. For all other equity securities with readily determinable fair values, realized and unrealized gains and losses are included in Other, net in the Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Fair Value of Financial Assets and Liabilities and Note 10 — Asset Retirement Obligations for additional information.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. When appropriate, original cost also includes capitalized interest. Costs associated with nuclear outages and planned major maintenance activities, are expensed to Operating and maintenance expense or capitalized to Property, plant, and equipment based on the nature of the activities in the period incurred. The cost of repairs and maintenance and minor replacements of property, is charged to Operating and maintenance expense as incurred.

Upon retirement, the cost of property is generally charged to accumulated depreciation in accordance with the composite and group methods of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to Operating and maintenance expense as incurred.

Capitalized Software. Certain costs, such as design, coding, and testing incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized in Property, plant and equipment in the Consolidated Balance Sheets. Similar costs incurred for cloud-based solutions treated as service arrangements are capitalized in Other current assets and Deferred debits and other assets in the Consolidated Balance Sheets. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life.

Capitalized Interest. During construction, we capitalize the costs of debt funds used to finance construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense. See Note 8 — Property, Plant, and Equipment, Note 9 — Jointly Owned Electric Utility Plant and Note 22 — Supplemental Financial Information for additional information.

Nuclear Fuel

The cost of nuclear fuel is capitalized in Property, plant and equipment and charged to Purchased power and fuel using the unit-of-production method. Any potential future SNF disposal fees will also be expensed through Purchased power and fuel expense. Additionally, certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 19 — Commitments and Contingencies for additional information regarding the cost of SNF storage and disposal.

Depreciation and Amortization

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimated service lives are based on a combination of depreciation studies, historical retirements, site licenses and management estimates of operating costs and expected future energy market conditions. See Note 7 — Early Plant Retirements for additional information on the impacts of early plant retirements, Note 8 — Property, Plant, and Equipment for additional information regarding depreciation, and Note 22 — Supplemental Financial Information for additional information regarding nuclear fuel and ARC.

Asset Retirement Obligations

We estimate and recognize a liability for our legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. We generally update our nuclear decommissioning ARO annually, unless circumstances warrant more frequent updates, based on our annual evaluation of cost escalation factors and probabilities assigned to the multiple outcome scenarios within our probability-weighted discounted cash flow models. Our multiple outcome scenarios are generally based on decommissioning cost studies which are updated, on a rotational basis, for each of our nuclear units at least every five years, unless circumstances warrant more frequent updates. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income for Non-Regulatory Agreement Units and through a decrease in noncurrent payables to affiliates for Regulatory Agreement Units. See Note 10 — Asset Retirement Obligations for additional information.

Guarantees

If necessary, we recognize a liability at the time of issuance of a guarantee for the fair value of the obligations we have undertaken by issuing the guarantee. The liability is reduced or eliminated as we are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 19 — Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. We regularly monitor and evaluate the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, or plans to dispose of a long-lived asset significantly before the end of its useful life. We determine if long-lived assets or asset groups are potentially impaired by comparing the undiscounted expected future cash flows to the carrying value when indicators of impairment exist. When the undiscounted cash flow analysis indicates a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. See Note 12 — Asset Impairments for additional information.

Equity Method Investments. We regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the entity in which we hold an investment recognizes an impairment loss, we would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt Security Investments. Declines in the fair value of debt security investments below the cost basis are reviewed to determine if such declines are other-than-temporary. If the decline is determined to be other-than-temporary, the amount of the impairment loss is included in earnings.

Equity Security Investments. Equity investments with readily determinable fair values are measured and recorded at fair value with any changes in fair value recorded in earnings. Investments in equity securities without readily determinable fair values are qualitatively assessed for impairment each reporting period. If it is determined that the equity security is impaired, an impairment loss will be recognized in earnings to the amount by which the security's carrying amount exceeds its fair value.

Derivative Financial Instruments

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including NPNS. For derivatives intended to serve as economic hedges, changes in fair value are recognized in earnings each period. Amounts classified in earnings are included in Operating revenue, Purchased power and fuel, Interest expense, or Other, net in the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. While most of the derivatives serve as economic hedges, there are also derivatives entered into for proprietary trading purposes, subject to our RMP, and changes in the fair value of those derivatives are recorded in revenue or expense in the Consolidated Statements of

Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing, or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

As part of the energy marketing business, we enter contracts to buy and sell energy to meet the requirements of our customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. NPNS are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as NPNS are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value. See Note 16 — Derivative Financial Instruments for additional information.

Retirement Benefits

Exelon sponsored defined benefit pension plans and OPEB plans as described in Note 15 — Retirement Benefits . The plan obligations and costs of providing benefits under these plans were measured as of December 31, 2021. We accounted for our participation in Exelon's pension and OPEB plans by applying multi-employer accounting. Exelon allocated costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan. We included the service cost and non-service cost components in Operating and maintenance expense and Property, plant, and equipment, net in the consolidated financial statements.

2. Mergers, Acquisitions, and Dispositions

CENG Put Option

Prior to August 6, 2021, we owned a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in our financial statements. See Note 21 — Variable Interest Entities for additional information.

On April 1, 2014, we entered into various agreements including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others with EDF. Under the amended LLC Operating Agreement, CENG made a $ 400 million special distribution to EDF and committed to make preferred distributions to us until we had received aggregate distributions of $400 million plus a return of 8.50% per annum.

Under the terms of the Put Option Agreement, EDF had the option to sell its 49.99% equity interest in CENG exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. On November 20, 2019, we received notice of EDF's intention to exercise the put option, and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. The transaction required approval by FERC and the NYPSC, which approvals were received on July 30, 2020 and April 15, 2021, respectively. On August 6, 2021, we entered into a settlement agreement pursuant to which we purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF's share of the outstanding balance of the preferred distribution payable to us by CENG. The difference between the net purchase price and EDF's noncontrolling interest as of August 6, 2021 was recorded to Membership interest in the Consolidated Balance Sheet. As a result of the transaction, we also recorded deferred tax liabilities of $288 million in Membership interest in the Consolidated Balance Sheet. See Note 14 — Income Taxes for additional information.

(Dollars in millions, unless otherwise noted)

The following table summarizes the effects of the changes in our ownership interest in CENG in Members Equity:

	For the Year Ended December 31, 2021	
Net loss attributable to membership interest	$	(205)
Pre-tax increase in membership interest for purchase of EDF's 49.99% equity interest[(a)]		1,080
Decrease in membership interest due to deferred tax liabilities resulting from purchase of EDF's 49.99% equity interest[(a)]		(288)
Change from net loss attributable to membership interest and transfers from noncontrolling interest	$	587

(a) Represents non-cash activity in the consolidated financial statements.

Agreement for Sale of Our Solar Business

On December 8, 2020, we entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of our solar business, including 360 MW of generation in operation or under construction across more than 600 sites across the United States. We will retain certain solar assets not included in this agreement, primarily Antelope Valley.

Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions that were satisfied in the first quarter of 2021. The sale was completed on March 31, 2021 for a purchase price of $810 million. We received cash proceeds of $675 million, net of $125 million long-term debt assumed by the buyer and certain working capital and other post-closing adjustments. We recognized a pre-tax gain of $68 million which is included in Gain on sales of assets and businesses in the Consolidated Statement of Operations and Comprehensive Income.

See Note 17 — Debt and Credit Agreements for additional information on the SolGen nonrecourse debt included as part of the transaction.

Agreement for Sale of Our Biomass Facility

On April 28, 2021, we entered into a purchase agreement with ReGenerate, under which ReGenerate agreed to purchase our interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, we recorded a pre-tax impairment charge of $ 140 million in Operating and maintenance expense in the Consolidated Statement of Operations and Comprehensive Income. Completion of the transaction was subject to the satisfaction of various customary closing conditions that were satisfied in the second quarter of 2021. The sale was completed on June 30, 2021 for a net purchase price of $36 million.

Disposition of Oyster Creek

On July 31, 2018, we entered into an agreement with Holtec and its indirect wholly owned subsidiary, OCEP, for the sale and decommissioning of Oyster Creek located in Forked River, New Jersey, which permanently ceased generation operations on September 17, 2018. Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and a private letter ruling from the IRS, which were satisfied in the second quarter of 2019. The sale was completed on July 1, 2019. We recognized a loss on the sale in the third quarter of 2019, which was immaterial.

Under the terms of the transaction, we transferred to OCEP substantially all the assets associated with Oyster Creek, including assets held in NDT funds, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of the SNF until it is moved offsite. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to us upon the occurrence of specified events.

3. Regulatory Matters

The following matters below discuss the status of our material regulatory and legislative proceedings.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, the PUCT directed ERCOT to use an administrative price cap of $9,000 per MWh during firm load shedding events.

The estimated impact to our Net income for the year ended December 31, 2021 arising from these market and weather conditions was a reduction of approximately $800 million. The ultimate impact to our consolidated financial statements may be affected by a number of factors, including the impacts of customer and counterparty defaults and recoveries, any additional solutions to address the financial challenges caused by the event, and related litigation and contract disputes.

During February and March 2021, various parties with differing interests, including generators and retail providers, filed requests with the PUCT to void the PUCT's orders setting prices at $9,000 per MWh during firm load shedding events. Other requests were made for the PUCT to enforce its order and reduce prices for 33 hours between February 18 and February 19 after firm load shedding ceased, and to cap ancillary services at $9,000 per MWh. On March 2, 2021, a third-party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT's actions. We intervened in that appeal and filed our initial brief on June 2, 2021 and reply brief on November 5, 2021. On April 19, 2021, we filed a declaratory action and request for judicial review of the PUCT's orders setting prices at $9,000 per MWh in the District Court of Travis County, Texas. We subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third-party proceeding. On May 17, 2021, we amended our petition for declaratory action and request for judicial review pending in the District Court of Travis County, Texas. We cannot reasonably predict the outcome of these proceedings or the potential financial statement impact.

Due to the event, a number of ERCOT market participants experienced bankruptcies or defaulted on payments to ERCOT, resulting in approximately a $3.0 billion payment shortfall in collections, which is allocated to the remaining ERCOT market participants. As of December 31, 2021, we have recorded our estimated portion of this obligation, net of legislative solutions, of approximately $17 million on a discounted basis, which is to be paid over a term of 83 years. ERCOT rules historically have limited recovery of default from market participants to $2.5 million per month market-wide. In February 2021, the PUCT gave ERCOT discretion to disregard those rules, but ERCOT has declined to exercise that discretion as to the imposition of uplift charges. On March 8, 2021, a third-party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT's order to ERCOT in February 2021. We intervened in that appeal and filed an initial brief on July 7, 2021. The case has been stayed until March 3, 2022 to afford time for the PUCT to respond to ERCOT's November 18, 2021 request that the PUCT withdraw its February 2021 order. On May 7, 2021, we filed a declaratory action and request for judicial review of the PUCT's order in the District Court of Travis County, Texas. We subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third-party proceeding. We cannot reasonably predict the outcome of these proceedings or the potential financial statement impact.

Additionally, several legislative proposals were introduced in the Texas legislature during February and March 2021 concerning the amount, timing and allocation of recovery of the $3.0 billion shortfall, as well as recovery of other costs associated with the PUCT's directive to set prices at $9,000 per MWh. Two of these proposals were enacted into law in June 2021 and establish financing mechanisms that ERCOT and certain market participants can utilize to fund amounts owed to ERCOT. We participated in proceedings before the PUCT addressing the proposed allocation of the $2.1 billion in securitized funds for reliability and ancillary service charges over $9,000 per MWh. In September 2021, we entered into a settlement agreement and stipulation to resolve the allocation issues. The PUCT approved the settlement agreement and stipulation on October 13, 2021.

In addition, other legislative proposals were introduced in the Texas legislature during February and March 2021 addressing cold-weather preparation for power plants and natural gas production and transportation infrastructure and the market structure for reliability services. The Texas legislature addressed these proposals by enacting a bill with a broad set of market reforms that, among other things, directed the PUCT to establish weatherization standards for electric generators within six months of enactment and gave the PUCT authority to impose administrative penalties if the new proposed standards, once adopted, are not met. On October 21, 2021, the PUCT adopted a rule change requiring generators by December 1, 2021 to complete a number of specified winter readiness preparations and to submit to ERCOT a report describing and certifying the completion of those preparations. The PUCT described these requirements as the first phase of its actions with respect to winter preparedness, which we completed timely, and will be followed by a second phase consisting of a year-round set of weather preparedness standards to be informed by a weather study conducted by ERCOT and submitted to the PUCT on December 15, 2021.

The legislation also directs the PUCT to evaluate whether additional ancillary services are needed for reliability in the ERCOT power region to provide adequate incentives for dispatchable generation. Throughout 2021, we and others submitted various proposals to the PUCT with respect to a range of potential market reforms, including the implementation of additional ancillary service products as well as changes to the high system-wide offer cap and operating reserve demand curve, which remain pending. On December 2, 2021, the PUCT reduced ERCOT's high system-wide offer cap to $5,000 per MWh.

In February 2021, more than 70 local distribution companies (LDCs) and natural gas pipelines in multiple states throughout the mid-continent region, where we serve natural gas customers, issued operational flow orders (OFOs), curtailments or other limitations on natural gas transportation or use to manage the operational integrity of the applicable LDC or pipeline system. When in effect, gas transportation or use above these limitations is subject to significant penalties according to the applicable LDCs' and natural gas pipelines' tariffs. Gas transportation and supply in many states became restricted due to wells freezing and pipeline compression disruption, while demand was increasing due to the extreme cold temperatures, resulting in extremely high natural gas prices. Due to the extraordinary circumstances, many LDCs and natural gas pipelines have either voluntarily waived or have sought applicable regulatory approvals to waive the tariff penalties associated with the extreme weather event. During March 2021, three natural gas pipelines filed individual petitions with FERC requesting approval to waive OFO penalties. We also filed motions in March 2021 to intervene and filed comments in support of these FERC waiver requests. On March 25, 2021, FERC issued an order on one of the petitions approving a pipeline's request for a limited waiver of penalties for February 15, 2021. On April 23, 2021, we and several other entities filed a request at FERC for rehearing of this order which was denied on May 24, 2021. We and the other entities filed an appeal of the rehearing of the order with the U.S. Court of Appeals for the D.C. Circuit on July 21, 2021. Additionally, we and the other entities filed a complaint requesting that FERC expand the order to include additional days of the weather event in February, from February 16 through February 19, 2021. On October 21, 2021, FERC denied the complaint finding that a pipeline has the discretion whether to waive penalties under its tariff, and on December 6, 2021 the related D.C. Circuit petition for review was withdrawn. During April 2021, FERC issued orders on the remaining petitions approving the requests to waive the penalties. During May 2021, an LDC filed a motion with the Kansas Corporation Commission (KCC) requesting the KCC to grant a waiver from the tariff and allow the LDC to reduce the amounts assessed by permitting the removal of a multiplier from the penalty calculation. On January 20, 2022, a unanimous settlement was filed with the KCC that amended previously filed October 8, 2021 and November 30, 2021 nonunanimous settlements which, if approved, would resolve this matter. We cannot reasonably predict the outcome of the KCC proceeding.

Illinois Regulatory Matters

Clean Energy Law. On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorized the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. Our Byron, Dresden, and Braidwood nuclear plants located in Illinois participated in the CMC procurement process and were awarded contracts that commit each plant to operate through May 31, 2027. Pursuant to these contracts, ComEd will procure CMCs based upon the number of MWhs produced annually by each plant, subject to minimum performance requirements. The price to be paid for each CMC was established through a competitive bidding process that included consumer-protection measures that capped the maximum acceptable bid amount and reduces CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy, if applicable. The consumer protection measures contained in the new law will result in net payments to ComEd ratepayers if the energy index, the capacity price and applicable federal tax credits or subsidy exceed the CMC contract price. Regulatory or legal challenges regarding the validity or implementation of the Clean Energy Law are possible and we cannot reasonably predict the outcome of any such challenges.

See Note 7 – Early Plant Retirements for the impacts of the provisions above on the Illinois nuclear plants and the consolidated financial statements.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, we began recognizing revenue for the sale of New Jersey ZECs in the month they are generated. On March 19, 2021, a three-judge panel of the Superior Court of New Jersey Appellate Division unanimously affirmed the NJBPU's April 2019 order awarding ZECs for the first eligibility period. On April 8, 2021, New Jersey Rate Counsel filed a notice asking the New Jersey Supreme Court to hear the appeal of the Superior Court's order. On July 9, 2021, the New Jersey Supreme Court declined to hear the appeal. On October 1, 2020, we and PSEG filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). On April 27, 2021, the NJBPU approved the award of ZECs to Salem 1 and Salem 2 for the second eligibility period. On May 11, 2021, the New Jersey Rate Counsel appealed the April 27, 2021 decision to the Superior Court of New Jersey Appellate Division. Briefing on the appeal is expected to conclude in the first half of 2022. We cannot reasonably predict the outcome of this proceeding.

New England Regulatory Matters

Mystic Units 8 and 9 and Everett Marine Terminal Cost of Service Agreement. On March 29, 2018, we notified grid operator ISO-NE of our plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, we made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 and 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal we acquired in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, we and several other parties filed requests for rehearing of certain findings in the order. On July 15, 2021, FERC issued an order establishing the ROE to be used in the cost of service agreement for Mystic 8 and 9 at 9.33%. On August 16, 2021, we and several other parties filed requests for rehearing of certain aspects of the July 15, 2021 order. These requests were denied by operation of law; however, FERC indicated it would address the issues raised in the request in a future order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic's cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third-party gas sales during the term of the cost of service agreement. In addition, several parties filed protests to a compliance filing by us on September 15, 2020, taking issue with how gross plant in-service was calculated, and we filed an answer to the protests on October 21, 2020. On December 21, 2020, FERC issued an order on rehearing of the three July 17, 2020 orders, clarifying several cost of service provisions. Several parties appealed the December 21, 2020 order to the U.S. Court of Appeals for the D.C. Circuit and that appeal was consolidated with appeals of orders issued December 20, 2018 and July 17, 2020 in the Mystic proceeding. Briefs in support of their petitions for review were filed by us and several other parties on September 7, 2021. Briefing concluded in February 2022 and oral argument is scheduled to begin in May 2022.

On February 25, 2021, Mystic made its filing to comply with the December 21, 2020 order. On April 26, 2021, FERC rejected Mystic's language and directed another compliance filing relating to the claw back provision language, which only applies if Mystic 8 and 9 were to continue operation after the conclusion of the cost-of-service period. FERC's April 26, 2021 order also accepted in part and rejected in part Mystic's September 15, 2020 compliance filing. It directed a further compliance filing in 60 days consistent with the information provided in Mystic's October 21, 2020 answer to protests, which Mystic filed on June 2, 2021 and FERC accepted on July 29, 2021. On August 16, 2021, Mystic made a compliance filing, reflecting changes to the cost of service agreement to comply with the July 15, 2021 order on ROE.

On August 25, 2020, a group of New England generators filed a complaint against us seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby we would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On April 15, 2021 FERC dismissed the complaint.

On February 16, 2021, we filed an unopposed motion to voluntarily dismiss an appeal filed with the U.S. Court of Appeals for the D.C. Circuit stemming from a June 2020 complaint filed with FERC against ISO-NE over failures to follow its tariff in evaluating Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period, which was granted on February 18, 2021.

See Note 7 — Early Plant Retirements and Note 12 — Asset Impairments for additional information on the impacts of our August 2020 decision to retire Mystic Units 8 and 9 upon expiration of the cost of service agreement.

Federal Regulatory Matters

PJM and NYISO MOPR Proceedings. PJM and NYISO capacity markets include a MOPR. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a state government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources. Currently, the MOPR in NYISO applies only to certain resources in downstate New York.

For our nuclear facilities in PJM and NYISO that are currently receiving state-supported compensation for carbon-free attributes, an expanded MOPR would require exclusion of such compensation when bidding into future capacity auctions, resulting in an increased risk of these facilities not receiving capacity revenues in future auctions.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. This greatly expanded the breadth and scope of PJM's MOPR, which became effective as of PJM's capacity auction for the 2022-23 planning year. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources.

FERC provided no new mechanism for accommodating state-supported resources other than the existing FRR mechanism (under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone). In response to FERC's order, PJM submitted a compliance filing on March 18, 2020 wherein PJM proposed tariff language interpreting and implementing FERC's directives, and proposed a schedule for resuming capacity auctions that is contingent on the timing of FERC's action on the compliance filing.

On April 16, 2020, FERC issued an order largely denying most requests for rehearing of FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing which PJM submitted on June 1, 2020.

A number of parties, including us, have filed petitions for review of FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Seventh Circuit.

As a result, the MOPR applied in the capacity auction for the 2022-23 planning year to our owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES, and the New Jersey ZEC program. The MOPR prevented Quad Cities from clearing in that capacity auction.

At the direction of the PJM Board of Managers, PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. PJM filed related tariff revisions at FERC on July 30, 2021 and, on September 29, 2021, PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR will no longer apply to any of our owned or jointly owned nuclear plants. Requests for rehearing of FERC's notice establishing the effective date for PJM's proposed market reforms were filed in October 2021 and denied by operation of law on November 4, 2021. Several parties have filed petitions for review of FERC's orders in this proceeding, which remain pending before the Court of Appeals for the Third Circuit. We are strenuously opposing these appeals. We cannot reasonably predict the outcome of this proceeding.

On February 20, 2020, FERC issued an order rejecting requests to expand NYISO's version of the MOPR (referred to as buyer-side mitigation rules) beyond its current limited applicability to certain resources in downstate. However, on October 14, 2020, two natural gas-fired generators in New York filed a complaint at FERC seeking to expand the MOPR in NYISO to apply to all resources, new and existing, across the entire NYISO market. We are strenuously opposing expansion of FERC's MOPR policies in the NYISO market. While it is too early in the proceeding to predict its outcome and there are significant differences between the NYISO and PJM markets that would justify a different result, if FERC applies the MOPR in NYISO broadly as requested in the complaint, our facilities in NYISO that are receiving ZEC compensation may be at increased risk of not clearing the capacity auction.

If our state-supported nuclear plants in PJM or NYISO are subjected to a MOPR or equivalent without compensation under an FRR or similar program, it could have a material adverse impact on our financial statements, which we cannot reasonably estimate at this time.

Operating License Renewals

Conowingo Hydroelectric Project. On August 29, 2012, we submitted an application to FERC for a new license for the Conowingo Hydroelectric Project (Conowingo). In connection with our efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) from MDE for Conowingo, we had been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 21, 2016, we and the U.S. Fish and Wildlife Service of the U.S. Department of the Interior executed a settlement agreement (DOI Settlement) resolving all fish passage issues between the parties.

On April 27, 2018, MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contained numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage.

On October 29, 2019, we and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. Pursuant to the Offer of Settlement, the parties submitted Proposed License Articles to FERC to be incorporated by FERC into the new license in accordance with FERC's discretionary authority under the Federal Power Act. Among the Proposed License Articles were modifications to river flows to improve aquatic habitat, eel passage improvements, and initiatives to support rare, threatened and endangered wildlife.

On March 19, 2021, FERC issued a new 50-year license for Conowingo, effective March 1, 2021. FERC adopted the Proposed License Articles into the new license, only making modifications it deemed necessary to allow FERC to enforce the Proposed License Articles. Consistent with the Offer of Settlement, FERC found that MDE waived its 401 Certification and pursuant to a separate agreement with MDE (MDE Settlement), we agreed to implement additional environmental protection, mitigation, and enhancement measures over the 50-year term of the new license. These measures address mussel restoration and other ecological and water quality matters, among other commitments. On April 19, 2021, a few environmental groups filed with FERC a petition for rehearing requesting that FERC reconsider the issuance of the new Conowingo license, which was denied by operation of law on May 20, 2021. On June 17, 2021, the petitioners appealed FERC's ruling to the U.S. Court of Appeals for the D.C. Circuit. On July 15, 2021, FERC issued an order addressing the arguments raised on rehearing, affirming the determinations of its March 19, 2021 order. We cannot predict the outcome of this proceeding.

The financial impact of the DOI and MDE Settlements and other anticipated license commitments are estimated to be $10 million to $12 million per year, on average, recognized over the new license term, including capital and operating costs. The actual timing and amount of the majority of these costs are not currently fixed and will vary from year to year throughout the life of the new license.

Peach Bottom Units 2 and 3. On March 6, 2020, the NRC approved a second 20-year license renewal for Peach Bottom Units 2 and 3. Peach Bottom Units 2 and 3 are now licensed to operate through 2053 and 2054, respectively. See Note 8 – Property, Plant, and Equipment for additional information regarding the estimated useful life and depreciation provisions for Peach Bottom.

On February 24, 2022, the NRC issued an order related to its review of our subsequent license renewal application for Peach Bottom. While the NRC had previously granted subsequent license renewal to the Peach Bottom units, the NRC was responding to a request for hearing that had not previously been adjudicated. In its decision, the NRC reversed itself and concluded that the previous environmental review required by the National Environmental Policy Act (NEPA) was incomplete because it did not adequately address environmental impacts resulting from extending the units' licenses by 20 years. As a result, the NRC directed its staff to change the expiration dates for the licenses back to 2033 and 2034, until the completion of the NEPA analysis. The NRC directed, however, that the subsequently renewed licenses themselves remain in effect. The NRC also stated that it fully expects that the staff will complete its update of the NEPA analysis before 2033. To date, the NRC staff has not yet taken action to cause amendment of the licenses. We are reviewing the decision and considering our options. We cannot reasonably predict the outcome of this proceeding however any change to the current license expiration dates could have a material adverse financial statement impact.

4. Revenue from Contracts with Customers

We recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that we expect to be entitled to in exchange for those goods or services. Our primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The performance obligations, revenue recognition, and payment terms associated with these sources of revenue are further discussed in the table below. There are no significant financing components for these sources of revenue.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, we have the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, we generally recognize revenue in the amount for which we have the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Revenue Source	Description	Performance Obligation	Timing of Revenue Recognition	Payment Terms
Competitive Power Sales	Sales of power and other energy-related commodities to wholesale and retail customers across multiple geographic regions through our customer-facing business.	Various, including the delivery of power (generally delivered over time) and other energy-related commodities such as capacity (generally delivered over time), ZECs, RECs or other ancillary services (generally delivered at a point in time).	Concurrently as power is generated for bundled power sale contracts. (a)	Within the month following delivery to the customer.
Competitive Natural Gas Sales	Sales of natural gas on a full requirement basis or for an agreed upon volume to commercial and residential customers.	Delivery of natural gas to the customer.	Over time as the natural gas is delivered and consumed by the customer.	Within the month following delivery to the customer.
Other Competitive Products and Services	Sales of other energy-related products and services such as long-term construction and installation of energy efficiency assets and new power generating facilities, primarily to commercial and industrial customers.	Construction and/or installation of the asset for the customer.	Revenues and associated costs are recognized throughout the contract term using an input method to measure progress towards completion.(b)	Within 30 or 45 days from the invoice date.

____
(a) Certain contracts may contain limits on the total amount of revenue we are able to collect over the entire term of the contract. In such cases, we estimate the total consideration expected to be received over the term of the contract net of the constraint and allocate the expected consideration to the performance obligations in the contract such that revenue is recognized ratably over the term of the entire contract as the performance obligations are satisfied.
(b) The method recognizes revenue based on the various inputs used to satisfy the performance obligation, such as costs incurred and total labor hours expended. The total amount of revenue that will be recognized is based on the agreed upon contractually-stated amount. The average contract term for these projects is approximately 18 months.

We incur incremental costs in order to execute certain retail power and gas sales contracts. These costs, which primarily relate to retail broker fees and sales commissions, are capitalized when incurred as contract acquisition costs and were not material as of December 31, 2021 and 2020.

Contract Balances

Contract Assets

We record contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before we have an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. We record contract assets and contract receivables in Other current assets and Customer accounts receivable, net, respectively, in the Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in the Consolidated Balance Sheets.

(Dollars in millions, unless otherwise noted)

		Contract Assets
Balance as of December 31, 2019	$	174
Amounts reclassified to receivables		(86)
Revenues recognized		68
Contract assets reclassified as held-for-sale		(12)
Balance as of December 31, 2020		144
Amounts reclassified to receivables		(59)
Revenues recognized		52
Amounts previously held-for-sale		12
Balance as of December 31, 2021	$	149

Contract Liabilities

We record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. We record contract liabilities in Other current liabilities and Other noncurrent liabilities in the Consolidated Balance Sheets. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans and the Illinois ZEC program that introduces a cap on the total consideration to be received by us.

The following table provides a rollforward of the contract liabilities reflected in the Consolidated Balance Sheets.

		Contract Liabilities
Balance as of December 31, 2018	$	42
Consideration received or due		287
Revenues recognized		(258)
Balance as of December 31, 2019		71
Consideration received or due		282
Revenues recognized		(266)
Contract liabilities reclassified as held-for-sale		(3)
Balance as of December 31, 2020		84
Consideration received or due		251
Revenues recognized		(263)
Amounts previously held-for-sale		3
Balance as of December 31, 2021	$	75

The following table reflects revenues recognized in the years ended December 31, 2021, 2020 and 2019, which were included in contract liabilities at December 31, 2020, 2019, and 2018, respectively:

	2021		2020		2019	
Revenues recognized	$	82	$	64	$	32

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2021. This disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years. This disclosure excludes our power and gas sales contracts as they contain variable volumes and/or variable pricing.

(Dollars in millions, unless otherwise noted)

	2022	2023	2024	2025	2026 and thereafter	Total
Remaining performance obligations	$ 350	$ 112	$ 45	$ 26	$ 73	$ 606

Revenue Disaggregation

We disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 5 — Segment Information for the presentation of revenue disaggregation.

5. Segment Information

Operating segments are determined based on information used by the CODM in deciding how to evaluate performance and allocate resources. We have five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as "Other Power Regions."

The basis for our reportable segments is the integrated management of our electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Our hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of our five reportable segments are as follows:

- **Mid-Atlantic** represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina.
- **Midwest** represents operations in the western half of PJM and the United States footprint of MISO, excluding MISO's Southern Region.
- **New York** represents operations within NYISO.
- **ERCOT** represents operations within Electric Reliability Council of Texas that covers a majority of the state of Texas.
- **Other Power Regions:**
  - **New England** represents operations within ISO-NE.
  - **South** represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM.
  - **West** represents operations in the WECC, which includes CAISO.
  - **Canada** represents operations across the entire country of Canada and includes AESO, OIESO, and the Canadian portion of MISO.

The CODM evaluates the performance of our electric business activities and allocates resources based on Revenues less Purchased Power and Fuel Expense (RNF). We believe this is a useful measurement of operational performance, although it is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Our operating revenues include all sales to third parties and affiliated sales to Exelon's utility subsidiaries. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for our owned generation and fuel costs associated with tolling agreements. The results of our other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to our overall operating revenues or results of operations. Further, our unrealized mark-to-market gains and losses on economic hedging activities and our amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. The CODM does not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

(Dollars in millions, unless otherwise noted)

The following tables disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. The disaggregation of revenues reflects our two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. The following tables also show the reconciliation of reportable segment revenues and RNF to our total revenues and RNF for the years ended December 31, 2021, 2020, and 2019.

	2021				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 4,381	$ 183	$ 4,564	$ 20	$ 4,584
Midwest	4,265	(205)	4,060	—	4,060
New York	1,633	(57)	1,576	(1)	1,575
ERCOT	896	276	1,172	9	1,181
Other Power Regions	3,937	981	4,918	(28)	4,890
Total Competitive Businesses Electric Revenues	$ 15,112	$ 1,178	$ 16,290	$ —	$ 16,290
Competitive Businesses Natural Gas Revenues	1,777	1,602	3,379	—	3,379
Competitive Businesses Other Revenues[c]	365	(385)	(20)	—	(20)
Total Consolidated Operating Revenues	$ 17,254	$ 2,395	$ 19,649	$ —	$ 19,649

	2020				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 4,785	$ (168)	$ 4,617	$ 28	$ 4,645
Midwest	3,717	312	4,029	(5)	4,024
New York	1,444	(12)	1,432	(1)	1,431
ERCOT	735	198	933	25	958
Other Power Regions	3,586	463	4,049	(47)	4,002
Total Competitive Businesses Electric Revenues	$ 14,267	$ 793	$ 15,060	$ —	$ 15,060
Competitive Businesses Natural Gas Revenues	1,283	720	2,003	—	2,003
Competitive Businesses Other Revenues[c]	355	185	540	—	540
Total Consolidated Operating Revenues	$ 15,905	$ 1,698	$ 17,603	$ —	$ 17,603

(Dollars in millions, unless otherwise noted)

	2019									
	Revenues from external customers[a]									
	Contracts with customers		Other[b]		Total		Intersegment Revenues		Total Revenues	
Mid-Atlantic	$	5,053	$	17	$	5,070	$	4	$	5,074
Midwest		4,095		232		4,327		(34)		4,293
New York		1,571		25		1,596		—		1,596
ERCOT		768		229		997		16		1,013
Other Power Regions		3,687		608		4,295		(49)		4,246
Total Competitive Businesses Electric Revenues	$	15,174	$	1,111	$	16,285	$	(63)	$	16,222
Competitive Businesses Natural Gas Revenues		1,446		702		2,148		62		2,210
Competitive Businesses Other Revenues[c]		440		51		491		1		492
Total Consolidated Operating Revenues	$	17,060	$	1,864	$	18,924	$	—	$	18,924

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to Exelon's utility subsidiaries.
(b) Includes revenues from derivatives and leases.
(c) Represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market losses of $633 million, gains of $110 million and losses of $4 million for the years ended December 31, 2021, 2020, and 2019, respectively, and the elimination of intersegment revenues.

	2021						2020						2019					
	RNF from external customers[a]		Intersegment RNF		Total RNF		RNF from external customers[a]		Intersegment RNF		Total RNF		RNF from external customers[a]		Intersegment RNF		Total RNF	
Mid-Atlantic	$	2,247	$	17	$	2,264	$	2,174	$	30	$	2,204	$	2,637	$	18	$	2,655
Midwest		2,717		—		2,717		2,902		—		2,902		2,994		(32)		2,962
New York		1,151		10		1,161		983		14		997		1,081		13		1,094
ERCOT		(668)		(157)		(825)		407		19		426		338		(30)		308
Other Power Regions		984		(93)		891		759		(94)		665		694		(74)		620
Total RNF for Reportable Segments	$	6,431	$	(223)	$	6,208	$	7,225	$	(31)	$	7,194	$	7,744	$	(105)	$	7,639
Other[b]		1,055		223		1,278		793		31		824		324		105		429
Total RNF	$	7,486	$	—	$	7,486	$	8,018	$	—	$	8,018	$	8,068	$	—	$	8,068

(a) Includes purchases and sales from/to third parties and affiliated sales to Exelon's utility subsidiaries.
(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:
- unrealized mark-to-market gains of $565 million and $295 million and losses of $215 million for the years ended December 31, 2021, 2020, and 2019, respectively;
- accelerated nuclear fuel amortization associated with the announced early plant retirements as discussed in Note 7 - Early Plant Retirements of $148 million, $60 million, and $13 million for the years ended December 31, 2021, 2020, and 2019, respectively; and
- the elimination of intersegment RNF.

(Dollars in millions, unless otherwise noted)

6. Accounts Receivable

Allowance for Credit Losses on Accounts Receivable

The following table presents the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Allowance for Credit Losses
Balance as of December 31, 2019	$ 80
Plus: Current period provision for expected credit losses	13
Less: Write-offs, net of recoveries[a]	5
Less: Sale of customer accounts receivable[b]	56
Balance as of December 31, 2020[c]	32
Plus: Current period provision for expected credit losses	30
Less: Write-offs, net of recoveries[a]	7
Balance as of December 31, 2021[c]	$ 55

(a) Recoveries were not material.
(b) See below for additional information on the sale of customer accounts receivable in the second quarter of 2020.
(c) Allowance for Credit Losses on Other Accounts Receivable was not material as of December 31, 2021 and 2020, respectively.

Unbilled Customer Revenue

We recorded $373 million and $258 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of December 31, 2021 and 2020, respectively.

Sales of Customer Accounts Receivable

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly owned by us, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility had a maximum funding limit of $750 million and was scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. The Facility was renewed on March 29, 2021. The Facility term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum funding limit was increased to $900 million. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in the consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets in the Consolidated Balance Sheets.

The Facility requires the balance of eligible receivables to be maintained at or above the balance of cash proceeds received from the Purchasers. To the extent the eligible receivables decrease below such balance, we are required to repay cash to the Purchasers. When eligible receivables exceed cash proceeds, we have the ability to increase the cash received up to the maximum funding limit. These cash inflows and outflows impact the DPP.

On April 8, 2020, we derecognized and transferred approximately $1.2 billion of receivables at fair value to the Purchasers in exchange for approximately $500 million in cash purchase price and $650 million of DPP.

During the first quarter of 2021, we received additional cash of $250 million from the Purchasers for the remaining available funding in the Facility.

Additionally, during the first quarter of 2021, we received cash of approximately $150 million from the Purchasers in connection with the increased funding limit at the time of the Facility renewal.

During the second quarter of 2021, we returned cash of $50 million to the Purchasers due to the eligible receivables decreasing temporarily. Subsequently, in the second quarter, we received cash of $50 million from the Purchasers as a result of an increase in the eligible receivable balance. The $50 million cash outflow and inflow is included in the Collection of DPP line in Cash flows from investing activities in the Consolidated Statement of Cash Flows.

(Dollars in millions, unless otherwise noted)

The following table summarizes the impact of the sale of certain receivables:

	As of December 31,	
	2021	2020
Derecognized receivables transferred at fair value	$ 1,265	$ 1,139
Cash proceeds received	900	500
DPP	365	639

	For the Years Ended December 31,	
	2021	2020
Loss on sale of receivables[(a)]	$ 36	$ 30

(a) Reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

	For the Years Ended December 31,	
	2021	2020
Proceeds from new transfers[(a)]	$ 6,095	$ 2,816
Cash collections received on DPP and reinvested in the Facility[(b)]	3,502	3,771
Cash collections reinvested in the Facility	9,597	6,587

(a) Customer accounts receivable sold into the Facility were $9,747 million and $6,608 million for the years ended December 31, 2021 and 2020, respectively.
(b) Does not include the $400 million in cash proceeds received from the Purchasers in the first quarter of 2021.

Our risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. We continue to service the receivables sold in exchange for a servicing fee. We did not record a servicing asset or liability as the servicing fees were immaterial.

We recognize the cash proceeds received upon sale in Net cash provided by operating activities in the Consolidated Statements of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities in the Consolidated Statements of Cash Flows.

See Note 18 — Fair Value of Financial Assets and Liabilities and Note 21 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables

We are required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include Exelon's utility subsidiaries. The following table presents the total receivables sold.

	For the Years Ended December 31,	
	2021	2020
Total receivables sold	$ 147	$ 824
Related party transactions:		
Receivables sold to Exelon's utility subsidiaries	23	252

7. Early Plant Retirements

We continuously evaluate factors that affect the current and expected economic value of our plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

On August 27, 2020, we announced our intention to permanently cease our operations at Byron in September 2021 and at Dresden in November 2021. Neither of these nuclear plants cleared in PJM's capacity auction for the 2022-2023 planning year held in May 2021. Our Braidwood and LaSalle nuclear plants in Illinois did clear in the capacity auction, but were also showing increased signs of economic distress.

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. Among other things, the Clean Energy Law authorized the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. Our Byron, Dresden, and Braidwood nuclear plants located in Illinois participated in the CMC procurement process and were awarded contracts that commit each plant to operate through May 31, 2027. See Note 3 — Regulatory Matters for additional information. Following enactment of the legislation, we announced on September 15, 2021, that we have reversed our previous decision to retire Byron and Dresden given the opportunity for additional revenue under the Clean Energy Law. In addition, we no longer consider the Braidwood or LaSalle nuclear plants to be at risk for premature retirement.

As a result of the decision to early retire Byron and Dresden, we recognized certain one-time charges in the third and fourth quarters of 2020 related to materials and supplies inventory reserve adjustments, employee-related costs including severance benefit costs, and construction work-in-progress impairments, among other items. In addition, there were ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date.

In the third quarter of 2021, we reversed $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in Operating and maintenance expense in the third and fourth quarters of 2020 associated with the early retirements. In addition, we updated the expected economic useful life for both facilities to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively, the end of the respective NRC operating license for each unit. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. See Note 10 — Asset Retirement Obligations for additional detail on changes to the nuclear decommissioning ARO balances resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden.

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, the third consecutive year that TMI failed to clear the PJM base residual capacity auction and on May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies, we announced that we would permanently cease generation operations at TMI. On September 20, 2019, TMI permanently ceased generation operations.

The total impact for the years ended December 31, 2021, 2020, and 2019 in the Consolidated Statements of Operations and Comprehensive Income resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden, and decision to early retire TMI is summarized in the table below.

(Dollars in millions, unless otherwise noted)

Income statement expense (pre-tax)	2021[(a)]	2020[(a)]	2019[(b)]
Depreciation and amortization			
Accelerated depreciation[(c)]	$ 1,805	$ 895	$ 216
Accelerated nuclear fuel amortization	148	60	13
Operating and maintenance			
One-time charges	(94)	255	—
Other charges[(d)]	9	34	(53)
Contractual offset[(e)]	(451)	(364)	—
Total	$ 1,417	$ 880	$ 176

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(a) Reflects expense for Byron and Dresden.
(b) Reflects expense for TMI.
(c) Includes the accelerated depreciation of plant assets including any ARC.
(d) For 2020 and 2019, reflects the net impacts associated with the remeasurement of the ARO. See Note 10 - Asset Retirement Obligations for additional information.
(e) Reflects contractual offset for ARO accretion, ARC depreciation, ARO remeasurement, and excludes any changes in earnings in the NDT funds. Decommissioning-related impacts were not offset for the Byron units starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset in the Consolidated Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activity result in a regulatory liability at ComEd. The offset resulted in an equal adjustment to the noncurrent payables to ComEd. See Note 10 - Asset Retirement Obligations for additional information.

We remain committed to continued operations for our other nuclear plants receiving state-supported payments under the Illinois ZES (Clinton and Quad Cities), New Jersey ZEC program (Salem), and the New York CES (FitzPatrick, Ginna, and Nine Mile Point) assuming the continued effectiveness of each program. To the extent each program does not operate as expected over the full term, each of these plants would be at heightened risk for early retirement, which could have a material impact in future financial statements. See Note 3 — Regulatory Matters for additional information on the New Jersey ZEC program.

We continue to work with stakeholders on state policy solutions to support continued operation of our nuclear fleet, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could have a material unfavorable impact on our future results of operations.

Other Generation

In March 2018, we notified ISO-NE of our plans to early retire, among other assets, the Mystic Generating Station's units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 - May 31, 2024. The agreement was approved by FERC in December 2018.

On June 10, 2020, we filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, we announced we will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 3 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, we recognized $22 million of one-time charges for the year ended December 31, 2020, related to materials and supplies inventory reserve adjustments, among other items. In addition, there are annual financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets. We recorded incremental Depreciation and amortization expense of $41 million and $26 million for the years ended December 31, 2021 and 2020, respectively. See Note 12 — Asset Impairments for impairment assessment considerations of the New England Asset Group.

(Dollars in millions, unless otherwise noted)

8. Property, Plant, and Equipment

The following table presents a summary of property, plant, and equipment by asset category as of December 31, 2021 and 2020:

Asset Category	December 31, 2021	December 31, 2020
Electric	$ 29,910	$ 29,724
Nuclear fuel[(a)]	5,166	5,399
Construction work in progress	399	450
Other property, plant, and equipment	10	11
Total property, plant, and equipment	35,485	35,584
Less: accumulated depreciation[(b)]	15,873	13,370
Property, plant, and equipment, net	$ 19,612	$ 22,214

(a) Includes nuclear fuel that is in the fabrication and installation phase of $859 million and $939 million as of December 31, 2021 and 2020, respectively.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,765 million and $2,774 million as of December 31, 2021 and 2020, respectively.

The following table presents the average service life for each asset category in number of years:

Asset Category	Average Service Life (years)
Electric	1-52
Nuclear fuel	1-8
Other property, plant, and equipment	1-10

Depreciation provisions are based on the estimated useful lives of the stations, which correspond with the term of the NRC operating licenses for each of our nuclear units. Beginning August 2020, Byron, Dresden, and Mystic depreciation provisions were based on their announced shutdown dates of September 2021, November 2021, and May 2024, respectively. On September 15, 2021, we updated the expected useful lives for Byron and Dresden to reflect the end of the available NRC operating license for each unit. See Note 3 — Regulatory Matters for additional information regarding license renewal and Note 7 — Early Plant Retirements for additional information on the impacts related to Byron, Dresden, and Mystic.

Annual depreciation rates for electric generation were 8.67%, 6.11%, and 4.35% for the years ended December 31, 2021, 2020, and 2019, respectively. Nuclear fuel amortization is charged to fuel expense using the unit-of-production method and not included in the annual depreciation rates.

Capitalized Interest

Capitalized interest was $15 million, $22 million, and $24 million for the years ended December 31, 2021, 2020, and 2019, respectively.

See Note 1 — Significant Accounting Policies for additional information regarding property, plant, and equipment policies.

(Dollars in millions, unless otherwise noted)

9. Jointly Owned Electric Utility Plant

Our material undivided ownership interests in jointly owned nuclear plants as of December 31, 2021 and 2020 were as follows:

	Nuclear Generation			
	Quad Cities	Peach Bottom	Salem	Nine Mile Point Unit 2
Operator	Constellation	Constellation	PSEG Nuclear	Constellation
Ownership interest	75.00 %	50.00 %	42.59 %	82.00 %
Our share as of December 31, 2021				
Plant in service	$ 1,211	$ 1,515	$ 756	$ 1,002
Accumulated depreciation	715	628	299	222
Construction work in progress	11	12	20	41
Our share as of December 31, 2020				
Plant in service	$ 1,188	$ 1,506	$ 717	$ 990
Accumulated depreciation	670	601	265	187
Construction work in progress	13	13	39	25

Our undivided ownership interests are financed with our funds and all operations are accounted for as if such participating interests were wholly owned facilities. Our share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses in the Consolidated Statements of Operations and Comprehensive Income.

10. Asset Retirement Obligations

Nuclear Decommissioning Asset Retirement Obligations

We have a legal obligation to decommission our nuclear power plants following the permanent cessation of operations. To estimate our decommissioning obligations related to our nuclear generating stations for financial accounting and reporting purposes, we use a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. We update our AROs annually, unless circumstances warrant more frequent updates, based on our review of updated cost studies and our annual evaluation of cost escalation factors and probabilities assigned to various scenarios. We began decommissioning the TMI nuclear plant upon permanently ceasing operations in 2019. See below section for decommissioning of Zion Station.

The financial statement impact for changes in the ARO, on an individual unit basis, due to the changes in and timing of estimated cash flows generally result in a corresponding change in the unit's ARC in Property, plant, and equipment in the Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement unit without any remaining ARC, the corresponding change is recorded as a decrease in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

The following table provides a rollforward of the nuclear decommissioning AROs reflected in the Consolidated Balance Sheets from December 31, 2019 to December 31, 2021:

	Nuclear Decommissioning AROs
Balance as of December 31, 2019	$ 10,504
Net increase due to changes in, and timing of, estimated future cash flows	1,022
Accretion expense	489
Costs incurred related to decommissioning plants	(93)
Balance as of December 31, 2020[(a)]	11,922
Net increase due to changes in, and timing of, estimated future cash flows	324
Accretion expense	503
Costs incurred related to decommissioning plants	(73)
Balance as of December 31, 2021[(a)]	$ 12,676

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(a) Includes $72 million and $80 million as the current portion of the ARO as of December 31, 2021 and 2020, respectively, which is included in Other current liabilities in the Consolidated Balance Sheets.

The net $324 million increase in the ARO during 2021 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year. These adjustments primarily include:

- An increase of approximately $550 million for updated cost escalation rates, primarily for labor and energy, and a decrease in discount rates.
- An increase of approximately $90 million due to revisions to assumed retirement dates for several nuclear plants.
- A net decrease of approximately $170 million was driven by updates to Byron and Dresden reflecting changes in assumed retirement dates and assumed methods of decommissioning as a result of the reversal of the decision to early retire the plants. See Note 7 — Early Plant Retirements for additional information.
- A net decrease of approximately $150 million due to lower estimated decommissioning costs resulting from the completion of updated cost studies for seven nuclear plants.

The 2021 ARO updates resulted in a decrease of $51 million in Operating and maintenance expense for the year ended December 31, 2021 in the Consolidated Statement of Operations and Comprehensive Income.

The net $1,022 million increase in the ARO during 2020 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year. These adjustments primarily include:

- A net increase of approximately $800 million was driven by updates to Byron and Dresden reflecting changes in assumed retirement dates and assumed methods of decommissioning as a result of the announcement to early retire these plants in 2021. Refer to Note 7 — Early Plant Retirements for additional information.
- An increase of approximately $360 million resulting from the change in the assumed DOE spent fuel acceptance date for disposal from 2030 to 2035.
- A decrease of approximately $220 million due to lower estimated decommissioning costs resulting from the completion of updated cost studies primarily for two nuclear plants.

The 2020 ARO updates resulted in an increase of $60 million in Operating and maintenance expense for the year ended December 31, 2020 in the Consolidated Statement of Operations and Comprehensive Income.

NDT Funds

NDT funds have been established for each of our nuclear units to satisfy our nuclear decommissioning obligations, as required by the NRC, and withdrawals from these funds for reasons other than to pay for decommissioning are restricted pursuant to NRC requirements until all decommissioning activities have been completed. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with our nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, through regulated rates for decommissioning the former PECO nuclear plants, and these collections are scheduled through the operating lives of these former PECO plants. The amounts collected from PECO customers are remitted to us and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment with the PAPUC proposing an annual recovery from customers of approximately $4 million. On August 8, 2017, the PAPUC approved the filing and the new rates became effective January 1, 2018.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, are generally required to be funded by us, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the former PECO nuclear plants where, through PECO, we have recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for those units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC that limits collection of amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by us. No recourse exists to collect additional amounts from utility customers for any of our other nuclear units.

With respect to the former ComEd and former PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with us related to the former PECO units. With respect to our other nuclear units, we retain any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, certain conditions pertaining to NDT funds apply that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities as defined in the agreement or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including SNF management and site restoration) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. We expect to comply with applicable regulations and timely commence and complete all required decommissioning activities.

We had NDT funds totaling $16,064 million and $14,599 million as of December 31, 2021 and 2020, respectively. The NDT funds also include $126 million and $134 million for the current portion of the NDT funds as of December 31, 2021 and 2020, respectively, which are included in Other current assets in the Consolidated Balance Sheets. See Note 22 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate our obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, decommissioning-related activities net of applicable taxes, including realized and unrealized gains and losses on the NDT funds, depreciation of the ARC, and accretion of the decommissioning obligation are generally offset in the Consolidated Statements of Operations and Comprehensive Income and are recorded as related party balances in the Consolidated Balance Sheets. For the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

For the former PECO units, given the symmetric settlement provisions that allow for continued recovery of decommissioning costs from PECO customers in the event of a shortfall and the obligation for us to ultimately return excess funds to PECO customers (on an aggregate basis for all seven units), decommissioning-related activities are generally offset in the Consolidated Statements of Operations and Comprehensive Income regardless of whether the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation. The offset of decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to noncurrent payables to or noncurrent receivables from affiliates. Any changes to the existing PECO regulatory agreements could impact our ability to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income, and the potential impact to our financial statements could be material.

For the former ComEd units, given no further recovery from ComEd customers is permitted and we retain an obligation to ultimately return any unused NDTs to ComEd customers (on a unit-by-unit basis), to the extent the related NDT investment balances are expected to exceed the total estimated decommissioning obligation for each unit, decommissioning-related activities are offset in the Consolidated Statements of Operations and Comprehensive Income which results in us recognizing a noncurrent payable to affiliates. However, given the asymmetric settlement provision that does not allow for continued recovery from ComEd customers in the event of a shortfall, recognition of a regulatory asset at ComEd is not permissible and accounting for decommissioning-related activities for that unit would not be offset, and the impact to the Consolidated Statements of Operations and Comprehensive Income could be material during such periods. During the second and third quarter of 2021, a pre-tax charge of $53 million and $140 million, respectively, was recorded in the Consolidated Statement of Operations and Comprehensive Income for decommissioning-related activities that were not offset for the Byron units due to contractual offset being temporarily suspended. With our September 15, 2021 reversal of the previous decision to retire Byron and the corresponding adjustment to the ARO for Byron discussed previously, we resumed contractual offset for Byron as of that date.

As of December 31, 2021, decommissioning-related activities for all of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are currently offset in the Consolidated Statements of Operations and Comprehensive Income.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in the Consolidated Statements of Operations and Comprehensive Income.

Zion Station Decommissioning

In 2010, we completed an ASA under which ZionSolutions assumed responsibility for decommissioning Zion Station and we transferred to ZionSolutions substantially all the Zion Station's assets, including the related NDT funds. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license back to us, we will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and complete all remaining decommissioning activities associated with the SNF dry storage facility.

We had retained our obligation for the SNF upon transfer of the NRC license to us as well as certain NDT assets to fund the obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by us. As of December 31, 2021, the ARO associated with Zion's SNF storage facility is $140 million and the NDT funds available to fund this obligation are $65 million.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations are calculated using an NRC methodology that is different from the ARO recorded in the Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements for radiological decommissioning calculated under the NRC methodology are greater than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires resolution of the shortfalls which could include further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation for radiological decommissioning costs using the NRC methodology at December 31, 2021 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by us to determine the ARO and to forecast the target growth in the NDT funds as of December 31, 2021 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site SNF maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain LLRW); (3) as applicable, the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under possible scenarios ranging from 10 to 70 years after the cessation of plant operations or the end of the current licensed operating life; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 4% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.5% to 6.3% (as compared to a historical 5-year annual average pre-tax return of approximately 10.2%).

We are required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of license expiration), based on values as of December 31, addressing our ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, we may be required to take steps, such as providing financial guarantees through surety bonds, letters of credit, or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, our cash flows and financial position may be significantly adversely affected.

We filed our biennial decommissioning funding status report with the NRC on February 24, 2021 for all units, including our shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for all units except for Byron Units 1 and 2. We filed an updated decommissioning funding status report for Byron Units 1 and 2 and Dresden Units 2 and 3 on September 28, 2021 based on their current license expiration dates consistent with our announcements regarding the continued operations of these units. This report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for Byron Units 1 and 2 and Dresden Units 2 and 3.

We will file the next decommissioning funding status report with the NRC by March 31, 2022. This report will also reflect the status of decommissioning funding assurance as of December 31, 2021 for shutdown units.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of our units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Impact of Separation from Exelon

Satisfying a condition precedent, on December 16, 2021, the NYPSC authorized our separation from Exelon and accepted the terms of a Joint Proposal that became binding upon closing of the separation on February 1, 2022. As part of the Joint Proposal, among other items, we have projected completion of radiological decommissioning and site restoration activities necessary to achieve a partial site release from the NRC (release of the site for unrestricted use, except for any on-site dry cask storage) within 20 years from the end of licensed life for each of our Ginna and FitzPatrick units and from the end of licensed life for the last of the NMP operating units. While there is flexibility under the Joint Proposal for decommissioning timing, we expect to increase the AROs associated with our New York nuclear plants during the first quarter of 2022 to reflect this scenario.

(Dollars in millions, unless otherwise noted)

The Joint Proposal also required a contribution of $15 million to the NDT for NMP Unit 2 in January 2022 and requires various financial assurance mechanisms through the duration of decommissioning and site restoration, including a minimum NDT balance for each unit, adjusted for specific stages of decommissioning, and a parent guaranty for site restoration costs updated annually as site restoration progresses, which must be replaced with a third-party surety bond or equivalent financial instrument in the event we fall below investment grade.

See Note 24 — Separation from Exelon for additional information.

Non-Nuclear Asset Retirement Obligations

We have AROs for plant closure costs associated with our natural gas, oil, and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations, and other decommissioning-related activities. See Note 1 — Significant Accounting Policies for additional information on the accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected in the Consolidated Balance Sheets from December 31, 2019 to December 31, 2021:

	Non-nuclear AROs
Balance as of December 31, 2019	$ 216
Net increase due to changes in, and timing of, estimated future cash flows	2
Development projects	1
Accretion expense	11
Asset divestitures	(4)
Payments	(4)
AROs reclassified to liabilities held for sale	(10)
Balance as of December 31, 2020	212
Net increase due to changes in, and timing of, estimated future cash flows	5
Accretion expense	11
Asset divestitures	(19)
Payments	(3)
AROs previously held for sale	10
Balance as of December 31, 2021	$ 216

11. Leases

Lessee

We have operating leases for which we are the lessee. The significant types of leases are contracted generation, real estate, and vehicles and equipment. The following table outlines other terms and conditions of the lease agreements as of December 31, 2021. We did not have material finance leases in 2021, 2020, or in 2019.

	Years
Remaining lease terms	1-34
Options to extend the term	1-30
Options to terminate within	1-2

(Dollars in millions, unless otherwise noted)

The components of operating lease costs were as follows:

	For the Years Ended December 31,		
	2021	2020	2019
Operating lease costs	$ 161	$ 194	$ 222
Variable lease costs	168	234	282
Short-term lease costs	—	2	19
Total lease costs[(a)]	$ 329	$ 430	$ 523

(a) Excludes $44 million of sublease income recorded for each of the years ended December 31, 2021, 2020, and 2019 respectively.

The following table provides additional information regarding the presentation of operating lease ROU assets and lease liabilities in the Consolidated Balance Sheets:

	As of December 31,	
	2021	2020
Operating lease ROU assets[(a)]		
Other deferred debits and other assets	$ 604	$ 726
Operating lease liabilities[(a)]		
Other current liabilities	72	132
Other deferred credits and other liabilities	705	775
Total operating lease liabilities	$ 777	$ 907

(a) The operating ROU assets and lease liabilities include $293 million and $429 million, respectively, related to contracted generation as of December 31, 2021, and $387 million and $528 million, respectively, as of December 31, 2020.

The weighted average remaining lease terms, in years, and the weighted average discount rates for operating leases were as follows:

	Weighted Average Remaining Lease Terms (in Years)	Weighted Average Discount Rates
As of December 31, 2021	10.1	5.0 %
As of December 31, 2020	10.5	4.9 %
As of December 31, 2019	10.6	4.8 %

Future minimum lease payments for operating leases as of December 31, 2021 were as follows:

Year	Future Minimum Lease payments
2022	$ 92
2023	99
2024	97
2025	99
2026	100
Remaining years	531
Total	1,018
Interest	241
Total operating lease liabilities	$ 777

(Dollars in millions, unless otherwise noted)

Cash paid for amounts included in the measurement of operating lease liabilities was $162 million, $204 million, and $206 million for the years ended December 31, 2021, 2020, and 2019, respectively.

ROU assets obtained in exchange for operating lease obligations were $(2) million, $3 million, and $14 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Lessor

We have operating leases for which we are the lessor. The significant types of leases are contracted generation and real estate. The following table outlines other terms and conditions of the lease agreements as of December 31, 2021.

	Years
Remaining lease terms	1-18
Options to extend the term	1-5

The components of lease income were as follows:

	For the Years Ended December 31,		
	2021	2020	2019
Operating lease income	$ 47	$ 47	$ 47
Variable lease income	261	282	258

Future minimum lease payments to be recovered under operating leases as of December 31, 2021 were as follows:

Year	Minimum lease payments to be recovered
2022	$ 45
2023	45
2024	45
2025	45
2026	45
Remaining years	137
Total	$ 362

12. Asset Impairments

We evaluate the carrying value of long-lived assets or asset groups for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, or plans to dispose of a long-lived asset significantly before the end of its useful life. We determine if long-lived assets or asset groups are potentially impaired by comparing the undiscounted expected future cash flows to the carrying value when indicators of impairment exist. When the undiscounted cash flow analysis indicates a long-lived asset or asset group may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value analysis is primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could potentially result in material future impairments of our long-lived assets.

New England Asset Group

In the third quarter of 2020, in conjunction with the retirement announcement of Mystic Units 8 and 9, we completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the estimated undiscounted future cash flows and fair value of the New England asset group were less than their carrying values. As a result, a pre-tax impairment charge of $500 million was recorded in the third quarter of 2020 in Operating and maintenance expense in the Consolidated Statement of Operations and Comprehensive Income. See Note 7 - Early Plant Retirements for additional information.

(Dollars in millions, unless otherwise noted)

In the second quarter of 2021, an overall decline in the asset group's portfolio value suggested that the carrying value of the New England asset group may be impaired. We completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the carrying value was not recoverable and that its fair value was less than its carrying value. As a result, a pre-tax impairment charge of $350 million was recorded in the second quarter of 2021 in Operating and maintenance expense in the Consolidated Statement of Operations and Comprehensive Income.

Contracted Wind Project

In the third quarter of 2021, significant long-term operational issues anticipated for a specific wind turbine technology suggested that the carrying value of a contracted wind asset, located in Maryland and part of the CRP joint venture, may be impaired. We completed a comprehensive review of the estimated undiscounted future cash flows and concluded that the carrying value of this contracted wind project was not recoverable and that its fair value was less than its carrying value. As a result, in the third quarter of 2021, a pre-tax impairment charge of $45 million was recorded in Operating and maintenance expense, $21 million of which was offset in Net income attributable to noncontrolling interests in the Consolidated Statement of Operations and Comprehensive Income.

Equity Method Investments in Certain Distributed Energy Companies

In the third quarter of 2019, our equity method investments in certain distributed energy companies were fully impaired due to an other-than-temporary decline in market conditions and underperforming projects. We recorded a pre-tax impairment charge of $164 million in Equity in losses of unconsolidated affiliates and an offsetting pre-tax $96 million in Net income attributable to noncontrolling interests in the Consolidated Statement of Operations and Comprehensive Income. As a result, we accelerated the amortization of investment tax credits associated with these companies and recorded a benefit of $46 million in Income taxes. The impairment charge and the accelerated amortization of investment tax credits resulted in a net $15 million decrease to our earnings. See Note 21 — Variable Interest Entities for additional information.

13. Intangible Assets

Our intangible assets and liabilities, included in Other current assets, Other deferred debits and other assets, Other current liabilities, Other deferred credits and other liabilities in the Consolidated Balance Sheets, consisted of the following as of December 31, 2021 and 2020. The intangible assets and liabilities shown below are generally amortized on a straight line basis, except for unamortized energy contracts which are amortized in relation to the expected realization of the underlying cash flows:

	December 31, 2021			December 31, 2020		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Unamortized Energy Contracts	$ 1,963	$ (1,673)	$ 290	$ 1,963	$ (1,642)	$ 321
Customer Relationships	330	(243)	87	326	(215)	111
Trade Name	222	(218)	4	222	(197)	25
Total	$ 2,515	$ (2,134)	$ 381	$ 2,511	$ (2,054)	$ 457

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2021, 2020, and 2019:

(Dollars in millions, unless otherwise noted)

For the Years Ended December 31,	Amortization Expense[(a)]
2021	$ 80
2020	81
2019	74

(a) See Note 22 — Supplemental Financial Information for additional information related to the amortization of unamortized energy contracts.

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2021:

For the Years Ending December 31,	Estimated Future Amortization Expense
2022	$ 60
2023	53
2024	50
2025	44
2026	37

Renewable Energy Credits

RECs are included in Renewable energy credits in the Consolidated Balance Sheets. Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are sold to a counterparty under a contract that specifically identifies a power plant is recognized at a point in time when the power is produced. This includes both bundled and unbundled REC sales. Otherwise, the revenue is recognized upon physical transfer of the REC to the customer.

The following table presents current RECs as of December 31, 2021 and 2020:

	As of December 31, 2021	As of December 31, 2020
Current REC's	$ 520	$ 621

14. Income Taxes

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Years Ended December 31,		
	2021	2020	2019
Included in operations:			
Federal			
Current	$ 394	$ 130	$ 147
Deferred	(153)	150	346
Investment tax credit amortization	(15)	(25)	(69)
State			
Current	36	40	10
Deferred	(37)	(46)	82
Total	$ 225	$ 249	$ 516

(Dollars in millions, unless otherwise noted)

Rate Reconciliation

The effective income tax rate from continuing operations varies from the U.S. federal statutory rate principally due to the following:

	For the Years Ended December 31,		
	2021[(a)]	2020[(a)]	2019[(a)]
U.S. federal statutory rate	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:			
State income taxes, net of federal income tax benefit	—	0.5	3.8
Qualified NDT fund income	165.1	23.5	12.3
Amortization of investment tax credit, including deferred taxes on basis differences	(9.0)	(2.6)	(3.0)
Production tax credits and other credits	(28.7)	(5.4)	(4.8)
Noncontrolling interests	(3.0)	3.2	(1.2)
Tax Settlements	—	(10.3)	—
Other	2.6	(0.1)	(1.2)
Effective income tax rate[(b)]	148.0 %	29.8 %	26.9 %

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(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) The higher effective tax rate in 2021 is primarily due to the impacts of the February 2021 extreme cold weather event on Income before income taxes.

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2021 and 2020 are presented below:

	As of December 31, 2021	As of December 31, 2020
Plant basis differences	$ (2,812)	$ (2,592)
Accrual based contracts	(38)	(37)
Derivatives and other financial instruments	(172)	(41)
Deferred pension and postretirement obligation	(274)	(236)
Nuclear decommissioning activities	(912)	(742)
Deferred debt refinancing costs	15	16
Tax loss carryforward	53	55
Tax credit carryforward, net of valuation allowances	778	838
Investment in partnerships	(252)	(813)
Other, net	312	347
Deferred income tax liabilities (net)	$ (3,302)	$ (3,205)
Unamortized investment tax credits[(a)]	(369)	(445)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (3,671)	$ (3,650)

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(a) Does not include unamortized investment tax credits reclassified to liabilities held for sale as of December 31, 2020.

The following table provides our carryforwards, of which the state related items are presented on a post-apportioned basis, and any corresponding valuation allowances as of December 31, 2021.

(Dollars in millions, unless otherwise noted)

Federal		As of December 31, 2021
Federal general business credits carryforwards and other carryforwards[(a)]	$	806
State		
State net operating losses and other carryforwards		869
Deferred taxes on state tax attributes (net)		74
Valuation allowance on state tax attributes		22
Year in which net operating loss or credit carryforwards will begin to expire[(a)]		2035

(a) The federal general business credit carryforward will begin expiring in 2035.

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits.

		Unrecognized tax benefits
Balance as of December 31, 2018	$	408
Change to positions that only affect timing		12
Increases based on tax positions related to 2019		1
Increases based on tax positions prior to 2019		19
Decreases based on tax positions prior to 2019		(3)
Increase from settlements with taxing authorities		4
Balance as of December 31, 2019		441
Increases based on tax positions related to 2020		1
Increases based on tax positions prior to 2020		23
Decreases based on tax positions prior to 2020[(a)]		(346)
Decrease from settlements with taxing authorities[(a)]		(69)
Balance as of December 31, 2020		50
Change to positions that only affect timing		(1)
Increases based on tax positions related to 2021		1
Increases based on tax positions prior to 2021		1
Decreases based on tax positions prior to 2021		(2)
Balance as of December 31, 2021	$	49

(a) Our unrecognized federal and state tax benefits decreased in the first quarter of 2020 by approximately $411 million due to the settlement of a federal refund claim with IRS Appeals. The recognition of these tax benefits resulted in an increase in net income of $73 million in the first quarter of 2020, reflecting a decrease to income tax expense of $67 million.

Recognition of unrecognized tax benefits

The following table presents the unrecognized tax benefits that, if recognized, would decrease the effective tax rate.

December 31, 2021	$	39
December 31, 2020		39
December 31, 2019		429

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

No amounts are expected to significantly increase or decrease within 12 months after the reporting date.

Total amounts of interest and penalties recognized

(Dollars in millions, unless otherwise noted)

We did not record material interest and penalty expense related to tax positions reflected in the Consolidated Balance Sheets. Interest expense and penalty expense are recorded in Interest expense, net and Other, net, respectively, in Other income and deductions in the Consolidated Statements of Operations and Comprehensive Income.

Description of tax years open to assessment by major jurisdiction

Major Jurisdiction	Open Years[(a)]
Federal consolidated income tax returns	2010-2020
Illinois unitary corporate income tax returns	2012-2020
New Jersey separate corporate income tax returns	2017-2018
New York combined corporate income tax returns	2011-2020
Pennsylvania separate corporate income tax returns	2011-2016
Pennsylvania separate corporate income tax returns	2018-2020

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(a) Tax years open to assessment include years when we were consolidated by Exelon. See discussion below under the Tax Matters Agreement for responsibility of taxes of these open years.

Other Tax Matters

CENG Put Option

On August 6, 2021, we entered into a settlement agreement with EDF pursuant to which we purchased EDF's equity interest in CENG. We recorded deferred tax liabilities of $288 million against Membership interest in the Consolidated Balance Sheet. The deferred tax liabilities represent the tax effect on the difference between the net purchase price and EDF's noncontrolling interest as of August 6, 2021. The deferred tax liabilities will reverse during the remaining operating lives and during decommissioning of the CENG nuclear plants. See Note 2 – Mergers, Acquisitions, and Dispositions for additional information.

Allocation of Tax Benefits

We are a party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net federal and state benefits attributable to Exelon were reallocated to the parties. That allocation was treated as a contribution from Exelon to the party receiving the benefit.

The following table presents the allocation of tax benefits from Exelon to us under the Tax Sharing Agreement.

December 31, 2021	$	64
December 31, 2020		64
December 31, 2019		41

Research and Development Activities

In the fourth quarter of 2019, we recognized additional tax benefits related to certain research and development activities that qualify for federal and state tax incentives for the 2010 through 2018 tax years, which resulted in an increase in net income of $75 million for the year ended December 31, 2019, reflecting a decrease in Income tax expense of $66 million.

Tax Matters Agreement

In connection with the separation, we entered into a Tax Matters Agreement ("TMA") with Exelon. The TMA will govern the respective rights, responsibilities, and obligations between us and Exelon after the separation with respect to tax liabilities and benefits, tax attributes, tax returns, tax contests and other tax sharing regarding U.S. federal, state, local and foreign income taxes, other tax matters and related tax returns.

Responsibility and Indemnification for Taxes. As a former subsidiary of Exelon, we will have joint and several liability with Exelon to the IRS and certain state jurisdictions relating to the taxable periods that we were included in federal and state filings. However, the TMA specifies the portion of this tax liability for which we will bear contractual responsibility, and we and Exelon will each agree to indemnify each other against any amounts for which such indemnified party is not responsible. Specifically, we will generally be liable for taxes due and payable in connection with tax returns that we are required to file. We will also generally be liable for our share of certain taxes required to be paid by Exelon with respect to taxable years or periods (or portions thereof) ending on or prior to the separation to the extent that we would have been responsible for such taxes under the existing Exelon tax sharing agreement.

Tax Refunds and Attributes. The TMA will provide for the allocation of certain pre-closing tax attributes between us and Exelon. Tax attributes generally will be allocated in accordance with the principles set forth in the existing Exelon tax sharing agreement, unless otherwise required by law. Under the TMA, we will generally be entitled to refunds for taxes for which we are responsible. In addition, it is expected that after the separation, Exelon will have tax credit carryforwards that may be used to offset Exelon's future tax liabilities. A significant portion of such carryforwards were generated by our business, and we recognized a receivable upon separation for the tax credit carryforwards expected to be utilized by Exelon after separation in accordance with the terms of the TMA.

15. Retirement Benefits

Substantially all our current employees participated in Exelon-sponsored defined benefit pension plans and OPEB plans as of December 31, 2021. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, for most newly-hired non-represented, non-craft, employees, and for certain newly-hired union employees pursuant to their collective bargaining agreements, these newly-hired employees are not eligible for pension benefits, and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented, non-craft, employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits. Effective January 1, 2021, most non-represented, non-craft, employees who are under the age of 40 are not eligible for retiree health care benefits. Effective January 1, 2022, management employees retiring on or after that date are no longer eligible for retiree life insurance benefits.

The tables below show the pension and OPEB plans in which our employees participated as of December 31, 2021:

Name of Plan
Qualified Pension Plans:
Exelon Corporation Retirement Program[a]
Exelon Corporation Pension Plan for Bargaining Unit Employees[a]
Exelon New England Union Employees Pension Plan[a]
Exelon Employee Pension Plan for Clinton, TMI, and Oyster Creek[a]
Pension Plan of Constellation Energy Group, Inc.[b]
Pension Plan of Constellation Energy Nuclear Group, LLC[c]
Nine Mile Point Pension Plan[c]
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B[b]
Pepco Holdings LLC Retirement Plan[d]
Non-Qualified Pension Plans:
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan[a]
Exelon Corporation Supplemental Management Retirement Plan[a]
Constellation Energy Group, Inc. Senior Executive Supplemental Plan[b]
Constellation Energy Group, Inc. Supplemental Pension Plan[b]
Constellation Energy Group, Inc. Benefits Restoration Plan[b]
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan[c]
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan[c]
Baltimore Gas & Electric Company Executive Benefit Plan[b]
Baltimore Gas & Electric Company Manager Benefit Plan[b]
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan[d]
Conectiv Supplemental Executive Retirement Plan[d]
OPEB Plans:
PECO Energy Company Retiree Medical Plan[a]
Exelon Corporation Health Care Program[a]
Exelon Corporation Employees' Life Insurance Plan[a]
Exelon Corporation Health Reimbursement Arrangement Plan[a]
Constellation Energy Group, Inc. Retiree Medical Plan[b]
Constellation Energy Group, Inc. Retiree Dental Plan[b]
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan[b]
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan[b]
Exelon New England Union Post-Employment Medical Savings Account Plan[a]
Retiree Medical Plan of Constellation Energy Nuclear Group, LLC[c]
Retiree Dental Plan of Constellation Energy Nuclear Group, LLC[c]
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees[c]
Pepco Holdings LLC Welfare Plan for Retirees[d]

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(a) These plans are collectively referred to as the legacy Exelon plans.
(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the legacy CENG plans.
(d) These plans are collectively referred to as the legacy PHI plans.

Costs Allocation from Exelon

We account for our participation in Exelon's pension and OPEB plans by applying multi-employer accounting. Exelon allocates costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan.

(Dollars in millions, unless otherwise noted)

We were allocated pension and OPEB costs from Exelon of $123 million, $115 million, and $135 million for the years ended December 31, 2021, 2020, and 2019, respectively. We include the service cost and non-service cost components in Operating and maintenance expense and Property, plant, and equipment, net (where criteria for capitalization of direct labor has been met) in the consolidated financial statements.

Contributions

Exelon allocates contributions related to its legacy Exelon pension and OPEB plans to its subsidiaries based on accounting cost. For legacy CEG, CENG, FitzPatrick, and PHI plans, pension and OPEB contributions are allocated to the subsidiaries based on employee participation (both active and retired). The following tables provide our contributions to the pension and OPEB plans:

Pension Benefits			OPEB		
2021	2020	2019	2021	2020	2019
$ 231	$ 236	$ 160	$ 28	$ 19	15

Exelon considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status on an Accumulated Benefit Obligation ("ABO") basis over time. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon's management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery).

Defined Contribution Savings Plan

We participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. We match a percentage of the employee contributions up to certain limits. The matching contributions to the savings plan were $53 million, $63 million, and $73 million for the years ended December 31, 2021, 2020, and 2019, respectively.

Impact of Separation from Exelon

Effective February 1, 2022, in connection with the separation, pension and OPEB obligations and the related plan assets for participants were transferred to pension and OPEB plans established by us as the plan sponsor.

As the plan sponsor, effective with the first quarter of 2022, our Consolidated Balance Sheet will reflect an unfunded projected benefit obligation ("PBO") equal to an excess of the PBO over the fair value of the plan assets, consistent with a single employer benefit plan approach. We will no longer account for our participation in Exelon's pension and OPEB plans under the multi-employer benefit plan approach that has historically resulted in recognition of a net prepaid pension asset in our Consolidated Balance Sheets representing an excess of contributions over cumulative costs.

In addition, we will be required to report the service cost and other non-service cost components of net periodic benefit costs for all plans separately in our Consolidated Statements of Operations and Comprehensive Income. Effective in the first quarter of 2022, the service cost component will be included in Operating and maintenance expense and Property, plant, and equipment, net (where criteria for capitalization of direct labor has been met) while the non-service cost components will be included in Other, net.

We have also established various 401(k) defined contribution savings plans that are now sponsored by us. Refer to Note 24 — Separation from Exelon for additional details on the separation.

The following table provides our planned contributions to our qualified pension plans, non-qualified pension plans, and OPEB plans in 2022 (including our benefit payments related to unfunded plans):

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Planned contributions	$ 192	$ 9	$ 11

16. Derivative Financial Instruments

We use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. All derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, our energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Our use of cash collateral is generally unrestricted unless we are downgraded below investment grade.

Commodity Price Risk

We employ established policies and procedures to manage our risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. We believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

To the extent the amount of energy we produce differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. We use a variety of derivative and non-derivative instruments to manage the commodity price risk of our electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, we may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. We are also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

(Dollars in millions, unless otherwise noted)

Additionally, we are exposed to certain market risks through our proprietary trading activities. The proprietary trading activities are a complement to our energy marketing portfolio but represent a small portion of our overall energy marketing activities and are subject to limits established by the RMC.

The following tables provide a summary of the derivative fair value balances recorded as of December 31, 2021 and 2020:

December 31, 2021	Economic Hedges	Proprietary Trading	Collateral (a)(b)	Netting(a)	Total
Mark-to-market derivative assets (current assets)	$ 10,915	$ 25	$ 152	$ (8,923)	$ 2,169
Mark-to-market derivative assets (noncurrent assets)	3,224	2	15	(2,298)	943
Total mark-to-market derivative assets	14,139	27	167	(11,221)	3,112
Mark-to-market derivative liabilities (current liabilities)	(10,143)	(19)	262	8,923	(977)
Mark-to-market derivative liabilities (noncurrent liabilities)	(2,893)	(1)	83	2,298	(513)
Total mark-to-market derivative liabilities	(13,036)	(20)	345	11,221	(1,490)
Total mark-to-market derivative net assets (liabilities)	$ 1,103	$ 7	$ 512	$ —	$ 1,622
December 31, 2020					
Mark-to-market derivative assets (current assets)	$ 2,757	$ 40	$ 103	$ (2,261)	$ 639
Mark-to-market derivative assets (noncurrent assets)	1,501	4	64	(1,015)	554
Total mark-to-market derivative assets	4,258	44	167	(3,276)	1,193
Mark-to-market derivative liabilities (current liabilities)	(2,629)	(23)	131	2,261	(260)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,335)	(2)	118	1,015	(204)
Total mark-to-market derivative liabilities	(3,964)	(25)	249	3,276	(464)
Total mark-to-market derivative net assets (liabilities)	$ 294	$ 19	$ 416	$ —	$ 729

(a) We net all available amounts allowed under the derivative authoritative guidance in the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases we may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These amounts are not material as of December 31, 2021 and 2020 and not reflected in the table above.
(b) Includes $897 million held and $209 million posted of variation margin on the exchanges as of December 31, 2021 and 2020, respectively.

Economic Hedges (Commodity Price Risk)

For the years ended December 31, 2021, 2020, and 2019, we recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

	Gain (Loss)		
Income Statement Location	2021	2020	2019
Operating revenues	$ (635)	$ 112	$ —
Purchased power and fuel	1,206	168	(204)
Total	$ 571	$ 280	$ (204)

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis. We may also enter into transactions that are outside of this ratable hedging program. As of December 31, 2021, the percentage of expected generation hedged for the Mid-

Atlantic, Midwest, New York, and ERCOT reportable segments is 92%-95% and 73%-76% for 2022 and 2023, respectively.

Proprietary Trading (Commodity Price Risk)

We also execute commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in the Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the years ended December 31, 2021, 2020, and 2019, net pre-tax commodity mark-to-market gains and losses were not material.

Interest Rate and Foreign Exchange Risk

We utilize interest rate swaps to manage our interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were $486 million and $665 million as of December 31, 2021 and 2020, respectively.

The mark-to-market derivative assets and liabilities as of December 31, 2021 and 2020 and the mark-to-market gains and losses for the years ended December 31, 2021, 2020, and 2019 were not material.

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts as of the reporting date.

For commodity derivatives, we enter into enabling agreements that allow for payment netting with our counterparties, which reduces our exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allows for cross product netting. In addition to payment netting language in the enabling agreement, our credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with us as specified in each enabling agreement. Our credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on the credit exposure for all derivative instruments, NPNS and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

(Dollars in millions, unless otherwise noted)

Rating as of December 31, 2021	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 715	$ 176	$ 539	1	$ 106
Non-investment grade	13	—	13	—	—
No external ratings					
Internally rated — investment grade	111	—	111	—	—
Internally rated — non-investment grade	226	47	179	—	—
Total	$ 1,065	$ 223	$ 842	1	$ 106

Net Credit Exposure by Type of Counterparty	As of December 31, 2021
Financial institutions	$ 32
Investor-owned utilities, marketers, power producers	711
Energy cooperatives and municipalities	62
Other	37
Total	$ 842

(a) As of December 31, 2021, credit collateral held from counterparties where we had credit exposure included $163 million of cash and $60 million of letters of credit. The credit collateral does not include non-liquid collateral.

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of our derivative instruments contain provisions that require us to post collateral. We also enter into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon our credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk related contingent features stipulate that if we were to be downgraded or lose our investment grade credit rating (based on our senior unsecured debt rating), we would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, we believe an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Features	As of December 31, 2021	As of December 31, 2020
Gross fair value of derivative contracts containing this feature[(a)]	$ (3,872)	$ (834)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	2,424	537
Net fair value of derivative contracts containing this feature[(c)]	$ (1,448)	$ (297)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features ignoring the effects of master netting agreements.

(Dollars in millions, unless otherwise noted)

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which we could potentially be required to post collateral.
(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of December 31, 2021 and 2020, we posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	As of December 31,	
	2021	2020
Cash collateral posted	$ 713	$ 511
Letters of credit posted	755	226
Cash collateral held	182	110
Letters of credit held	124	40
Additional collateral required in the event of a credit downgrade below investment grade	2,113	1,432

We entered into supply forward contracts with certain utilities with one-sided collateral postings only from us. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including us, are required to post collateral once certain unsecured credit limits are exceeded.

17. Debt and Credit Agreements

Short-Term Borrowings

We meet our short-term liquidity requirements primarily through the issuance of commercial paper. We may use our credit facility for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects our commercial paper program supported by the revolving credit agreements and bilateral credit agreements as of December 31, 2021 and 2020:

Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings at December 31,	
2021[(a)(b)]	2020[(a)(b)]	2021	2020	2021	2020
$ 5,300	$ 5,300	$ 702	$ 340	0.66 %	0.27 %

(a) Excludes $1,200 million and $1,500 million in bilateral credit facilities as of December 31, 2021 and 2020, respectively, and $131 million and $144 million in credit facilities for project finance as of December 31, 2021 and 2020, respectively. These credit facilities do not back our commercial paper program.
(b) As of December 31, 2021, excludes $44 million of credit facility agreements arranged at minority and community banks. These facilities expire on October 7, 2022 and are solely utilized to issue letters of credit. As of December 31, 2020, excludes $38 million of credit facility agreements arranged at minority and community banks.

In order to maintain our commercial paper program in the amounts indicated above, we must have a credit facility in place, at least equal to the amount of our commercial paper program. We do not issue commercial paper in an aggregate amount exceeding the then available capacity under our credit facility.

(Dollars in millions, unless otherwise noted)

As of December 31, 2021, we had the following aggregate bank commitments, credit facility borrowings and available capacity under our respective credit facilities:

				Available Capacity as of December 31, 2021	
Facility Type	Aggregate Bank Commitment[(b)]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Syndicated Revolver[(a)]	$ 5,300	$ —	$ 1,230	$ 4,070	$ 3,368
Bilaterals	1,200	—	1,029	171	—
Project Finance	131	—	116	15	—

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(a) Our syndicated revolving credit facility was replaced by the $3.5 billion 5-year revolving credit agreement entered into on February 1, 2022 in connection with our separation.
(b) Excludes $44 million of credit facility agreements arranged at minority and community banks. These facilities expire on October 7, 2022 and are solely utilized to issue letters of credit. As of December 31, 2021, letters of credit issued under these facilities totaled $5 million.

Impact of Separation from Exelon

In connection with our separation from Exelon, we entered into two new credit agreements that replaced our $5.3 billion syndicated revolving credit facility. On February 1, 2022, we entered into a new credit agreement establishing a $3.5 billion five-year revolving credit facility at a variable interest rate of SOFR plus 1.275% and on February 9, 2022 we entered into a $1 billion five-year liquidity facility with the primary purpose of supporting our letter of credit issuances. Many of our bilateral credit agreements remain in effect. See below for additional details.

Bilateral Credit Agreements

The following table reflects the bilateral credit agreements at December 31, 2021:

Date Initiated		Latest Amendment Date	Maturity Date(a)	Amount
January 11, 2013	(b)(c)	March 1, 2021	March 1, 2023	$ 100
January 5, 2016	(b)	April 2, 2021	April 5, 2023	150
February 21, 2019	(b)(c)	March 31, 2021	March 31, 2022	100
October 25, 2019	(b)	N/A	N/A	200
November 20, 2019	(b)	N/A	N/A	300
November 21, 2019	(b)	N/A	N/A	150
November 21, 2019	(b)	November 21, 2021	November 21, 2022	100
May 15, 2020	(b)(d)	N/A	N/A	100

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(a) Credit facilities that do not contain a maturity date are specific to the agreements set within each contract. In some instances, credit facilities are automatically renewed based on the contingency standards set within the specific agreement.
(b) Bilateral credit agreements solely support the issuance of letters of credit and do not back our commercial paper program.
(c) The bilateral credit agreement was terminated on January 31, 2022.
(d) On February 9, 2022, the bilateral credit agreement increased to $200 million.

Borrowings under our revolving credit agreement bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon our credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are 27.5 basis points and 127.5 basis points, respectively.

If we lose our investment grade rating, the maximum adders for prime rate borrowings and LIBOR-based rate borrowings would be 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

(Dollars in millions, unless otherwise noted)

Short-Term Loan Agreements

On March 19, 2020, we entered into a term loan agreement for $200 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in the Consolidated Balance Sheet. In connection with the separation, we repaid the term loan on January 26, 2022. See Note 24 — Separation from Exelon for additional information

On March 31, 2020, we entered into a term loan agreement for $300 million. The loan agreement was renewed on March 30, 2021 and will expire on March 29, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.70% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in the Consolidated Balance Sheet.

On August 6, 2021, we entered into a 364-day term loan agreement for $880 million to fund the purchase of EDF's equity interest in CENG. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate of LIBOR plus 0.875% until March 31, 2022 and a rate of LIBOR plus 1% thereafter and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in the Consolidated Balance Sheet. The loan agreement was amended on January 24, 2022 to change the maturity date to June 30, 2022 from August 5, 2022. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Long-Term Debt

The following table presents the outstanding long-term debt as of December 31, 2021 and 2020:

	Rates		Maturity Date	December 31, 2021	December 31, 2020
Long-term debt					
Senior unsecured notes	3.25 % -	7.60 %	2022 - 2042	$ 4,219	$ 4,219
Notes payable and other	2.10 % -	4.85 %	2022 - 2028	103	111
Nonrecourse debt:					
Fixed rates	2.29 % -	6.00 %	2031 - 2037	909	977
Variable rates	2.98 % -	3.50 %	2026 - 2027	870	765
Total long-term debt				6,101	6,072
Unamortized debt discount and premium, net				(7)	(5)
Unamortized debt issuance costs				(42)	(46)
Fair value adjustment				62	66
Long-term debt due within one year				(1,220)	(197)
Long-term debt				$ 4,894	$ 5,890

Long-term debt maturities in the periods 2022 through 2026 and thereafter are as follows:

2022	$ 1,220
2023	1
2024	1
2025	901
2026	114
Thereafter	3,864
Total	$ 6,101

Long-Term Debt from Affiliates

In connection with the debt obligations assumed by Exelon as part of the 2012 merger, Exelon and our subsidiaries assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable to Exelon Corporate. As of December 31, 2021 and 2020, we had $319 million and $324 million, respectively, recorded to intercompany notes payable to Exelon Corporate. In connection with the separation, on January 31, 2022, we paid cash to Exelon Corporate in the amount of $258 million to settle the intercompany loan. See Note 24 — Separation from Exelon for additional information.

Debt Covenants

As of December 31, 2021, we are in compliance with debt covenants.

Nonrecourse Debt

We have also issued nonrecourse debt, for which approximately $2 billion of generating assets have been pledged as collateral as of December 31, 2021. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against us in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy the associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2021 and 2020, approximately $435 million and $460 million were outstanding, respectively. In addition, we have issued letters of credit to support the equity investment in the project, with $37 million outstanding as of December 31, 2021. In December 2017, our interests in Antelope Valley were contributed to and are pledged as collateral for the CR financing structures referenced below.

Continental Wind, LLC. In September 2013, Continental Wind, our indirect subsidiary, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667 MW. The net proceeds were distributed to us for general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2021 and December 31, 2020, approximately $380 million and $415 million were outstanding, respectively.

In addition, Continental Wind has a $122 million letter of credit facility and $4 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2021, the Continental Wind letter of credit facility had $115 million in letters of credit outstanding related to the project.

In 2017, our interests in Continental Wind were contributed to CRP. Refer to Note 21 - Variable Interest Entities for additional information on CRP.

Renewable Power Generation. In March 2016, RPG, our indirect subsidiary, issued $150 million aggregate principal amount of nonrecourse senior secured notes. The net proceeds were distributed to us for paydown of long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2021 and December 31, 2020, approximately $90 million and $95 million were outstanding, respectively. In 2017, our interests in RPG were contributed to CRP. Refer to Note 21 - Variable Interest Entities for additional information on CRP.

SolGen, LLC. In September 2016, SolGen, an indirect subsidiary, issued $150 million aggregate principal amount of nonrecourse senior secured notes. The net proceeds were distributed to us for general business purposes. On December 8, 2020, we entered into agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of our solar business. The sale was completed on March 31, 2021 in which the buyer assumed the $125 million outstanding debt. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale agreement.

Constellation Renewables. In November 2017, CR, our indirect subsidiary, entered into an $850 million nonrecourse senior secured term loan credit facility agreement with a maturity date of November 28, 2024. In addition to the financing, CR entered into interest rate swaps with an initial notional amount of $636 million at an interest rate of 2.32% to manage a portion of the interest rate exposure in connection with the financing.

In December 2020, CR entered into a financing agreement for a $750 million nonrecourse senior secured term loan credit facility, scheduled to mature on December 15, 2027. The term loan bears interest at a variable rate equal to LIBOR plus 2.50%, subject to a 1% LIBOR floor with interest payable quarterly. In addition to the financing, CR entered into interest rate swaps with an initial notional amount of $516 million at an interest rate of 1.05% to manage a portion of the interest rate exposure in connection with the financing.

The proceeds were used to repay the November 2017 nonrecourse senior secured term loan credit facility of $850 million, of which $709 million was outstanding as of the retirement date in December of 2020, and to settle the November 2017 interest rate swap. Our interests in CRP and Antelope Valley remain contributed to and pledged as collateral for this financing. As of December 31, 2021 and December 31, 2020, $735 million and $750 million was outstanding, respectively. See Note 21 — Variable Interest Entities for additional information on CRP and Note 16 — Derivative Financial Instruments for additional information on interest rate swaps.

West Medway II, LLC. On May 13, 2021, West Medway II, LLC (West Medway II), our indirect subsidiary, entered into a financing agreement for a $150 million nonrecourse senior secured term loan credit facility with a maturity date of March 31, 2026. The term loan bears interest at an average blended interest rate of LIBOR plus 3%, paid quarterly. In addition to the financing, West Medway II, entered into interest rate swaps with an initial notional amount of $113 million at an interest rate of 0.61%, paid quarterly, to manage a portion of the interest rate exposure in connection with the financing. We used the net proceeds for general corporate purposes. Our interests in West Medway II, were pledged as collateral for this financing. As of December 31, 2021, approximately $135 million was outstanding. See Note 16 — Derivative Financial Instruments for additional information on interest rate swaps.

18. Fair Value of Financial Assets and Liabilities

We measure and classify fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

(Dollars in millions, unless otherwise noted)

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the short-term liabilities, long-term debt, and the SNF obligation as of December 31, 2021 and 2020. We have no financial liabilities classified as Level 1.

The carrying amounts of the short-term liabilities as presented in the Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	December 31, 2021				December 31, 2020			
	Carrying Amount	Fair Value			Carrying Amount	Fair Value		
		Level 2	Level 3	Total		Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year	$ 6,114	$ 5,749	$ 1,093	$ 6,842	$ 6,087	$ 5,648	$ 1,208	$ 6,856
SNF Obligation	1,210	1,060	—	1,060	1,208	909	—	909

We use the following methods and assumptions to estimate fair value of financial liabilities recorded at carrying cost:

Type	Level	Valuation
Long-term Debt, including amounts due within one year		
Taxable Debt Securities	2	The fair value is determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. We obtain credit spreads based on trades of our existing debt securities as well as other issuers in the utility sector with similar credit ratings. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.
Variable Rate Financing Debt	2	Debt rates are reset on a regular basis and the carrying value approximates fair value.
Government Backed Fixed Rate Project Financing Debt	3	The fair value is similar to the process for taxable debt securities. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable U.S. Treasury rate as well as a current market curve derived from government-backed securities.
Non-Government Backed Fixed Rate Nonrecourse Debt	3	Fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project.
SNF Obligation		
SNF Obligation	2	The carrying amount is derived from a contract with the DOE to provide for disposal of SNF from certain of our nuclear generating stations. See Note 19 — Commitments and Contingencies for further details. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week U.S. Treasury rate. The compounded obligation amount is discounted back to present value using our discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2035.

Recurring Fair Value Measurements

The following tables present assets and liabilities measured and recorded at fair value in the Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2021 and 2020:

(Dollars in millions, unless otherwise noted)

	As of December 31, 2021					As of December 31, 2020				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[a]	$ 113	$ —	$ —	$ —	$ 113	$ 124	$ —	$ —	$ —	$ 124
NDT fund investments										
Cash equivalents[b]	465	116	—	—	581	210	95	—	—	305
Equities	4,564	1,805	—	1,645	8,014	3,886	2,077	—	1,562	7,525
Fixed income										
Corporate debt[c]	—	1,145	286	—	1,431	—	1,485	285	—	1,770
U.S. Treasury and agencies	2,193	30	—	—	2,223	1,871	126	—	—	1,997
Foreign governments	—	60	—	—	60	—	56	—	—	56
State and municipal debt	—	26	—	—	26	—	101	—	—	101
Other	29	23	—	1,449	1,501	—	41	—	961	1,002
Fixed income subtotal	2,222	1,284	286	1,449	5,241	1,871	1,809	285	961	4,926
Private credit	—	—	178	624	802	—	—	212	629	841
Private equity	—	—	—	673	673	—	—	—	504	504
Real estate	—	—	—	864	864	—	—	—	679	679
NDT fund investments subtotal[d][e]	7,251	3,205	464	5,255	16,175	5,967	3,981	497	4,335	14,780
Rabbi trust investments										
Cash equivalents	3	—	—	—	3	4	—	—	—	4
Mutual funds	36	—	—	—	36	29	—	—	—	29
Life insurance contracts	—	33	—	—	33	—	28	—	—	28
Rabbi trust investments subtotal	39	33	—	—	72	33	28	—	—	61
Investments in equities[f]	43	—	—	—	43	195	—	—	—	195
Commodity derivative assets										
Economic hedges	3,017	7,223	3,899	—	14,139	745	1,914	1,599	—	4,258
Proprietary trading	—	19	8	—	27	—	17	27	—	44
Effect of netting and allocation of collateral[g][h]	(2,108)	(6,177)	(2,769)	—	(11,054)	(607)	(1,597)	(905)	—	(3,109)
Commodity derivative assets subtotal	909	1,065	1,138	—	3,112	138	334	721	—	1,193
DPP consideration	—	365	—	—	365	—	639	—	—	639
Total assets	8,355	4,668	1,602	5,255	19,880	6,457	4,982	1,218	4,335	16,992
Liabilities										
Commodity derivative liabilities										
Economic hedges	(2,201)	(6,870)	(3,965)	—	(13,036)	(682)	(1,928)	(1,354)	—	(3,964)
Proprietary trading	—	(18)	(2)	—	(20)	—	(21)	(4)	—	(25)
Effect of netting and allocation of collateral[g][h]	2,189	6,642	2,735	—	11,566	540	1,918	1,067	—	3,525
Commodity derivative liabilities subtotal	(12)	(246)	(1,232)	—	(1,490)	(142)	(31)	(291)	—	(464)
Deferred compensation obligation	—	(43)	—	—	(43)	—	(42)	—	—	(42)
Total liabilities	(12)	(289)	(1,232)	—	(1,533)	(142)	(73)	(291)	—	(506)
Total net assets	$ 8,343	$ 4,379	$ 370	$ 5,255	$ 18,347	$ 6,315	$ 4,909	$ 927	$ 4,335	$ 16,486

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(a) We exclude cash of $417 million and $171 million as of December 31, 2021 and 2020, respectively, and restricted cash of $46 million and $20 million as of December 31, 2021 and 2020, respectively.
(b) Includes $116 million of cash received from outstanding repurchase agreements as of both December 31, 2021 and 2020, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.
(c) Includes investments in equities sold short of $(55) million and $(62) million as of December 31, 2021 and 2020, respectively, held in an investment vehicle primarily to hedge the equity option component of convertible debt.
(d) Includes net derivative liabilities of $1 million and net derivative assets of $2 million, which have total notional amounts of $687 million and $1,043 million as of December 31, 2021 and 2020, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of our exposure to credit or market loss.
(e) Excludes net liabilities of $111 million and $181 million as of December 31, 2021 and 2020, respectively, which include certain derivative assets that have notional amounts of $182 million and $104 million as of December 31, 2021 and 2020, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.
(f) Includes equity investments which were previously designated as equity investments without readily determinable fair values but are now publicly traded and therefore have readily determinable fair values. The first investment became publicly traded in the fourth quarter of 2020. The fair value of these investments is recorded in Other current assets in the Consolidated Balance Sheets based on the quoted market prices of the stocks as of the respective balance sheet date. Unrealized (losses)/gains of $(160) million and $186 million were recorded in Other, net in the Consolidated Statement of Operations and Comprehensive Income for the years ended December 31, 2021 and 2020, respectively.
(g) Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $81 million, $465 million, and $(34) million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2021. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $(67) million, $321 million, and $162 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2020.
(h) Includes $897 million held and $209 million posted of variation margin with the exchanges as of December 31, 2021 and 2020, respectively.

As of December 31, 2021, we have outstanding commitments to invest in private credit, private equity, and real estate investments of $306 million, $171 million, and $459 million, respectively. These commitments will be funded by our existing NDT funds.

We hold investments without readily determinable fair values with carrying amounts of $33 million and $55 million as of December 31, 2021 and 2020, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the years ended December 31, 2021 and 2020.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2021 and 2020:

(Dollars in millions, unless otherwise noted)

	For the Year Ended December 31, 2021		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of January 1, 2021	$ 497	$ 430	$ 927
Total realized / unrealized gains (losses)			
Included in net income	5	(812) (a)	(807)
Included in noncurrent payables to affiliates	19	—	19
Change in collateral	—	(196)	(196)
Purchases, sales, issuances and settlements			
Purchases	4	162	166
Sales	—	(10)	(10)
Settlements	(61)	—	(61)
Transfers into Level 3	—	19 (b)	19
Transfers out of Level 3	—	313 (b)	313
Balance as of December 31, 2021	$ 464	$ (94)	$ 370
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2021	$ 5	$ (1,222)	$ (1,217)

	For the Year Ended December 31, 2020		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of January 1, 2020	$ 511	$ 817	$ 1,328
Total realized / unrealized gains (losses)			
Included in net income	2	(414) (a)	(412)
Included in noncurrent payables to affiliates	21	—	21
Change in collateral	—	(53)	(53)
Purchases, sales, issuances and settlements			
Purchases	8	143	151
Sales	—	(27)	(27)
Settlements	(45)	—	(45)
Transfers into Level 3	—	(12) (b)	(12)
Transfers out of Level 3	—	(24) (b)	(24)
Balance as of December 31, 2020	$ 497	$ 430	$ 927
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2020	$ 2	$ 6	$ 8

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(a) Includes an addition of $410 million for realized losses and a reduction of $420 million for realized gains due to the settlement of derivative contracts for the years ended December 31, 2021 and 2020, respectively.
(b) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable, respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following table presents the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2021 and 2020:

(Dollars in millions, unless otherwise noted)

	Operating Revenues	Purchased Power and Fuel	Other, net
Total (losses) gains included in net income for the year ended December 31, 2021	$ (1,343)	$ 531	$ 5
Total unrealized (losses) gains for the year ended December 31, 2021	(1,577)	355	5
Total (losses) gains included in net income for the year ended December 31, 2020	$ (404)	$ (10)	$ 2
Total unrealized (losses) gains for the year ended December 31, 2020	(31)	37	2

Valuation Techniques Used to Determine Fair Value

Cash Equivalents. Investments with original maturities of three months or less when purchased, including mutual and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

NDT Fund Investments. The trust fund investments have been established to satisfy our nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in equities and fixed income. Our NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments, including private credit, private equity, and real estate. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

Equities. These investments consist of individually held equity securities, equity mutual funds, and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which we are able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights, and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. The equity securities that are held directly by the trust funds are valued based on quoted prices in active markets and categorized as Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and fund investments are held in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets on the underlying securities and are not classified within the fair value hierarchy. These investments can typically be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, U.S. government securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds, and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class, or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. We have obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, we selectively corroborate the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold fund investments in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Derivative instruments. These instruments, consisting primarily of futures and swaps to manage risk, are recorded at fair value. Over-the-counter derivatives are valued daily, based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private credit. Private credit investments primarily consist of investments in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private credit investments held directly by us are categorized as Level 3 because they are based largely on inputs that are unobservable and utilize complex valuation models. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Managed private credit fund investments are not classified within the fair value hierarchy because their fair value is determined using NAV or its equivalent as a practical expedient.

Private equity. These investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments, and investments in natural resources. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on our understanding of the investment funds. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows, and market based comparable data. These valuation inputs are unobservable. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Real estate. These investments are funds with a direct investment in pools of real estate properties. These funds are reported by the fund manager and are generally based on independent appraisals of the underlying investments from sources with professional qualifications, typically using a combination of market based comparable data and discounted cash flows. These valuation inputs are unobservable. Certain real estate investments cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on our understanding of the investments funds. The remaining liquid real estate investments are generally redeemable from the investment vehicle quarterly, with 30 to 90 days of notice. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

We evaluated our NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2021. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2021, there were no significant concentrations (generally defined as greater than 10 percent) of risk in the NDT assets.

See Note 10 — Asset Retirement Obligations for additional information on the NDT fund investments.

Rabbi Trust Investments. The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of executive management and directors. The Rabbi trusts' assets are included in investments in the Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, and life insurance policies. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets.

Deferred Compensation Obligations. Our deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. We include such plans in other current and noncurrent liabilities in the Consolidated Balance Sheets. The value of our deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the table above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Investments in Equities. We hold certain investments in equity securities with readily determinable fair values in addition to those held within the NDT funds. These equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Deferred Purchase Price Consideration. We have DPP consideration for the sale of certain receivables of retail electricity. This amount is valued based on the sales price of the receivables net of allowance for credit losses based on accounts receivable aging historical experience coupled with specific identification through a credit monitoring process, which considers current conditions and forward-looking information such as industry trends, macroeconomic factors, changes in the regulatory environment, external credit ratings, publicly available news, payment status, payment history, and the exercise of collateral calls. Since the DPP consideration is based on the sales price of the receivables, it is categorized as Level 2 in the fair value hierarchy. See Note 6 — Accounts Receivable for additional information on the sale of certain receivables.

Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that we believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads, and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness, and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps, and options, model inputs are generally observable. Such instruments are categorized in Level 2. Our derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility, and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. We consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data, in our assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

(Dollars in millions, unless otherwise noted)

Disclosed below is detail surrounding our significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. The Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. We utilize various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties, and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, we discount future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and our own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.33 and $0.53 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

See Note 16 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

The following table presents the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value as of December 31, 2021	Fair Value as of December 31, 2020	Valuation Technique	Unobservable Input	2021 Range & Arithmetic Average				2020 Range & Arithmetic Average			
Mark-to-market derivatives— Economic hedges(a)(b)	$ (66)	$ 245	Discounted Cash Flow	Forward power price	$8.86	-	$481	$55	$2.25	-	$163	$30
				Forward gas price	$1.69	-	$17	$3.50	$1.57	-	$7.88	$2.59
			Option Model	Volatility percentage	24%	-	284%	56%	11%	-	237%	32%

(a) The valuation techniques, unobservable inputs, ranges, and arithmetic averages are the same for the asset and liability positions.
(b) The fair values do not include cash collateral (received) posted on level three positions of $(34) million and $162 million as of December 31, 2021 and December 31, 2020, respectively.

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of our commodity derivatives are forward commodity prices and for options is price volatility.

(Dollars in millions, unless otherwise noted)

Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

19. Commitments and Contingencies

Commercial Commitments. Commercial commitments as of December 31, 2021, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2022	2023	2024	2025	2026	2027 and beyond
Letters of credit	$ 2,380	$ 2,279	$ 101	$ —	$ —	$ —	$ —
Surety bonds[a]	899	882	17	—	—	—	—
Total commercial commitments	$ 3,279	$ 3,161	$ 118	$ —	$ —	$ —	$ —

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

Nuclear Insurance

We are subject to liability, property damage and other risks associated with major incidents at any of our nuclear stations. We have mitigated our financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2021, the current liability limit per incident is $13.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors at least once every five years with the last adjustment effective November 1, 2018. In accordance with the Price-Anderson Act, we maintain financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $13.1 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Our share of this secondary layer would be approximately $2.8 billion, however any amounts payable under this secondary layer would be capped at $413 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.5 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, we executed an Indemnity Agreement pursuant to which we agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. See Note 21 — Variable Interest Entities for additional information on our operations relating to CENG.

We are required each year to report to the NRC the current levels and sources of property insurance that demonstrates we possess sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which we are a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years, NEIL has made distributions to its members. Our portion of the annual distribution declared by NEIL is estimated to be $113 million for 2021, and was $75 million and $136 million for 2020 and 2019, respectively. The distributions were recorded as a reduction to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and we cannot predict the level of future assessments, if any. The current maximum aggregate annual retrospective premium obligation for us is approximately $229 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides “all risk” property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which we are required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, we are unable to predict the timing of the availability of insurance proceeds to us and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by us will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For our insured losses, we are self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by us. Any such losses could have a material adverse effect on our financial statements.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, we are a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from our nuclear generating stations. In accordance with the NWPA and the Standard Contracts, we had previously paid the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. Due to the lack of a viable disposal program, the DOE reduced the SNF disposal fee to zero in May 2014. Until a new fee structure is in effect, we will not accrue any further costs related to SNF disposal fees. This fee may be adjusted prospectively to ensure full cost recovery.

We currently assume the DOE will begin accepting SNF in 2035 and use that date for purposes of estimating the nuclear decommissioning AROs. The SNF acceptance date assumption is based on management’s estimate of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage.

The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance has been, and is expected to remain, delayed significantly. In August 2004, we and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse us, subject to certain damage limitations based on the extent of the government’s breach, for costs associated with storage of SNF at our nuclear stations pending the DOE’s fulfillment of its obligations. Calvert Cliffs, Ginna and Nine Mile Point each have separate settlement agreements in place with the DOE which were extended during 2020 to provide for the reimbursement of SNF storage costs through December 31, 2022. FitzPatrick also has a separate settlement agreement in place with the DOE that was established in 2021 to provide for reimbursement of SNF storage costs through December 31, 2022. We submit annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

(Dollars in millions, unless otherwise noted)

Under the settlement agreements, we received total cumulative cash reimbursements of $1,492 million through December 31, 2021 for costs incurred. After considering the amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek, we received net cumulative cash reimbursements of $1,294 million. As of December 31, 2021 and 2020, the amount of SNF storage costs for which reimbursement has been or will be requested from the DOE under the DOE settlement agreements is as follows:

	December 31, 2021	December 31, 2020
DOE receivable - current[(a)]	$ 241	$ 129
DOE receivable - noncurrent[(b)]	85	70
Amounts owed to co-owners[(c)]	(35)	(23)

____
(a) Recorded in Other accounts receivable.
(b) Recorded in Deferred debits and other assets, other.
(c) Recorded in Other accounts receivable. Represents amounts owed to the co-owners of Peach Bottom, Quad Cities, and Nine Mile Point Unit 2 generating facilities.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The below table outlines the SNF liability recorded as of December 31, 2021 and 2020:

	December 31, 2021	December 31, 2020
Former ComEd units[(a)]	$ 1,083	$ 1,082
Fitzpatrick[(b)]	127	126
Total SNF Obligation	$ 1,210	$ 1,208

____
(a) ComEd previously elected to defer payment of the one-time fee of $277 million for its units, with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. The unfunded liabilities for SNF disposal costs, including the one-time fee, were transferred to us as part of Exelon's 2001 corporate restructuring.
(b) A prior owner of FitzPatrick elected to defer payment of the one-time fee of $34 million, with interest to the date of payment, for the FitzPatrick unit. As part of the FitzPatrick acquisition on March 31, 2017, we assumed a SNF liability for the DOE one-time fee obligation with interest related to FitzPatrick along with an offsetting asset, included in Other deferred debits and other assets, for the contractual right to reimbursement from NYPA, a prior owner of FitzPatrick, for amounts paid for the FitzPatrick DOE one-time fee obligation.

Interest for our SNF liabilities accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect for calculation of the interest accrual at December 31, 2021 was 0.051% for the deferred amount transferred from ComEd and 0.041% for the deferred FitzPatrick amount.

The following table summarizes sites for which we do not have an outstanding SNF Obligation:

Description	Sites
Fees have been paid	Former PECO units, Clinton and Calvert Cliffs
Outstanding SNF Obligation remains with former owners	Nine Mile Point, Ginna and TMI

Environmental Remediation Matters

General. Our operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, we are generally liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease a number of real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, we are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, we cannot reasonably estimate whether we will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by us, environmental agencies or others. Additional costs could have a material, unfavorable impact on our financial statements.

As of December 31, 2021 and 2020, we had accrued undiscounted amounts of $120 million and $121 million, respectively, for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities in the Consolidated Balance Sheets.

Cotter Corporation. The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to us. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Our investigation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision Amendment (RODA) for the selection of a final remedy. The RODA modified the remedy previously selected by EPA in its 2008 Record of Decision (ROD). While the ROD required only that the radiological materials and other wastes at the site be capped, the 2018 RODA requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The RODA also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed in late 2024. In March 2019, the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. On October 8, 2019, Cotter (our indemnitee) provided a non-binding good faith offer to conduct, or finance, a portion of the remedy, subject to certain conditions. The total estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred collectively by the PRPs in fully executing the remedy, is approximately $290 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. We have determined that a loss associated with the EPA's partial excavation and enhanced landfill cover remedy is probable and have recorded a liability, included in the total amount as discussed above, that reflects management's best estimate of Cotter's allocable share of the ultimate cost. Given the joint and several nature of this liability, the magnitude of our ultimate liability will depend on the actual costs incurred to implement the required remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Cotter's associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact on our financial statements.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, we do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on our financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial Investigation Feasibility Study (RI/FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. We estimate the undiscounted cost for the groundwater RI/FS to be approximately $40 million. We determined a loss associated with the RI/FS is probable and have recorded a liability, included in the total amount as discussed above, that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time we cannot predict the likelihood, or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on our financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's (now our) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP (Formerly Utilized Sites Remedial Action Program). Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until February 28, 2022 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately $90 million from all the PRPs and has directed that the PRPs must submit a good faith joint proposed settlement offer. In December 2021, a good faith offer was submitted to the government and negotiations are expected to commence in the first quarter of 2022. We have determined that a loss associated with this matter is probable under our indemnification agreement with Cotter and have recorded an estimated liability, included in the total amount as discussed above.

Benning Road Site. In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility, which was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now us, pursuant to Exelon's 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, we and Pepco issued a draft "final" RI report which DOEE approved on February 3, 2020. We and Pepco are developing a FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by September 16, 2022. After completion and approval of the FS, DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. We have determined that a loss associated with this matter is probable and have accrued an estimated liability, included in the total amount as discussed above.

Pursuant to the terms of the Separation agreement, all future liabilities associated with this matter were transferred to Exelon on February 1, 2022, except for the continuing obligation to fund 5% for the completion of the remedial investigation and feasibility study and any other requirements of the 2011 Consent Decree.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims. We maintain a reserve for claims associated with asbestos-related personal injury actions at certain facilities that are currently owned by us or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2021 and 2020, we recorded estimated liabilities of approximately $81 million and $89 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2021, approximately $17 million of this amount related to 211 open claims presented to us, while the remaining $64 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, we monitor actual experience against the number of forecasted claims to be received and expected claim payments and evaluate whether adjustments to the estimated liabilities are necessary.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages. Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. See Note 3 — Regulatory Matters for additional information.

Various lawsuits have been filed against us since March 2021 related to these events, including:

- On March 5, 2021, we, along with more than 160 power generators and transmission and distribution companies, were sued by approximately 160 individually named plaintiffs, purportedly on behalf of all Texans who allegedly suffered loss of life or sustained personal injury, property damage or other losses as a result of the weather events. The plaintiffs allege that the defendants failed to properly prepare for the cold weather and failed to properly conduct their operations, seeking compensatory as well as punitive damages. On April 26, 2021, another multi-plaintiff lawsuit was filed on behalf of approximately 90 plaintiffs against more than 300 defendants, including us, involving similar allegations of liability and claims of personal injury and property damage. Since March 2021, approximately 60 additional lawsuits, naming multiple defendants including us, were filed by individual or multiple plaintiffs in different Texas counties, all arising out of the February weather events. These additional lawsuits allege wrongful death, property damage, or other losses. Co-defendants in these lawsuits include ERCOT, transmission and distribution utilities and other generators. On December 28, 2021, approximately 130 insurance companies which insured Texas homeowners and businesses filed a subrogation lawsuit against multiple defendants alleging that defendants were at fault for the energy failure that resulted from the winter storm, causing significant property damage to the insureds. Additionally, as of January 28, 2022, we have been added to approximately 80 additional wrongful death, personal injury, and property damage lawsuits through the Multi-District-Litigation (MDL) pending in Texas state court. The MDL now includes all of the above-described Texas state court matters. We dispute liability and deny that we are responsible for any of plaintiffs' alleged claims and are vigorously contesting them. No loss contingencies have been reflected in the consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.
- On March 22, 2021, an LDC filed a lawsuit in Missouri federal court against us for breach of contract and unjust enrichment, seeking damages of approximately $40 million. The plaintiff claims that we failed to deliver gas to our customers in February of 2021, causing the plaintiff to incur damages by forcing it to purchase gas for our customers and by our refusal to pay the resulting penalties. On March 26, 2021, we filed a complaint with the MPSC against the LDC to void the OFO penalties, or alternatively to grant a waiver or variance from the tariff requirements, to prohibit the LDC from billing or otherwise attempting to collect from us or any Missouri customer any portion of the penalties claimed by the LDC until the resolution of the complaint, and to prohibit the LDC from taking any retaliatory measure, including termination of service. On September 1, 2021, the MPSC consolidated our complaint with two other similar complaints from other companies. On January 4, 2022, the court denied our motion to dismiss, but in the alternative granted its motion to stay pending MPSC resolution of our complaint. The MPSC has scheduled an evidentiary hearing for the three consolidated complaint cases in April 2022. Based on the penalty provisions within the tariff that was in effect at the relevant time, we have recorded a liability of approximately $40 million as of December 31, 2021.

General. We are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. We maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

20. Stock-Based Compensation Plans

Our employees were granted stock-based awards through the Exelon LTIP as of December 31, 2021, which primarily includes performance share awards, restricted stock units, and stock options. We also grant cash awards. Performance share awards are typically settled 50% in common stock and 50% in cash at the end of a three-year performance period, subject to certain ownership thresholds that, if met, may result in cash settlement of the entire award. The following table does not include expense related to cash awards granted as they are not considered stock-based compensation plans under the applicable authoritative guidance.

The following table presents the stock-based compensation expense included in the Consolidated Statements of Operations and Comprehensive Income:

(Dollars in millions, unless otherwise noted)

	Year Ended December 31,		
	2021	2020	2019
Total stock-based compensation expense included in operating and maintenance expense	$ 47	$ 27	$ 37
Income tax benefit	(12)	(7)	(10)
Total after-tax stock-based compensation expense	$ 35	$ 20	$ 27

Impact of Separation from Exelon

Effective February 1, 2022, we established our own LTIP and began granting cash and stock-based awards that primarily include performance share awards and restricted stock units. The existing, unvested cash and stock-based awards issued through the Exelon LTIP were modified in connection with the separation to align with our performance metrics and maintain an equivalent value immediately before and after separation.

21. Variable Interest Entities

At December 31, 2021 and 2020, we consolidated several VIEs or VIE groups for which we are the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which we do not have the power to direct the entities' activities and, accordingly, we were not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements as of December 31, 2021 and 2020. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnotes to the table below, are such that creditors, or beneficiaries, do not have recourse to our general credit.

(Dollars in millions, unless otherwise noted)

	December 31, 2021	December 31, 2020
Cash and cash equivalents	$ 35	$ 98
Restricted cash and cash equivalents	48	44
Accounts receivable		
Customer	24	148
Other	6	36
Inventories, net		
Materials and supplies	14	244
Assets held for sale[(a)]	—	101
Other current assets	405	691
Total current assets	532	1,362
Property, plant and equipment, net	2,027	5,803
Nuclear decommissioning trust funds	—	3,007
Other noncurrent assets	215	291
Total noncurrent assets	2,242	9,101
Total assets[(b)]	$ 2,774	$ 10,463
Long-term debt due within one year	$ 70	$ 68
Accounts payable	10	81
Accrued expenses	21	70
Liabilities held for sale[(a)]	—	16
Other current liabilities	1	9
Total current liabilities	102	244
Long-term debt	822	889
Asset retirement obligations	151	2,318
Other noncurrent liabilities	3	129
Total noncurrent liabilities	976	3,336
Total liabilities[(c)]	$ 1,078	$ 3,580

(a) We entered into an agreement for the sale of a significant portion of our solar business. As a result of this transaction, in the fourth quarter of 2020, we reclassified the consolidated VIEs' solar assets and liabilities as held for sale. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the sale of the solar business.

(b) Our balances include unrestricted assets for current unamortized energy contract assets of $23 million and $22 million, disclosed within other current assets in the table above, noncurrent unamortized energy contract assets of $202 million and $249 million, disclosed within other noncurrent assets in the table above, Assets held for sale of $0 million and $9 million, and other unrestricted assets of $0 million and $1 million, as of December 31, 2021 and 2020, respectively.

(c) Our balances include liabilities with recourse of $1 million and $8 million as of December 31, 2021 and 2020, respectively.

(Dollars in millions, unless otherwise noted)

As of December 31, 2021 and 2020, our consolidated VIEs included the following:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are the primary beneficiary:
CENG - A joint venture between us and EDF. We had a 50.01% equity ownership in CENG as of December 31, 2020 and acquired EDF's 49.99% equity interest on August 6, 2021 resulting in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. See additional discussion below.	Disproportionate relationship between equity interest and operational control as a result of the NOSA described further below.	We conduct the operational activities.
CRP - A collection of wind and solar project entities. We have a 51% equity ownership in CRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Bluestem Wind Energy Holdings, LLC - A Tax Equity structure which is consolidated by CRP. We have a noncontrolling interest.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
Antelope Valley - A solar generating facility, which is 100% owned by us. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	We conduct all activities.
Equity investment in distributed energy company - We have a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE. (See Unconsolidated VIEs disclosure below). We fully impaired this investment in the third quarter of 2019. Refer to Note 12 — Asset Impairments for additional information.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We conduct the operational activities.
NER - A bankruptcy remote, special purpose entity which is 100% owned by us, which purchases certain of our customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. Refer to Note 6 —Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	We conduct all activities.

CENG - On April 1, 2014, we, CENG, and subsidiaries of CENG executed the NOSA pursuant to which we conduct all activities associated with the operations of the CENG fleet and provide corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of our nuclear fleet, subject to the CENG member rights of EDF.

On November 20, 2019, we received notice of EDF's intention to exercise the put option to sell us its equity interest in CENG and the put automatically exercised on January 19, 2020. On August 6, 2021, we entered into a settlement agreement with EDF pursuant to which we purchased EDF's equity interest in CENG and resulted in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

We provide the following support to CENG:

- We executed an Indemnity Agreement pursuant to which we agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees our obligations under this Indemnity Agreement and will continue to do so post-separation, however, any calls on this guarantee would require us to reimburse Exelon under the terms of the Separation Agreement. See Note 19 — Commitments and Contingencies and Note 24 — Separation from Exelon for more details.

- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries. Both the support agreement and guarantee terminated upon separation and we executed new support agreements for the benefit of each CENG subsidiary plant owner.

Prior to August 6, 2021, we and EDF shared in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance. Following the execution of the settlement agreement, EDF no longer shares in the obligation.

CRP - CRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by CRP. While we or CRP own 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that the wholly owned solar and wind entities are VIEs because the entities' customers absorb price variability from the entities through fixed price power and/or REC purchase agreements. Additionally, for the wind entities that have minority interests, it has been determined that these entities are VIEs because the governance rights of some investors are not proportional to their financial rights. We are the primary beneficiary of these solar and wind entities that qualify as VIEs because we control operations and direct all activities of the facilities. There is limited recourse to us related to certain solar and wind entities.

In 2017, our interests in CRP were contributed to and are pledged for the CR non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements for additional information.

Unconsolidated VIEs

Our variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in the Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to our involvement with the VIEs are predominantly related to working capital accounts and generally represent the amounts owed by, or owed to, us for the deliveries associated with the current billing cycles under the commercial agreements.

As of December 31, 2021 and 2020, we had significant unconsolidated variable interests in several VIEs for which we were not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

(Dollars in millions, unless otherwise noted)

The following table presents summary information about our significant unconsolidated VIE entities:

	December 31, 2021			December 31, 2020		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 772	$ 372	$ 1,144	$ 777	$ 401	$ 1,178
Total liabilities[(a)]	80	216	296	61	223	284
Our ownership interest in VIE[(a)]	—	139	139	—	157	157
Other ownership interests in VIE[(a)]	692	17	709	716	21	737

(a) These items represent amounts on the unconsolidated VIE balance sheets, not in the Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. We do not have any exposure to loss as we do not have a carrying amount in the equity investment VIEs as of December 31, 2021 and 2020.

As of December 31, 2021 and 2020, the unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
Equity investments in distributed energy companies - 1) We have a 90% equity ownership in a distributed energy company. 2) We, via a consolidated VIE, have a 90% equity ownership in another distributed energy company (See Consolidated VIEs disclosure above). We fully impaired this investment in the third quarter of 2019. Refer to Note 12 — Asset Impairments for additional information.	Similar structures to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	We do not conduct the operational activities.
Energy Purchase and Sale agreements - We have several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	We do not conduct the operational activities.

22. Supplemental Financial Information

Supplemental Statement of Operations Information

The following tables provide additional information about material items recorded in the Consolidated Statements of Operations and Comprehensive Income.

	Taxes other than income taxes		
	For the Years Ended December 31,		
	2021	2020	2019
Gross receipts[(a)]	$ 99	$ 99	$ 112
Property	268	265	274
Payroll	109	113	115

(a) Represent gross receipts taxes related to our retail operations. The offsetting collection of gross receipts taxes from customers is recorded in revenues in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

	Other, net		
	For the Years Ended December 31,		
	2021	2020	2019
Decommissioning-related activities:			
Net realized income on NDT funds[(a)]			
Regulatory Agreement Units	$ 817	$ 185	$ 297
Non-Regulatory Agreement Units	449	160	363
Net unrealized gains on NDT funds			
Regulatory Agreement Units	351	724	795
Non-Regulatory Agreement Units	209	391	411
Regulatory offset to NDT fund-related activities[(b)]	(917)	(729)	(876)
Decommissioning-related activities	909	731	990
Net unrealized (losses) gains from equity investments[(c)]	(160)	186	—

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(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of income taxes related to all NDT fund activity for those units. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning and the contractual offset suspension for the Byron units.
(c) Net unrealized (losses) gains from equity investments that became publicly traded in the fourth quarter of 2020 and the first half of 2021.

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Consolidated Statements of Cash Flows.

	Depreciation, amortization and accretion		
	For the Years Ended December 31,		
	2021	2020	2019
Property, plant, and equipment[(a)]	$ 2,954	$ 2,070	$ 1,485
Amortization of intangible assets, net[(a)]	49	53	50
Amortization of energy contract assets and liabilities[(b)]	31	30	21
Nuclear fuel[(c)]	992	983	1,016
ARO accretion[(d)]	514	500	491
Total depreciation, amortization, and accretion	$ 4,540	$ 3,636	$ 3,063

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(a) Included in Depreciation and amortization in the Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Operating revenues or Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.
(d) Included in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

	Cash paid (refunded) during the year:		
	For the Years Ended December 31,		
	2021	2020	2019
Interest (net of amount capitalized)	$ 275	$ 331	$ 373
Income taxes (net of refunds)	426	70	(44)

	Other non-cash operating activities:		
	For the Years Ended December 31,		
	2021	2020	2019
Pension and non-pension postretirement benefit costs	$ 123	$ 115	$ 135
Allowance for credit losses	32	17	31
Other decommissioning-related activity[(a)]	(946)	(659)	(506)
Energy-related options[(b)]	125	104	22
Severance costs	(73)	90	—
Provision for excess and obsolete inventory	(13)	128	—
Amortization of operating ROU asset	119	155	172

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning and for additional information on the contractual offset suspension for the Byron units.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

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

	December 31, 2021	December 31, 2020	December 31, 2019	December 31, 2018
Cash and cash equivalents	$ 504	$ 226	$ 303	$ 750
Restricted cash and cash equivalents	72	89	146	153
Cash, restricted cash, and cash equivalents - Held for Sale	—	12	—	—
Total cash, restricted cash, and cash equivalents	$ 576	$ 327	$ 449	$ 903

(Dollars in millions, unless otherwise noted)

Supplemental Balance Sheet Information

The following tables provide additional information about material items recorded in the Consolidated Balance Sheets.

	Investments	
	December 31, 2021	December 31, 2020
Equity method investments:		
Other equity method investments	$ 62	$ 65
Other investments:		
Employee benefit trusts and investments[(a)]	72	61
Equity investments without readily determinable fair values	33	55
Other available for sale debt security investments	7	3
Total investments	$ 174	$ 184

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(a) Debt and equity security investments are recorded at fair market value.

	Accrued expenses	
	December 31, 2021	December 31, 2020
Compensation-related accruals[(a)]	$ 356	$ 426

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(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

23. Related Party Transactions

Prior to completion of the separation on February 1, 2022, we engaged in transactions with affiliates of Exelon in the normal course of business, these affiliate transactions are summarized in the tables below. After February 1, 2022, all transactions with Exelon or its affiliates are no longer related party transactions.

Operating revenues from affiliates

The following table presents our Operating revenues from affiliates:

	For the Years Ended December 31,		
	2021	2020	2019
ComEd[(a)]	$ 376	$ 330	$ 369
PECO[(b)]	196	190	158
BGE[(c)]	236	315	289
PHI	366	367	353
Pepco[(d)]	270	279	264
DPL[(e)]	79	75	70
ACE[(f)]	17	13	19
Other	14	9	3
Total operating revenues from affiliates	$ 1,188	$ 1,211	$ 1,172

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(a) We have an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. We also sell RECs and ZECs to ComEd.
(b) We provide electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, we have a ten-year agreement with PECO to sell solar AECs.
(c) We provide a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.

(Dollars in millions, unless otherwise noted)

(d) We provide electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
(e) We provide a portion of DPL's energy requirements under its MDPSC and DEPSC approved market-based SOS commodity programs.
(f) We provide electric supply to ACE under contracts executed through ACE's competitive procurement process.

Service Company Costs for Corporate Support

We received a variety of corporate support services from Exelon. Through its business services subsidiary, BSC, Exelon provided support services at cost, including legal, human resources, financial, information technology, and supply management services. The costs of BSC are directly charged or allocated to us. Certain of these services will continue after the separation and are covered by the Transition Services Agreement. See Note 24 — Separation from Exelon for additional information.

The following table presents the service company costs allocated to us:

Operating and maintenance from affiliates			Capitalized costs		
For the Years Ended December 31,			For the Years Ended December 31,		
2021	2020	2019	2021	2020	2019
$ 588	$ 552	$ 570	$ 129	$ 54	$ 66

Current Receivables from/Payables to affiliates

The following tables present Current receivables from affiliates and Current payables to affiliates:

	December 31, 2021		December 31, 2020	
	Receivables from affiliates:	Payables to affiliates:	Receivables from affiliates:	Payables to affiliates:
ComEd	$ 84	$ 13	$ 78	$ 13
PECO	30	—	17	—
BGE	4	—	11	—
Pepco	20	—	13	—
DPL	4	—	3	—
ACE	7	—	6	—
BSC	—	102	—	72
Other	11	16	25	22
Total	$ 160	$ 131	$ 153	$ 107

Noncurrent Payables to affiliates

We have Noncurrent payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 10 — Asset Retirement Obligations for additional information.

The following table presents our noncurrent payables to ComEd and PECO which are recorded as noncurrent payables to affiliates:

	As of December 31,	
	2021	2020
ComEd	$ 2,760	$ 2,541
PECO	597	475

24. Separation from Exelon

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the competitive generation and customer-facing businesses of Constellation into a stand-alone publicly traded company ("the separation"). On February 25, 2021, Exelon filed applications with FERC, NYPSC, and NRC seeking approvals for the separation. A private letter ruling from the IRS confirming the tax-free treatment of the separation was received on September 23, 2021. Exelon received approval from FERC on August 24, 2021, and the NRC on November 16, 2021.

On December 16, 2021 the NYPSC authorized the separation and accepted the terms of a Joint Proposal dated November 23, 2021, by and between Exelon, Constellation, the Staff of the New York State Department of Public Service, the New York State Office of the Attorney General, the Alliance for a Green Economy, and LIPA. The terms of the Joint Proposal, which became binding upon closing of the separation, included, among other items, specific provisions for the future retirement of our three nuclear power plant sites in New York, a $15 million contribution to the NDT for NMP Unit 2, and various financial assurance provisions for each unit through the completion of site restoration. See Note 10 — Asset Retirement Obligations for additional information.

In order to govern the ongoing relationships between us after the separation, and to facilitate an orderly transition, we entered into several agreements with Exelon, including the following:

- Separation Agreement – sets forth the principal actions to be taken in connection with the separation, including the transfer of assets and assumption of liabilities and establishes certain rights and obligations between us following the distribution
- Transition Services Agreement (TSA) – governs all matters relating to the provision of services between us on a transitional basis, in addition to providing us with certain services for an expected period of two-years, provided that certain services may be longer than the term and services may be extended with approval from both parties. The services include support for information technology, accounting, finance, human resources, security, and various other administrative and operational services
- Employee Matters Agreement (EMA) – addresses certain employment, compensation and benefits matters, including the allocation of employees between us and the allocation and treatment of certain assets and liabilities relating to our employees and former employees
- Tax Matters Agreement - governs the respective rights, responsibilities, and obligations between us with respect to all tax matters (excluding employee related taxes covered under EMA), in addition to certain restrictions which generally prohibit us from taking or failing to take any action in the two-year period following the distribution that would prevent the distribution from qualifying as tax-free for U.S. federal income tax purposes, including limitations on our ability to pursue certain equity issuances, strategic transactions, repurchases or other transactions

Pursuant to the Separation Agreement, we received a cash contribution of $1.75 billion from Exelon on January 31, 2022, the proceeds of which were used to settle $258 million of an intercompany loan from Exelon and $200 million of short-term debt outstanding prior to separation, in addition to a $192 million contribution to our pension plans. We also entered into two new five-year credit facility agreements providing $4.5 billion of capacity. See Note 17 — Debt and Credit Agreements and Note 15 — Retirement Benefits for additional information on these separation related items.

On February 1, 2022, Exelon completed the separation through a pro-rata distribution of all of the outstanding shares of our common stock, no par value, for every three shares of Exelon common stock held on January 20, 2022, the record date of the distribution. We are now an independent, publicly traded company listed on the NASDAQ exchange under the symbol "CEG", and regular-way trading began on February 2, 2022. Exelon no longer retains any ownership interest in CEG Parent or Constellation.

Prior to completion of the separation, our financial statements include certain transactions with affiliates of Exelon, which are disclosed as related party transactions. After February 1, 2022, all transactions with Exelon or its affiliates are no longer related party transactions. See Note 23 — Related Party Transactions for additional information.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

All Registrants - Disclosure Controls and Procedures

During the fourth quarter of 2021, our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in periodic reports that we file with the SEC. These disclosure controls and procedures have been designed to ensure that (a) information, including information related to our consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to our management, including our principal executive officer and principal financial officer, by other employees as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2021, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Constellation - Changes in Internal Control Over Financial Reporting

There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2021 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

CEG Parent - Internal Control Over Financial Reporting

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Constellation - Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2021. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2021 and, therefore, concluded that Constellation’s internal control over financial reporting was effective. Management’s Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

ITEM 9B. OTHER INFORMATION

None.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable

PART III

Constellation Energy Generation, LLC meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to Constellation are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Information about our Executive Officers as of February 25, 2022

Name	Age	Position	Period
Dominguez, Joseph	59	President and Chief Executive Officer	2022 - Present
		President and Chief Executive Officer, Exelon Generation Company, LLC	2021 - 2022
		Chief Executive Officer, ComEd	2018 - 2021
		Executive Vice President, Governmental and Regulatory Affairs and Public Policy, Exelon	2012 - 2018
Eggers, Daniel	46	Executive Vice President and Chief Financial Officer	2022 - Present
		Executive Vice President and Chief Financial Officer, Exelon Generation Company, LLC	2021 - 2022
		Senior Vice President of Corporate Finance, Exelon	2018 - 2021
		Senior Vice President of Investor Relations, Exelon	2016 - 2018
Barrón, Kathleen	51	Executive Vice President and Chief Strategy Officer	2022 - Present
		Executive Vice President and Chief Strategy Officer, Exelon Generation Company, LLC	2021 - 2022
		Executive Vice President of Government and Regulatory Affairs, Exelon	2018 - 2021
		Senior Vice President, Competitive Market Policy, Exelon	2012 - 2018
Hanson, Bryan C.	56	Executive Vice President and Chief Generation Officer	2022 - Present
		Executive Vice President and Chief Generation Officer, Exelon Generation Company, LLC	2020 - 2022
		President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation Company, LLC	2015 - 2020
Koehler, Michael R.	55	Executive Vice President and Chief Administration Officer	2022 - Present
		Executive Vice President and Chief Administration Officer, Exelon Generation Company, LLC	2021 - 2022
		Senior Vice President and Chief Information and Chief Digital Officer, Exelon	2016 - 2021
McHugh, James	50	Executive Vice President and Chief Commercial Officer	2022 - Present
		Executive Vice President and Chief Commercial Officer, Exelon Generation Company, LLC	2021 - 2022
		Executive Vice President, Exelon; Chief Executive Officer, competitive retail and commodities business, Exelon	2018 - 2021
		Senior Vice President, Portfolio Management and Strategy, competitive retail and commodities business, Exelon	2016 - 2018
Dardis, David	49	Executive Vice President and General Counsel	2022 - Present
		Executive Vice President and General Counsel, Exelon Generation Company, LLC	2021 - 2022
		Senior Vice President and General Counsel, Exelon Generation Company, LLC	2020 - 2021
		Senior Vice President and General Counsel, competitive retail and commodities business, Exelon	2016 - 2020
Bauer, Matthew	45	Senior Vice President and Controller	2022 - Present
		Vice President and Controller, Exelon Generation Company, LLC	2016 - 2022

Information about our Board of Directors as of February 25, 2022

Name	Age	Committee Appointment
Joseph Dominguez	59	N/A
Yves de Balmann	75	Compensation (Chair), Corporate Governance
Laurie Brlas	64	Audit and Risk (Chair)
Rhonda Ferguson	52	Audit and Risk, Nuclear Oversight
Bradley Halverson	61	Compensation, Corporate Governance
Charles Harrington	63	Corporate Governance, Nuclear Oversight
Julie Holzrichter	54	Audit and Risk, Compensation
Ashish Khandpur	54	Compensation, Corporate Governance
Robert Lawless	75	Corporate Governance (Chair)
John Richardson	61	Audit and Risk, Nuclear Oversight (Chair)

Yves de Balmann has served on our Board since January 2022. He has extensive experience in corporate finance, including the derivatives and capital markets as well as industry experience as a former director of Exelon from 2012 to 2022 as well as Constellation Energy Group prior to its merger with Exelon in 2012. His deep knowledge of strategic planning, compensation, governance, and investor insights will provide significant value to the Company Board. Mr. de Balmann currently serves as Executive Partner at Bridge Growth Partners, a private equity firm focusing on technology and financial services companies, and previously served as Co-Chairman of Bregal Investments LP, a private equity investing firm, from 2002 to 2012. He is also currently on the Board of Directors of ESI Group, a virtual prototyping software company.

Laurie Brlas has served on our Board since January 2022, and previously served on the Exelon Board from 2018 to 2022. She has proven leadership skills derived from her significant experience as an executive leader at global, capital-intensive companies, and operations and finance experience in the natural resources industry in addition to her background in financial and governance matters that will bring valuable insights to the Company Board. Ms. Brlas served as Executive Vice President and Chief Financial Officer of Newmont Mining Corporation, a global mining company, from 2013 to 2016. Prior to that, she served in multiple senior positions between 2006 and 2013, ultimately as Executive Vice President and President, Global Operations, with Cleveland-Cliffs, Inc., a company specializing in the mining, benefication and pelletizing of iron ore. Ms. Brlas currently serves on the Boards of Directors of Albemarle Corporation (since 2017), Graphic Packaging Holding Company (since 2019) and Autoliv, Inc. (since 2020). She previously served on the Boards of Directors of Calpine Corporation (2016 to 2018) and Perrigo Company plc (2003 to 2019).

Rhonda Ferguson has served on our board since January 2022. She joined Allstate Corporation in 2020 and serves as its Executive Vice President, Chief Legal Officer, General Counsel and Secretary. Prior to joining Allstate, she served as Executive Vice President, Chief Legal Officer and Secretary for Union Pacific Corporation from 2016 to 2020, and as Vice President, Secretary and Chief Ethics Officer of First Energy Corp. from 2007 to 2016. Ms. Ferguson serves on the boards for the RAND Institute for Civil Justice and Girls Inc. of Chicago. She has proven leadership skills derived from her significant experience as an executive leader at large, highly regulated companies, and her background in legal, regulatory, compliance and governance matters will bring valuable insights to the Board.

Bradley Halverson has served on our Board since January 2022. He is the former Group President and Chief Financial Officer of Caterpillar Inc., the world's leading manufacturer of construction and mining equipment, diesel and gas engines, turbines and locomotives. Prior to serving as Group President and CFO from 2013 to 2018, he held a series of positions with increasing responsibility during his 30-year tenure with the Fortune 100 company, including vice president, Financial Services; corporate controller, Global Finance & Strategic Services; and corporate business development manager, Corporate Services, among others since joining the company in 1988. Mr. Halverson currently serves on the boards of Sysco Corporation, Lear Corporation and Satellogic Inc. In addition, he serves on the board of Easter Seals Central Illinois, Inc. He previously served as a director for Custom Truck One Source from 2018-2021. Mr. Halverson's deep expertise in accounting, financial reporting and corporate finance, and his leadership experience in the areas of executive leadership and management, corporate strategy development, mergers and acquisitions, risk management, information technology systems oversight and international business will provide the Board with critical perspectives on strategic, financial and other public company issues.

Charles Harrington has served on our Board since January 2022. He is the chairman and former CEO of Parsons Corporation, a technology services company in the global defense, intelligence and critical infrastructure markets. He served as Chairman and CEO of the company from 2008 to 2021, following previous roles within the company, including Executive Vice President, CFO and Treasurer; President, Commercial Technology Group; and president, Communications Technology Group, from 1999 to 2002, among others. In addition to serving as chairman of Parsons, Mr. Harrington serves on the boards of J.G. Boswell Company and California Polytechnic State University San Luis Obispo Foundation. He previously served on the board of The AES Corporation from 2013 to 2020. Mr. Harrington's extensive leadership experience in operations, finance and business development will provide significant value to the Board.

Julie Holzrichter has served on our Board since January 2022. She currently serves as chief operating officer of CME Group, the world's leading derivatives marketplace. Prior to being appointed to her current role in 2014, she held various roles of increasing responsibility, including senior managing director of Global Operations; managing director, Global Operations; and director, Operations, among others, having led the integration of global operations for a number of multi-billion-dollar mergers and acquisitions throughout her tenure. Ms. Holzrichter serves on the board of the National Futures Association and is a member of the Futures Industry Association, ChicagoFirst and the CME Group Women's Initiative Network. Her extensive experience leading the operations of CME Group's market operations, global command center, trading floor operations, global market solutions and services, data centers and critical infrastructure, global security, business continuity and crisis management will provide valuable insight to the Board.

Ashish Khandpur has served on our Board since January 2022. He currently serves as President of the Transportation & Electronics business group for 3M Company, a Fortune 100 global corporation operating in the fields of transportation, electronics, worker safety, health care, consumer goods and industry. During his 26-year career with 3M, he has held a series of roles with increasing responsibility, including Executive Vice President, Transportation & Electronics; Executive Vice President, Electronics & Energy; and Senior Vice President, Research & Development and Chief Technology Officer, among other roles. Mr. Khandpur's extensive engineering background and deep experience in global operations and research and development will provide an invaluable perspective to the Board.

Robert Lawless has served on our Board since January 2022. He has deep executive leadership, strategic planning, and corporate governance experience, as well as industry experience as a former director of Exelon from 2012 to 2022 as well as Constellation Energy Group prior to its merger with Exelon in 2012 and will provide the Company Board with critical perspectives on governance and other public company issues. Mr. Lawless served in numerous senior level positions over a more than thirty-year career with McCormick & Company, Inc., a global food manufacturing company, including as President from 1996 to 2006, as Chief Executive Officer from 1997 to 2008, and as Chairman from 1997 until 2009.

Admiral John Richardson has served on our Board since January 2022 and previously served on the Exelon Board from 2019 to 2022. His experience leading the U.S. Navy as well as his expertise in nuclear oversight and operational excellence will bring invaluable knowledge to our Board. Admiral Richardson served in various senior positions during his thirty-seven-year career with the U.S. Navy, including as Chief of Naval Operations from 2015 to 2019, Director of Naval Reactors, commander of U.S. Submarine Forces, and Director of Strategy and Policy at the U.S. Joint Forces Command. He currently serves as a director of The Boeing Company (since 2019) and BWX Technologies, Inc. (since 2020). Admiral Richardson also currently serves as a director of Sparkcognition Government Systems, a developer of A.I. solutions for multiple industries including energy, defense and finance, and of the Center for New American Security, a bipartisan think tank focused on national security, including issues around energy and geopolitics.

Our Corporate Governance

Board Diversity. Our Corporate Governance Committee is responsible for reviewing with the Board of Directors, on an annual basis, the appropriate characteristics, skills and experience required for the Board as a whole. In evaluating and recommending the suitability of candidates (both new candidates and current members) for election, the following factors will be taken into account:

- personal and professional integrity, ethics and values;
- experience in corporate management, such as serving as an officer or former officer of a publicly held company;
- experience as a board member or executive officer of another publicly held company;
- strong finance experience;
- expertise and experience in substantive matters pertaining to our business;
- diversity of background and perspective, including with respect to age, gender, race, place of residence and specialized experience;
- experience relevant to our business industry and with relevant social policy concerns; and
- relevant academic expertise or other proficiency in an area of our business operations.

Currently, our board evaluates each individual in the context of the Board of Directors as a whole, with the objective of assembling a group that can best maximize the success of the business and represent shareholder interests through the exercise of sound judgment using its diversity of experience in these various areas.

Committees of the Board of Directors

Our Board of Directors has four standing committees, an Audit and Risk Committee, a Compensation Committee, a Corporate Governance Committee, and a Nuclear Oversight Committee, each of which will have the composition and responsibilities described below. The members of the Audit and Risk, Compensation, and the Corporate Governance Committees will satisfy the applicable independence standards of the SEC and the Nasdaq Stock Market rules. The charter of each standing committee is posted on our website, www.ConstellationEnergy.com. Our Board may also establish other committees that it deems necessary or desirable from time to time. Committee memberships may be changed subject to the discretion of our Board.

Audit and Risk Committee

Our Audit and Risk Committee consists of four members and functions pursuant to a written charter adopted by the Board of Directors. The Audit and Risk Committee's responsibilities include, among other things:

- Assists the Board of Directors in the oversight and review of the quality and integrity of the Company's financial statements and internal controls over financial reporting
- Appoints, retains and oversees the independent auditor and evaluates its qualifications, performance, independence and fees
- Oversees the Company's internal audit function
- Reviews the processes by which the Company assesses and manages enterprise risk
- Oversees compliance with the Company's Code of Business Conduct, and the process for the receipt and responses to complaints regarding accounting, internal controls, ethics or audit matters

The responsibilities of our Audit and Risk Committee are more fully described in our Audit and Risk Committee charter. Our Board of Directors has determined that each of the committee's members satisfy the applicable independence and other requirements of the Nasdaq Stock Market and the SEC for audit committees and that Ms. Brlas, Chair of the Committee, qualifies as an "audit committee financial expert" as defined under applicable SEC rules and regulations.

Compensation Committee

Our Compensation Committee consists of four members and functions pursuant to a written charter adopted by the Board of Directors. The Compensation Committee's responsibilities include, among other things:

- Assists the Board of Directors in establishing performance criteria, evaluation, and compensation for the CEO
- Approves executive compensation program design for executive officers, other than the CEO
- Monitors and reviews leadership and succession information for executive roles
- Retains the Committee's independent compensation consultant
- Reviews Compensation Discussion and Analysis and prepares the Compensation Committee Report for proxy statements

The responsibilities of our Compensation Committee, and its procedures for the consideration and determination of executive compensation, are more fully described in our Compensation Committee charter. Our Board of Directors has determined that each of the committee's members satisfies the applicable independence and other requirements of The Nasdaq Stock Market, the SEC and the IRS for compensation committee members.

Corporate Governance Committee

Our Corporate Governance Committee consists of four members and functions pursuant to a written charter adopted by the Board of Directors. The Corporate Governance Committee's responsibilities include, among other things:

- Identifies and recommends qualified candidates for election by the Board of Directors and shareholders and oversees the Board and committee structure and compensation
- Recommends Corporate Governance Guidelines and advises on corporate governance issues including evaluation processes for the Board, its committees, and directors and the CEO
- Oversees the Company's environmental strategies, including climate change and sustainability policies
- Reviews the Company's director compensation program and retains an independent compensation consultant
- Has authority to retain an independent search firm to identify candidates for a director

The responsibilities of our Corporate Governance Committee and the process for identifying and evaluating director nominees (including nominees recommended by shareholders) are more fully described in our Corporate Governance Committee charter. Our Board of Directors has determined that each of the committee's members satisfy the applicable independence and other requirements of The Nasdaq Stock Market and the SEC for Corporate Governance Committee members.

Nuclear Oversight Committee

Our Nuclear Oversight Committee consists of three members and functions pursuant to a written charter adopted by the Board of Directors. The Nuclear Oversight Committee's responsibilities include, among other things:

- Oversees the safe and reliable operation of the Company's nuclear generating facilities with a principal focus on nuclear safety
- Oversees management and operations of the Company's nuclear generating facilities and the overall organizational effectiveness of nuclear generating station operations
- Oversees compliance with policies and procedures to manage and mitigate risks associated with the security and integrity of the Company's nuclear generation assets
- Reviews environmental, health and safety issues relating to nuclear generating facilities

The responsibilities of our Nuclear Oversight Committee are more fully described in our Nuclear Oversight Committee charter.

Shareholder Nominations

A shareholder who wishes to recommend a candidate (including a self-nomination) to be considered by the Corporate Governance Committee for nomination as a Director must submit the recommendation in writing to the Chair of the Corporate Governance Committee c/o the Corporate Secretary. The Corporate Governance Committee will consider all recommended candidates and self-nominees when making its recommendation to the full Board of Directors to nominate a slate of Directors for election.

In order to be considered for election, nominations must comply with the requirements of the SEC and the provisions of our bylaws. Under our bylaws, notice of the proposed nomination must be received by the Company not later than the ninetieth day, or earlier than the one hundred twentieth day, prior to the first anniversary of the date of the preceding year's annual meeting of shareholders. Although we will not hold an annual meeting of shareholders in 2022 due to the recent completion of the separation from Exelon, for purposes of determining the timeliness of nominations for our 2023 annual meeting of shareholders, the 2022 annual meeting of shareholders will be deemed to have been held on April 26, 2022. In addition, the notice must include information required under the bylaws, including: (a) information about the nominating shareholder, (b) information about the candidate that would be required to be included in a proxy statement under the rules of the SEC, (c) a representation as to whether the shareholder intends to deliver a proxy statement to the other shareholders of CEG Parent, and (d) the signed consent of the candidate to serve as a director, if elected. Under this procedure, any shareholder can nominate any number of candidates for director for election at the annual meeting, but the shareholder's nominees will not be included in our proxy statement or form of proxy for the meeting.

Code of Conduct and Ethics

In connection with the completion of the separation from Exelon, our Board of Directors, on January 31, 2022, adopted a code of conduct and ethics (the "Code of Ethics") that applies to all of our directors, officers and employees, including our principal executive officer, principal financial officer, principal accounting officer and persons performing similar functions. The Code of Ethics is available upon written request to our corporate secretary or on our website at www.ConstellationEnergy.com. If we amend or grant any waiver from a provision of our Code of Ethics that applies to our executive officers, we will publicly disclose such amendment or waiver on our website and as required by applicable law. The information contained on, or accessible from, our website is not part of this annual report by reference or otherwise.

ITEM 11. EXECUTIVE AND DIRECTOR COMPENSATION

Compensation Discussion & Analysis

As of December 31, 2021, CEG Parent and Constellation were wholly owned subsidiaries of Exelon Corporation and CEG Parent's compensation committee had not yet been formed. All decisions regarding 2021 compensation of Constellation's and its subsidiaries' named executive officers were made by the Compensation and Leadership Development Committee of the Exelon Board of Directors (referred to in this section as the "Exelon Compensation Committee") if the executive previously served as an executive officer of Exelon, or otherwise by Exelon management. Following the distribution on February 1, 2022, the executive compensation programs, policies and practices for CEG Parent's executive officers are subject to the review and approval of the Compensation Committee of CEG Parent's Board of Directors (the "Company Compensation Committee").

For purposes of this Compensation Discussion and Analysis and the following executive compensation tables, the individuals referred to as the "named executive officers" ("NEOs") are Constellation's principal executive officer, principal financial officer and the three most highly compensated executive officers of Constellation and its subsidiaries' based on 2021 compensation. The compensation discussed in this section refers to legacy Exelon compensation plans.

The individuals determined to be our NEOs based on 2021 compensation are listed below. This information reflects positions and compensation during 2021 while we were held by Exelon and does not reflect the individuals who may be identified as NEOs by us in the future.

Christopher Crane[(a)]	President and Chief Executive Officer, Exelon
Joseph Dominguez[(b)]	President and Chief Executive Officer, Constellation
Kenneth W. Cornew[(a)]	(Former) President and Chief Executive Officer, Constellation
Daniel Eggers[(c)]	Executive Vice President and Chief Financial Officer, Constellation
Bryan Wright	(Former) Senior Vice President and Chief Financial Officer, Constellation
Bryan Hanson	Executive Vice President, Chief Generation Officer, Constellation
James Mchugh	Executive Vice President, Chief Commercial Officer, Constellation
David Rhoades	Senior Vice President, President and Chief Nuclear Officer

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(a) Mr. Crane was named principal executive officer of Constellation effective October 21, 2020. Mr. Cornew served as Senior Executive Vice President and Chief Commercial Officer, Exelon; President and Chief Executive Officer, Constellation through his departure on March 31, 2021.
(b) Mr. Dominguez was named as Executive Vice President and Chief Executive Officer of Constellation effective October 1, 2021.
(c) Mr. Eggers was named as Executive Vice President and Chief Financial Officer of Constellation effective October 1, 2021.

All NEOs have compensation that is structured in part like Exelon's executive officers, based in part on overall Exelon goals as well as goals of Constellation and its subsidiaries. The Company NEOs participated in compensation programs designed to align their interests with the Company's customers and other stakeholders.

For both the CEO and NEOs, a significant portion of their compensation is tied to the achievement of short-term and long-term financial and operational goals and is paid in the form of Exelon equity with all components except for salary being "at-risk."

CEO		All NEOs	
Base Salary	10.5 %	Base Salary	20.3 %
Annual Incentive Plan (AIP)	14.2 %	Annual Incentive Plan (AIP)	17.5 %
Long-Term Incentive Plan (LTIP)	75.3 %	Long-Term Incentive Plan (LTIP)	55.0 %
Pay at Risk (AIP + LTIP)	89.5 %	Pay at Risk (AIP + LTIP)	72.5 %

Executive Compensation Program Philosophy and Objectives

The goal of the executive compensation program is to retain and reward leaders who create long-term value by delivering on objectives that support strategic business objectives. Each element of total direct compensation is based on market data, the executive's competencies and skills, scope of responsibilities, experience and performance, retention, succession planning and organizational structure of the business.

2021 Compensation Program Structure

The 2021 compensation program is summarized below. Primary compensation elements include fixed and variable components.

Pay Element	Form	Shareholder Alignment
Salary	Cash	a) Fixed income at competitive, market-based levels attracts and retains top talent.
Annual Incentive Plans ("AIP")	Cash	b) Motivates executives to achieve key annual financial and operational goals that reflect commitment to superior operations and supporting our customers and communities
Long-Term Incentive Plan ("LTIP")	Performance Shares (67% of LTIP)	c) Drives executive focus on long-term goals supporting utility growth, financial results, and capital stewardship d) Rewards relative achievement of financial goals and stock price compared to utility peers ("UTY") over three-year period e) Aligns the interests of executives with stockholders by capping payouts if absolute TSR is negative for the prior 36-month period
	Restricted Stock (33% of LTIP)	f) Balances LTI portfolio providing executive with market competitive time-based award.

2021 Base Salaries

Base salaries for 2021 were determined by the Exelon Compensation Committee for Messrs. Crane, Cornew and Hanson. The Exelon Compensation Committee also set the base salary for Messrs. Dominguez and Eggers following their promotion in October 2021. When evaluating whether to make any adjustments, the Exelon Compensation Committee considers a number of factors including the outcome of the annual merit review, results of the annual market assessment of executive compensation provided by the Exelon Compensation Committee's independent compensation consultant, the need to retain experienced executives, individual performance, scope of responsibility, leadership skills and values, current compensation, internal equity, and legacy matters.

Base salaries for the remaining Constellation and subsidiary NEOs are set by the Exelon CEO. Base salaries may be adjusted (1) as part of the annual merit review or (2) based on a promotion or significant change in job scope. The Exelon CEO considers the results of the annual market assessment in addition to the following factors when contemplating a merit review: individual performance, scope of responsibility, leadership skills and values, current compensation, internal equity, and legacy matters.

In January 2021 as part of its annual merit review, the Exelon Compensation Committee recommended Mr. Crane's base salary be increased by 1% based on the annual market assessment conducted by the independent compensation consultant, Meridian Compensation Partners, LLC. At the same time, the Exelon Compensation Committee approved a 3.6% increase in base salary for Mr. Hanson and 1% increase for Mr. McHugh. Mr. Crane approved a 1% increase in base salary for Mr. Wright. All other executives were held flat. Merit increases were effective March 1, 2021.

2021 Annual Incentive Plan (AIP) Overview and Goal Setting

AIP metrics are linked to business goals and strategic focus areas. The goal-setting process employs a multi-layer approach and analysis that incorporates a blend of objective and subjective business considerations and other analytical methods to ensure that the goals are sufficiently rigorous. Such considerations include:

Recent History - Goals generally reflect a logical progression of results from the recent past.

Relative Performance - Performance is evaluated against a relevant group of Constellation and its subsidiaries' peers.

Strategic Aspirations - Near- and intermediate-term goals follow a trend line consistent with long-term aspirations.

Shareholder Expectations - Goals are aligned with externally communicated financial guidance and shareholder expectations.

Sustainable Sharing - Earned awards reflect a balanced degree of shared benefits between shareholders and participants.

The following process was used to determine 2021 AIP awards for each NEO:

1) Set AIP Target - Expressed as percentage of base salary. Mr. Crane's annual incentive target was 145% and for the other NEOs, the annual incentive targets ranged from 50%-100%.

2) Determine Performance Factor - Based on various financial and operating metrics.

3) Determine Individual Performance Multiplier (IPM) – IPM measures individual performance and ranged from 50% to 110% (target of 100%). Wright and Rhoades were the only executives eligible for an IPM up to a maximum of 110%. There were no IPMs for the other NEOs. The IPMs were approved by Mr. Crane.

4) Apply Final Multiplier – Multiply the target award by the performance factor and then multiply the outcome by the IPM. Awards could range from 0% to 200% of target (target of 100%).

The following tables detail the 2021 threshold, target, and distinguished, i.e., maximum, performance goals, and the results achieved for the AIP. The Exelon Compensation Committee selected the performance metrics below as they align with the long-term business strategy. Actual results reflected below are assessed based on the operational and financial key performance indicators as assigned to each business unit.

CEO and Direct Reports AIP Scorecard

2021 Goals	Threshold	Target	Distinguished	2021 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS[a][b]	$ 2.58	$ 2.87	$ 3.44	**$ 2.94**	106.7 %	74.7 %
CAIDI	90	84	79	**81**	160.0 %	12.0 %
SAIFI	0.80	0.69	0.54	**0.60**	160.0 %	12.0 %
Fleetwide Capacity Factor	92.6 %	94.6 %	95.8 %	**94.7 %**	113.2 %	8.5 %
Dispatch Match	94.8 %	97.5 %	99.4 %	**72.4 %**	— %	— %
					Payout:	**107.2 %**

ComEd Senior AIP Scorecard

2021 Goals	Threshold	Target	Distinguished	2021 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS[(a)(b)]	$ 2.58	$ 2.87	$ 3.44	**$ 2.94**	106.7 %	26.7 %
ComEd Adjusted (non-GAAP) Operating Earnings ($M)[(b)]	$ 652	$ 724	$ 833	**$ 754**	128.0 %	32.0 %
Total ComEd Operating and Maintenance Expense ($M)[(b)]	$ 1,083	$ 1,031	$ 928	**$ 957**	171.6 %	34.3 %
Value Based Engagements	80.0 %	90.0 %	100.0 %	**100.0 %**	200.0 %	5.0 %
Safety Best Practices	3	4	5	**5**	200.0 %	5.0 %
SAIFI	0.80	0.54	0.50	**0.50**	200.0 %	10.0 %
CAIDI	90	77	75	**69**	200.0 %	10.0 %
Service Level	81.5	90.0	92.1	**89.2**	200.0 %	10.0 %
Customer Satisfaction Index	7.64	8.09	8.20	**8.18**	181.8 %	9.1 %
EIMA Reliability Metrics Index	50.0 %	100.0 %	200.0 %	**120.0 %**	120.0 %	6.0 %
					Payout:	**148.1 %**
					Board Limiter Application	**120.0 %**

Business Service Center AIP Scorecard

2021 Goals	Threshold	Target	Distinguished	2021 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
BSC Total Cost ($M)[(b)]	$ 1,246	$ 1,187	$ 1,068	**$ 1,111**	164.2 %	164.2 %
					Payout:	**164.2 %**
					Board Limiter Application	**120.0 %**

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Constellation Corporate AIP Scorecard

2021 Goals	Threshold	Target	Distinguished	2021 Actual Results	Unadjusted Payout as a % of Target	Board Limiter Application
Average of Nuclear, Power, and Constellation KPIs	50.0 %	100.0 %	200.0 %	**118.1 %**	118.1 %	YES
					Payout:	**100.0 %**

Commercial Senior AIP Scorecard

2021 Goals	Threshold	Target	Distinguished	2021 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS[(a)(b)]	$ 2.58	$ 2.87	$ 3.44	**$ 2.94**	106.7 %	53.3 %
Constellation Adjusted (non-GAAP) Operating Earnings ($M)[(b)]	$ 850	$ 944	$ 1,085	**$ 718**	— %	— %
Commercial Adjusted Gross Margin ($M)[(b)]	$ 5,204	$ 5,782	$ 6,650	**$ 5,567**	81.8 %	20.3 %
					Payout:	**73.6 %**

Nuclear Senior AIP Scorecard

2021 Goals	Threshold	Target	Distinguished	2021 Actual Results	Unadjusted Payout as a % of Target	Weighted Performance
Exelon Adjusted (non-GAAP) Operating EPS[(a)(b)]	$ 2.58	$ 2.87	$ 3.44	**$ 2.94**	106.7 %	53.3 %
Constellation Adjusted (non-GAAP) Operating Earnings ($M)[(b)]	$ 850	$ 944	$ 1,085	**$ 718**	— %	— %
Fleetwide Capacity Factor	92.6 %	94.6 %	95.8 %	**94.7 %**	113.2 %	28.3 %
					Payout:	**81.6 %**

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(a) Exelon's 2021 Adjusted EPS was $2.82. However, for purposes of determining the 2021 AIP payouts for Exelon executives, $2.94 was used, which includes the impact of ($0.12) attributed to equity investments.
(b) See definitions of Non-GAAP measures beginning on page 173.

Definition of Non-GAAP Measures

Exelon reports its financial results in accordance with accounting principles generally accepted in the United States (GAAP) and supplements its reporting with certain non-GAAP financial measures, including adjusted (non-GAAP) operating earnings per share, earned ROE, and FFO/Debt to enhance investors' understanding of Exelon's performance. Our method of calculating adjusted (non-GAAP) operating earnings and operating ROE may not be comparable to other companies' presentations.

Adjusted (non-GAAP) operating earnings per share exclude certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments from economic hedging activities, unrealized gains and losses from nuclear decommissioning trust fund investments, certain costs associated with plant retirements and divestitures, costs related to cost management programs, and other items as set forth in the table below reconciling adjusted (non-GAAP) operating earnings from GAAP earnings, which is the most directly comparable GAAP measure. Management uses adjusted (non-GAAP) operating earnings as one of the primary indicators to evaluate performance, allocate resources, set incentive compensation targets and plan and forecast future periods. We believe the measure enhances an investor's overall understanding of period over period financial results and provides an indication of Exelon's baseline operating performance by excluding items that are considered by management to not be directly related to the ongoing operations of the business.

The table below reconciles reported GAAP Earnings per share to adjusted (non-GAAP) operating earnings per share for 2020 (amounts may not add due to rounding).

2021 Exelon GAAP Earnings (Loss) Per Share	**$**	**1.74**
Adjustments:		
Mark-to-market impact of economic hedging activities		(0.43)
Unrealized gains related to nuclear decommissioning trust (NDT) funds		(0.14)
Asset impairments		0.41
Plant retirements and divestitures		0.88
COVID-19 Direct Costs		0.04
Separation Costs		0.09
Acquisition Related Costs		0.02
ERP System Implementation Costs		0.01
Cost Related to Suspension of Contractual Offset		0.15
Cost management program		0.01
Change in environmental liabilities		0.01
Asset retirement obligation		(0.04)
Income tax-related adjustments		0.05
Noncontrolling interests		0.02
2021 Exelon Adjusted (non-GAAP) Operating Earnings (Loss) Per Share	**$**	**2.82**

Earned ROE is calculated using adjusted (non-GAAP) operating earnings, reflecting all lines of business for the utility businesses (electric distribution, gas distribution, transmission), divided by average shareholder's equity over the year. Management uses operating ROE as a measurement of the actual performance of the company's utility business.

FFO/Debt is a coverage ratio that compares funds from operations to total debt and is a key ratio analyzed by the credit rating agencies in determining Exelon's credit rating. An investment grade rating is critical as it increases the ability to participate in commercial business opportunities, lowers collateral requirements, creates reliable and cost-efficient access to capital markets and increases business and financial flexibility. The ratio is calculated following S&P's current methodology. The most directly comparable GAAP measure to FFO is GAAP Cash Flow from Operations and the most directly comparable GAAP measure to Debt is Long-Term Debt plus Short-Term Borrowings. Management uses FFO/Debt to evaluate financial risk by measuring the company's ability to service debt using cash from operations. We believe the measure enhances an investor's overall understanding of the creditworthiness of Exelon's operating companies.

ComEd adjusted (non-GAAP) operating earnings excludes certain costs, expenses, gains and losses and other specified items as determined appropriate by Exelon management when evaluating the performance metrics.

Constellation adjusted (non-GAAP) operating earnings excludes certain costs, expenses, gains and losses and other specified items, including mark-to-market adjustments, rate relief payments, and other items as determined appropriate by Exelon management when evaluating the performance metrics.

Commercial Adjusted Gross Margin is the total operating revenues less purchased power and fuel for the Commercial wholesale business and, for the Commercial retail services businesses, includes direct costs, and is net of any non-operating adjustments to either operating revenue or purchased power and fuel.

Utility adjusted (non-GAAP) operating earnings is the aggregate utility adjusted (non-GAAP) operating earnings, including Exelon HoldCo adjusted (non-GAAP) operating earnings.

Total ComEd Operating and Maintenance Expense excludes certain costs, expenses and other specified items as determined appropriate by Exelon management when evaluating the performance metrics.

BSC Total Costs represents Exelon Business Service Company costs, excluding certain costs, expenses and other specified items as determined appropriate by Exelon management when evaluating the performance metrics.

Due to the forward-looking nature of some forecasted non-GAAP measures, information to reconcile the forecasted adjusted (non-GAAP) measures to the most directly comparable GAAP measure may not be currently available; therefore, management is unable to reconcile these measures.

The following table shows how the formula was applied and the actual amounts awarded. The Exelon Compensation Committee applied negative discretion to limit the ComEd Senior and Business Service Center scorecards to 120% of target and the Constellation Corporate scorecard to target.

NEO	AIP Target	AIP Target	Formulaic Performance Factor[a]	Individual Performance Multiplier (IPM)	Actual Award
Crane	155.0 %	$ 2,024,192	107.2 %	100.0 %	$ 2,169,124
Dominguez	135.0 %	985,530	Blend[(a)(b)]	100.0 %	846,880
Wright	50.0 %	228,769	100.0 %	105.0 %	240,208
Eggers	90.0 %	463,450	Blend[(b)(c)]	100.0 %	478,698
Cornew	100.0 %	234,626	107.2 %	100.0 %	251,425
Hanson	85.0 %	616,250	107.2 %	100.0 %	660,374
McHugh	80.0 %	530,856	Blend[(d)]	100.0 %	422,298
Rhoades	80.0 %	547,750	81.6 %	110.0 %	491,841

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(a) Mr. Dominguez actual award is prorated based on both the ComEd Senior and CEO and Directs scorecard performance based on time in each plan.
(b) The AIP targets disclosed above reflect the target as of December 31, 2021. Mr. Dominguez and Mr. Eggers awards are also based on a blend of targets and salaries based on time in each role.
(c) Mr. Eggers actual award was prorated based on both the Business Service Center and CEO and Directs scorecard performance based on time in each plan.
(d) Mr. McHugh actual award was prorated base on both the Commercial Senior and CEO and Directs scorecard performance based on time in each plan.

Long-Term Incentive Plan (LTIP) Overview & Goal Setting Process

The Exelon Compensation Committee grants long-term equity incentive awards annually at its January or February meeting. When the total target equity incentive award is determined, the value is split between RSUs (33%) and performance shares (67%).

Restricted Stock Units ("RSUs"). RSUs granted to NEOs vest ratably over a three-year period. RSUs receive dividend equivalents that are reinvested as additional RSUs and remain subject to the same vesting conditions as the underlying RSUs. RSUs are not subject to any performance metrics.

Performance Shares. Performance shares granted to NEOs in January 2021 were converted according to the methodology outlined in the Employee Matters Agreement. Awards will be earned based on performance achieved for the scorecard approved by the Constellation Committee covering the two-year period ending on December 31, 2023. The performance metrics underlying the 2019-2021 and 2020-2022 performance share awards are listed below.

Performance share metrics	Why it is Important
Utility Earned ROE[a] (33.3%) Average utility ROE weighted by year-end rate base. Earned ROE is calculated using adjusted (non-GAAP) operating earnings, reflecting all lines of business for the utility businesses (electric distribution, gas distribution, transmission), divided by average shareholder's equity over the year.	Measure of value created by utility businesses. Aligned with our strategy to invest in our utilities where we can earn an appropriate return.
Utility Net Income[a] (33.3%) Aggregate utility adjusted (non-GAAP) operating earnings, including Exelon hold-co net operating income (loss)	Measures financial performance of the Utilities. Aligned with our strategy to grow our regulated utility business.
Exelon FFO/Debt[a] (33.4%) Funds from operations to total debt ratio. The ratio is calculated following S&P's current methodology. Management uses FFO/Debt to evaluate financial risk by measuring ability to service debt using cash from operations	Key ratio for determining our credit rating and thereby our access to capital. Aligned with our strategy to generate free cash and reduce debt.

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(a) See definitions of Non-GAAP measures beginning on page 173.

Setting Performance Share Targets. Performance share targets are set based on external commitments and analysis of sensitivities. The target for the Exelon FFO/Debt metric is aligned with the expectations of credit rating agencies.

Actual Targets Disclosed After Each Cycle. Actual targets used in our performance share cycles are not disclosed until each cycle is completed to safeguard the confidentiality of our long-term outlook on projected performance. This policy supports the propriety of our long-standing disclosure practices to only issue annual performance guidance as part of our financial disclosure policies.

Performance Share Awards Subject to TSR Modifier and Cap. Performance share awards are subject to a total shareholder return ("TSR") modifier that compares Exelon's performance relative to the performance of the UTY total return index on a point by point basis. Performance share awards are also subject to a TSR cap that will limit payouts at target if TSR is negative for the prior 36-month period.

The Exelon Compensation Committee used the following process to determine performance share targets and awards:

1) *Establish Performance Share Award Target* - Targets are set in January/February of the first year of the performance cycle.

2) *Determine Performance Multiplier* - The Performance Multiplier is based on performance achieved over the three-year cycle. Performance can range from 0% to 150% of target (target of 100%).

3) *Determine TSR Modifier* - Calculated by subtracting the TSR of the UTY over the three-year performance period from Exelon's TSR for the same three-year period.

4) *Calculate Final Multiplier* - Calculated by multiplying the Performance Multiplier by (100% + TSR Modifier). This value is the Final Multiplier.

5) *Apply Final Multiplier & TSR Cap (if applicable)* - Apply the Final Multiplier to determine the number of shares issued. If Exelon's absolute TSR for the final 12-month of the performance period is negative, payout will be capped at 100%. Awards can range from 0% to 200% of target (target of 100%) after application of the TSR modifier.

2019 – 2021 Performance and Performance Share Payout Determinations

The following table details the 2019 - 2021 threshold, target, and distinguished performance goals, and the results achieved. The performance multiplier for the 2019 - 2021 Performance Share awards was calculated to be **80.5%** of target, based on the following:

Performance Share Scorecard

	Metric Weighting	Threshold (50%)	75%	Target (100%)	125%	Distinguished (150%)	Actual Score	Actual Award v. Metric Weighting
Utility Earned ROE[(a)(b)]	33.3 %	8.4%		9.3%		10.0%	**9.2%**	31.4 %
Utility Net Income ($M)[(a)(b)]	33.3 %	$ 1,819		$ 2,053		$ 2,213	**$ 2,040**	32.4 %
Exelon FFO/Debt[(a)(b)]	33.4 %	≥16.0% and <17.0%	≥17.0% and <18.0%	≥18.0% and <22.0%	≥22.0% and <24.0%	≥24.0%	**16.5 %**	16.7 %
							Committee Approved Performance:	**80.5 %**

(a) See definitions of Non-GAAP measures beginning on page 173.
(b) The Utility Earned ROE and Utility Net Income use interpolation between threshold, target, and distinguished levels of performance whereas the FFO/Debt metric uses a "stair-step" approach with no interpolation between the performance levels.

Payout Determinations. The Exelon Compensation Committee approved a payout of 70.6%, based on 2019 - 2021 performance and the application of a TSR modifier of (12.3)% based on 2019 - 2021 TSR performance relative to the UTY total return.

The following table shows how the formula was applied and the actual amounts awarded.

NEO	Target Shares		Performance Factor		Actual Award
Crane	155,683	x	70.6 %	=	**109,928**
Dominguez	15,993	x	70.6 %	=	**11,293**
Wright	6,907	x	70.6 %	=	**4,877**
Eggers	6,907	x	70.6 %	=	**4,877**
Cornew	41,310	x	70.6 %	=	**29,169**
Hanson	20,522	x	70.6 %	=	**14,491**
McHugh	23,707	x	70.6 %	=	**16,740**
Rhoades	14,861	x	70.6 %	=	**10,493**

Performance Awards Settled in Common Stock and/or Cash. Pursuant to the terms of the long-term incentive program, all NEOs that have achieved 200% or more of their stock ownership targets receive performance share award payouts in cash. Due to the timing of the separation, the Exelon Compensation Committee approved 100% cash settlement for all participants.

2021 Target Compensation for Named Executive Officers

The table below lists the target value of the compensation elements for each NEO as of December 31, 2021.

	Cash Compensation			Long-Term Incentives			
NEO	Base	AIP Target	Target Total Cash	RSUs (33% of LTIP)	Performance Shares (67% of LTIP)	Target Total LTIP	Target Total Direct Compensation
Crane	$ 1,305,930	155.0 %	$ 3,330,122	$ 3,630,000	$ 7,370,000	$ 11,000,000	$ 14,330,122
Dominguez	1,050,000	135.0 %	2,467,500	2,485,725	5,046,775	7,532,500	10,000,000
Wright	457,538	50.0 %	686,307	161,040	326,960	488,000	1,174,307
Eggers	650,000	90.0 %	1,235,000	582,450	1,182,550	1,765,000	3,000,000
Cornew	—	— %	—	—	—	—	—
Hanson	725,000	85.0 %	1,341,250	726,000	1,474,000	2,200,000	3,541,250
McHugh	663,570	80.0 %	1,194,426	552,750	1,122,250	1,675,000	2,869,426
Rhoades	700,000	80.0 %	1,260,000	607,200	1,232,800	1,840,000	3,100,000

Shareholder Engagement

The Exelon Compensation Committee regularly reviews executive compensation, taking into consideration input received through regular and ongoing engagement with investors. Feedback is typically solicited throughout the year in connection with the annual meeting of shareholders and the Exelon Compensation Committee's review of the executive compensation program. The Chairs of Exelon's Compensation and Corporate Governance Committees participated in select investor discussions in 2021. Feedback from all discussions was shared with the appropriate board committee and/or the full board. Shareholders in general expressed their approval of the ongoing executive compensation program and did not request any significant changes during our engagement conversations.

2021 Compensation Decisions – Setting Target Total Direct Compensation ("TDC")

Setting Target TDC for Mr. Crane: The Exelon Compensation Committee is responsible for reviewing and recommending the Exelon CEO's target total direct compensation. The CEO's compensation is then approved by the independent members of the Exelon board. The Exelon Compensation Committee fulfills this responsibility by analyzing peer group compensation and performance data with its independent compensation consultant. The Committee also reviews the various elements of the CEO's compensation in the context of the target TDC, which includes base salary, annual and long-term incentive target opportunities.

Setting Target TDC for Messrs. Hanson and McHugh: The Exelon Compensation Committee is also responsible for approving the executive compensation for each of Exelon's executive officers by analyzing peer group compensation and performance data.

Setting Target TDC for the other NEOs: The Exelon CEO analyzes a variety of data to gauge market competitiveness, including peer group compensation and performance data provided by Exelon's independent compensation consultant. TDC can vary by named executive officer based on competencies and skills, scope of responsibilities, the executive's experience and performance, retention, succession planning and the organizational structure of the businesses (e.g., internal alignment and reporting relationships).

Role of the Compensation Consultant

As referenced earlier, the Exelon Compensation Committee retains Meridian Compensation Partners, LLC ("Meridian"), an independent compensation consultant, to support its duties and responsibilities. Meridian provides advice and counsel on executive and director compensation matters and provides information and advice regarding market trends, competitive compensation programs, and strategies including as described below:

- Market data for each senior executive position, including evaluating Exelon's compensation strategy and reviewing and confirming the peer group used to prepare the market data,
- An independent assessment of management recommendations for changes in the compensation structure,

- Assisting management to ensure Constellation and its subsidiaries' executive compensation programs are designed and administered consistent with the Exelon Compensation Committee's requirements, and
- Ad hoc support on executive compensation matters and related governance trends.

Peer Groups Used for Benchmarking 2021 Executive Compensation

Exelon uses a blended peer group for assessing our executive compensation program that consists of two sub-groups: energy services peers and general industry peers because (1) there are not enough energy services peers with size, scale and complexity comparable to Exelon to create a robust energy services-only peer group, and (2) Exelon's market for attracting talent includes general industry peers, with key executives hired from several Fortune 100 companies. When selecting general industry peers, we look for capital asset-intensive companies with size, scale and complexity similar to Exelon, and we also consider the extent to which they may be subject to the effects of volatile commodity prices similar to Exelon's sensitivity to commodity price volatility. Exelon evaluates its peer group on an annual basis in July and adjusts for changes with our energy and general industry peers when needed.

Exelon's revenues are at the 64th percentile of the following blended peer group comprising 21 companies:

1) Energy Services (11 peer companies): American Electric Power Company, Inc.; Dominion Energy, Inc.; DTE Energy; Duke Energy Corporation; Edison International; Entergy Corporation; FirstEnergy Corporation; NextEra Energy, Inc.; Public Service Enterprise Group, Inc.; Sempra Energy; and The Southern Company.

2) General Industry (10 peer companies): 3M Company; Deere & Company; Delta Air Lines; General Dynamics Corporation; Honeywell International, Inc.; International Paper Company; Lockheed Martin; Marathon Petroleum Company; Northrop Grumman Corporation; and Valero Energy Corporation.

Because there is a correlation between the size of an organization and its compensation levels, market data is statistically adjusted using a regression analysis. This commonly applied technique allows for a more precise estimate of the market value of Constellation and its subsidiaries given the size and scope of responsibility for Constellation and its subsidiaries' executive roles. Each element of NEO compensation is then compared to these size-adjusted medians of the peer group.

In preparation for the separation, a blended peer group consisting of a broad representation of energy and materials companies was used for benchmarking the assessment of 2022 compensation for named executive officers of the Company. Constellation will also evaluate its peer group on an annual basis in July and adjusts for changes with our energy and general industry peers when needed.

Constellation's revenues are at the 64th percentile of the following blended peer group comprising 15 companies:

1) Energy Services and Independent Power Producers ("IPPs") (9 peer companies): American Electric Power Company, Inc.; Dominion Energy, Inc.; Duke Energy Corporation; Entergy Corporation; NextEra Energy, Inc.; NRG Energy, Inc.; The AES Corporation; Vistra Corp; and The Southern Company.

2) General Industry (6 peer companies): DuPont de Nemours, Inc.; International Paper Company; Kinder Morgan, Inc.; Nucor Corporation; Occidental Petroleum Corporation; and WestRock Company.

Looking Forward to 2022

Annual Incentive Plan

Based on overall company strategy, the 2022 plan design will be based 70% on a financial metric and 30% on operational metrics.

The plan design metric weightings include:

- 70% weighting on Adjusted EBITDA,
- 10% weighting on Fleetwide Capacity Factor as assessment of Nuclear operational performance,

- 10% weighting on Dispatch Match as assessment of Power operational performance, and
- 10% on Customer Satisfaction (which considers both Net Promoter Score, which measures C&I business customer loyalty, and Customer Satisfaction, which measures residential satisfaction from recent support experience).

Long-term Incentive Plan

The long-term incentive plan is aligned with the Constellation business strategy, the 2021 and 2022 PShare programs will be based on a 100% Free Cash Flow before Growth metric with a CFO/Debt negative modifier.

Stock Ownership

To strengthen the alignment of executive interests with those of Exelon's shareholders, officers of Constellation and its subsidiaries are required to own certain amounts of Exelon common stock five years following his or her employment or promotion to a new position (six-times base salary for Mr. Crane; two to three times base salary for the other NEOs). As of the annual measurement date of June 30, 2021, all NEOs had met their stock ownership guidelines. We expect to adopt a similar stock ownership policy for officers of the Company.

Prohibition on Hedging and Pledging of Common Stock; Other Trading Requirements

Exelon requires executive vice presidents and above who wish to sell Exelon common stock to do so only through the adoption of a stock trading plan meeting the requirements of SEC Rule 10b5-1(c). This requirement is designed to enable officers with the ability to diversify holdings in an orderly manner to meet personal financial plans. Our insider trading policy includes provisions that prohibit directors and employees (including officers) and certain of their related persons (including certain family members and entities which they own a significant interest) from engaging in short sales, put or call options, hedging transactions, pledging, or other derivative transactions involving Exelon stock. We expect to adopt a similar policy for officers of the Company.

Clawback Policy

The policy provides broad discretionary ability to clawback incentive compensation when deemed appropriate. Under the policy, the Exelon board has sole discretion to recoup incentive compensation if it determines that (a) the incentive compensation was based on the achievement of financial or other results that were subsequently restated or corrected, (b) the incentive plan participant engaged in fraud or intentional misconduct that caused or contributed to the need for restatement or correction, (c) a lower incentive plan award would have been made to the participant based on the restated or corrected results, and (d) recoupment is not precluded by applicable law or employment agreements.

The Exelon board or Exelon Compensation Committee may also seek to recoup incentive compensation paid or payable to current or former incentive plan participants if, in its sole discretion, the Exelon board or Exelon Compensation Committee determines that (a) the current or former incentive plan participant breached a restrictive covenant or engaged or participated in misconduct or intentional or reckless acts or omissions or serious neglect of responsibilities that caused or contributed to a significant financial loss or serious reputational harm to Exelon or its subsidiaries regardless of whether a financial statement restatement or correction of incentive plan results was required, and (b) recoupment is not precluded by applicable law or employment agreements.

We have adopted clawback policies that are similar to those maintained by Exelon.

Risk Management Assessment of Compensation Policies and Practices

The Exelon Compensation Committee reviews Exelon's compensation policies and practices as they relate to the risk management practices and risk-taking incentives. The Exelon Compensation Committee partners with Constellation's enterprise risk management group to assess and validate that the controls in place continued to mitigate incentive compensation risks.

Tax Consequences

Under Section 162(m) of the Internal Revenue Code (the Code), generally NEO compensation over $1 million for any year is not deductible for United States income tax purposes. The Compensation and Leadership Development Committee believes that it must maintain flexibility in its approach to executive compensation in order to structure a program that it considers to be the most effective in attracting, motivating and retaining the Company's key executives, and therefore, the deductibility of compensation is one of several factors considered when making executive compensation decisions.

Compensation Committee Report

The Compensation committee has reviewed and discussed with management the Compensation Discussion and Analysis and, based on such review and discussion, the Committee recommended the Board approve the Compensation Discussion and Analysis be included in this Report.

The Compensation Committee

Name
Yves C. de Balmann, Chair
Bradley Halverson
Julie Holzrichter
Ashish Khandpur

Executive Compensation Tables

2021 Summary Compensation Table

Name	Year	Salary	Bonus[(a)]	Stock Awards[(b)]	Non-Equity Incentive Plan Compensation[(c)]	Change in Pension Value and Nonqualified Deferred Compensation Earnings[(d)]	All Other Compensation[(e)]	Total
Christopher Crane								
President and Chief Executive Officer, Exelon	2021	$ 1,303,595	$ —	$ 11,000,019	$ 2,169,124	$ 1,071,663	$ 212,977	$ 15,757,378
	2020	1,293,000	—	11,000,013	1,897,536	757,754	214,500	15,162,803
Joseph Dominguez								
President and Chief Executive Officer, Constellation	2021	752,504	—	1,130,048	846,880	181,413	441,432	3,352,277
Kenneth Cornew								
(Former) President and Chief Executive Officer, Constellation	2021	404,100	—	1,955,605	251,425	176,751	3,900,007	6,687,888
	2020	947,189	—	2,918,828	963,055	299,794	338,335	5,467,201
Bryan Wright								
(Former) Senior Vice President and Chief Financial Officer, Constellation	2021	456,720	11,438	488,034	228,769	149,770	25,315	1,360,046
	2020	450,936	64,723	488,016	294,455	123,461	25,975	1,447,566
Daniel Eggers								
Executive Vice President and Chief Financial Officer, Constellation	2021	561,051	—	550,024	478,698	82,699	48,901	1,721,373
Bryan Hanson								
Executive Vice President, Chief Generation Officer, Constellation	2021	720,486	—	2,220,056	660,374	560,922	74,320	4,216,158
	2020	686,418	—	1,450,054	594,728	885,522	59,602	3,676,324
James McHugh								
Executive Vice President, Chief Commercial Officer, Constellation	2021	662,384	—	2,564,644	422,298	27,257	45,655	3,722,238
	2020	653,981	29,121	1,675,059	582,417	26,209	60,738	3,027,525
David Rhoades								
Senior Vice President, President and Chief Nuclear Officer	2021	684,254	44,713	1,500,040	447,128	652,587	29,780	3,358,502

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(a) In recognition of their overall performance, certain NEOs received an individual performance multiplier (IPM) to their annual incentive payments or other special recognition awards. Messrs. Crane, Cornew, Hanson and McHugh were not eligible for an IPM.

(b) The amounts shown in this column include the aggregate grant date fair value of restricted stock unit and performance share unit awards for the 2021-2023 performance period granted January 25, 2021 and October 29, 2021. The grant date fair values of the stock awards have been computed in accordance with FASB ASC Topic 718. Note, Mr. Cornew's award was reduced at the separation date to reflect a prorated award based on time in role during 2021. The 2020-2022 performance share award component of the stock award values depicted above are subject to performance conditions and the grant date fair value assumes the achievement of the target level of performance; however, values may be higher based on performance including the maximum total shareholder return multiplier as follows:

Name	Performance Share Award Value	
	At Target	At Maximum
Crane	$ 7,370,020	$ 14,740,040
Dominguez	757,108	1,514,216
Cornew	1,955,605	3,911,210
Wright	326,989	653,978
Eggers	368,518	737,036
Hanson	1,474,030	2,948,060
McHugh	1,122,288	2,244,576
Rhoades	1,005,026	2,010,052

(c) The amounts shown in this column for 2021 represent payments made pursuant to the Annual Incentive Plan.
(d) The amounts shown in this column represent the change in the accumulated pension benefit for the NEOs from December 31, 2020 to December 31, 2021. None of the NEOs had above market earnings in a non-qualified deferred compensation account in 2021.
(e) All Other Compensation: The following table describes the incremental cost of other benefits provided in 2021 that are shown in this column.

All Other Compensation

Name	Perquisites[a]	Reimbursement for Income Taxes[b]	Exelon Contributions to Savings Plans[c]	Exelon Paid Term Life Insurance Premiums[d]	Other[e]	Total
Crane	$ 128,034	$ —	$ 39,113	$ 45,830	$ —	$ 212,977
Dominguez	252,031	162,636	22,230	4,535	—	441,432
Cornew	26,301	56,653	7,137	3,752	3,806,164	3,900,007
Wright	12,290	—	8,700	4,325	—	25,315
Eggers	28,683	—	16,709	3,509	—	48,901
Hanson	42,651	6,536	21,019	4,114	—	74,320
McHugh	22,101	—	19,178	4,376	—	45,655
Rhoades	16,840	—	8,700	4,240	—	29,780

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(a) Amounts reported for personal benefits provided to NEOs include: (1) transportation related benefits (including corporate aircraft, parking, spousal and family travel); and (2) other benefits (including personal financial planning, company gifts, and matching charitable contributions).
   i. Amounts reported for the personal use of corporate aircraft are based on the aggregate incremental cost to Exelon and are calculated using the hourly incremental cost for flight services, including federal excise taxes, fuel charges, and domestic segment fees. Exelon's board-approved policy on corporate aircraft usage includes spousal/domestic partner and other family member usage when appropriate. Amounts reported in this column for Mr. Crane, Mr. Dominguez and Mr. Eggers include $83,376, $17,528, $11,843 respectively for personal use of corporate aircraft. Amounts include $14,183 for spousal travel for Mr. Hanson.
   ii. Amounts include the value received by Mr. Dominguez for his relocation from Illinois to Pennsylvania as Chief Executive Officer of Constellation. The value of the benefit included is $217,663 which includes closing, storage, and inspection costs. Benefits were provided for under the relocation program's standard terms.
   iii. Limited personal financial planning benefits valued at $16,840 for each executive are provided with usage values imputed as additional taxable income. Executive officers may request matching gifts to qualified charitable organizations in amounts up to $10,000 and up to $15,000 for Mr. Cornew under the Constellation Energy Group, Inc. legacy policy.
(b) Exelon provides reimbursements of tax obligations incurred when: employees are required to work outside their state of home residence and encounter double taxation in states and localities where tax credits are not permitted in home state tax filings; business-related spousal travel involves personal benefits and income is imputed to the employee and for required relocation and housing/living expenses incurred in compliance with regulatory requirements.
(c) The amounts represent the respective corporate matching contributions to the NEOs' accounts. Each of the NEOs participated in the 401(k) Plan and the Deferred Compensation Plan. Mr. Wright and Mr. Rhoades do not participate in the Deferred Compensation Plan.
(d) Exelon provides basic term life insurance, accidental death and disability insurance, and long-term disability insurance to all employees, including NEOs. The values shown in this column include the premiums paid during 2021 for additional term life insurance policies for the NEOs and for additional supplemental accidental death and dismemberment insurance and long-term disability over and above the basic coverage provided to all employees.

(e) For Mr. Cornew, the aggregate amount includes severance payments of $3,806,164 distributed pursuant to the terms of the Senior Management Severance Plan, representing two times the sum of Mr. Cornew's then current base salary and target annual incentive for the year of termination.

2021 Grants of Plan-Based Awards

		Estimated Possible Payouts Under Non-Equity incentive Plan Awards[(a)]			Estimated Possible Payouts Under Equity Incentive Plan Awards[(b)]				
Name	Grant Date	Threshold	Plan	Maximum	Threshold	Target	Maximum	All other Stock Awards: Number of Shares or Units[(c)]	Grant Date Fair Value of Stock and Option Awards[(d)]
Crane	1/25/2021	$ 75,907	$ 2,024,192	$ 4,048,383					
	1/25/2021				28,341	170,012	340,024		$ 7,370,020
	1/25/2021							83,737	3,629,999
Dominguez	10/1/2021	53,156	1,417,500	2,835,000					
	1/25/2021				2,911	17,465	34,930		757,108
	1/25/2021							8,603	372,940
Cornew	1/25/2021	35,683	951,541	1,903,082					
	1/25/2021				7,520	45,112	90,224		1,955,605
Wright	1/25/2021	57,192	228,769	457,538					
	1/25/2021				1,257	7,543	15,086		326,989
	1/25/2021							3,715	161,045
Eggers	10/1/2021	21,938	585,000	1,170,000					
	1/25/2021				1,417	8,501	17,002		368,518
	1/25/2021							4,187	181,506
Hanson	1/25/2021	23,109	616,250	1,232,500					
	1/25/2021				5,668	34,003	68,006		1,474,030
	1/25/2021							16,748	726,026
McHugh	1/25/2021	19,907	530,856	1,061,712					
	1/25/2021				4,316	25,889	51,778		1,122,288
	1/25/2021							12,751	552,756
	4/5/2021							20,000	889,600
Rhoades	1/25/2021	70,000	560,000	1,120,000					
	1/25/2021				3,865	23,184	46,368		1,005,026
	1/25/2021							11,419	495,014

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(a) All NEOs have annual incentive plan target opportunities based on a fixed percentage of base salaries. Under the terms of the AIP, threshold performance earns 50% of the respective target, while performance at plan earns 100% of the respective target and the maximum payout is capped at 200% of target.
   i. For Messrs. Crane, Dominguez, Cornew, Eggers, and Hanson and Mr. McHugh, the possible payout at threshold for AIP was calculated at 3.8% of target based on a threshold payout of 50% for the lowest weighted metric of 7.5%.
   ii. For Mr. Wright, the possible payout at threshold for AIP was calculated at 25% of target based on a threshold payout of 50% and an individual performance multiplier of 50%.
   iii. For Mr. Rhoades, the possible payout at threshold for AIP was calculated at 12.5% of target based on threshold payout of 50% for the lowest weighted metric and an individual performance multiplier of 25%.
      1. For additional information about the terms of these programs, see "Compensation Discussion and Analysis" above.

(b) NEOs have a long-term performance share unit target opportunity that is a fixed number of performance share units commensurate with the officer's position. The possible payout at threshold for performance share unit awards was calculated at 16.7% of target. The possible maximum payout for performance share units was calculated at 150% of target, with an uncapped total shareholder return multiplier, capped at 200% of target. For additional information about the terms of these programs, see Compensation Discussion and Analysis and the footnotes to the Summary Compensation Table above.

(c) This column shows restricted stock unit awards made during the year. The vesting dates of the awards are provided in tickmark (b) to the Outstanding Equity Table below.

(d) This column shows the grant date fair value, calculated in accordance with FASB ASC Topic 718, of the performance share unit awards and restricted stock units granted to each NEO during 2020. Fair value of performance share unit awards granted on January 27, 2020 are based on an estimated payout of 100% of target.

2021 Outstanding Equity Awards at Year End

	Option Awards[a]				Stock Awards			
Name	Number of Securities Underlying Unexercised Options That Are Exercisable	Number of Securities Underlying Unexercised Options That Are Not Exercisable	Option Exercise or Base Price	Option Expiration Date	Number of Shares or Units of Stock That Have Not Yet Vested[b]	Market Value of Shares or Units of Stock That Have Not Yet Vested Based on 12/31 Closing Price $57.76[b]	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Yet Vested[c]	Equity Incentive Plan Awards: Market or Payout Value or Unearned Shares, Units or Other Rights That Have Not Yet Vested[c]
Crane	—	—	$ —	—	279,511	$ 16,144,555	651,850	$ 37,650,856
Dominguez	—	—	—	—	68,717	3,969,094	66,964	3,867,841
Wright	—	—	—	—	12,403	716,397	28,920	1,670,419
Eggers	—	—	—	—	33,076	1,910,470	31,886	1,841,735
Cornew	—	—	—	—	29,169	1,684,801	104,990	6,064,222
Hanson	—	—	—	—	82,742	4,779,178	109,112	6,302,309
McHugh	—	—	—	—	63,028	3,640,497	99,262	5,733,373
Rhoades	—	—	—	—	72,643	4,195,860	86,332	4,986,536

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(a) Non-qualified stock options were previously granted to NEOs pursuant to the Company's long-term incentive plans. All grants are fully vested and expire on the tenth anniversary of the grant date.

(b) The amount shown includes unvested restricted stock unit awards and the performance share award earned for the performance period beginning January 1, 2019 and ending December 31, 2021, which vested on January 28, 2022. The unvested restricted stock unit awards are composed of the final third of the award made in January 2019, which vested on January 6, 2022; two-thirds of the award made in January 2020, half of which vested on January 6, 2022 and half of which will vest on the date of the Constellation Compensation Committee's first regular meeting in 2023; and the full award granted on January 25, 2021, one-third of which vested on January 6, 2021 and one-third of which will vest on the date of each of the Constellation's Compensation Committee's first regular meetings in 2023 and 2024, respectively. All RSU awards accrue additional shares through automatic dividend reinvestment. For Mr. Dominguez, Eggers, Hanson, and Rhoades the amount shown includes grants of 10,000, 20,000, 40,000 and 40,000 restricted stock units awarded on January 29, 2018, which vest on January 6, 2022. For Mr. Dominguez, the amount also includes a 30,000 grant awarded on August 1, 2018, which will vest on August 1, 2022. For Mr. McHugh, the amount includes 20,000 restricted stock units awarded on April 5, 2021, which will vest on April 5, 2025. All shares are valued at $57.76, the closing price on December 31, 2021.

(c) The amount shown includes the target performance share awards granted on January 27, 2020 for the performance period ending December 31, 2022 and the target performance share awards granted on January 25, 2021 for the performance period ending December 31, 2023. These target awards have been increased to reflect the highest level of performance for the period, 200%. All shares are valued at $57.76, the closing price on December 31, 2021.

2021 Option Exercises and Stock Vested

	Option Awards		Stock Awards[a]	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting	Value Realized on Vesting
Crane	285,000	$ 4,068,888	198,406	$ 8,600,892
Dominguez	16,000	233,214	21,709	941,104
Wright	—	—	9,374	406,365
Eggers	—	—	8,918	386,578
Cornew	70,000	393,280	56,065	2,430,438
Hanson	—	—	27,854	1,207,488
McHugh	—	—	32,635	1,414,729
Rhoades	—	—	20,171	874,399

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(a) Share amounts are composed of the following tranches of prior awards that vested on January 25, 2021: the performance share awards granted for the performance period of January 1, 2018 through December 31, 2020; the final third of the

RSU awards granted in January 2018, the second third of the RSU awards granted in February 2019 and the first third of the RSU awards granted in January 2020. All of these awards were valued at $43.35 upon vesting.

Pension Benefits

The plans below were sponsored by Exelon Corporation as of December 31, 2021, and that as of February 1, 2022 Constellation established mirror pension plans to maintain the same benefits described below for NEOs.

Exelon sponsors the Exelon Corporation Retirement Program, a defined benefit pension plan that includes the Service Annuity System (SAS), a traditional pension plan covering NEOs who commenced employment prior to January 1, 2001 and the Cash Balance Pension Plan ("CBPP"), an account-based plan covering eligible NEOs hired between January 1, 2001, and February 1, 2018, and certain NEOs who previously elected to transfer to the CBPP from the SAS. Exelon also sponsors the Pension Plan of Constellation Energy Group, Inc. ("CEG Pension Plan"), which covers certain legacy Constellation Energy Group, Inc. employees. It includes a traditional pension formula for employees hired before January 1, 2000, and a pension equity formula ("PEP") for employees hired thereafter or who elected to participate in that formula. The Retirement Program and CEG Pension Plan are intended to be tax-qualified under Section 401(a) of the Internal Revenue Code.

Service Annuity System ("SAS")

For NEOs participating in the SAS, the annuity benefit payable at normal retirement age is equal to the sum of 1.3% of the participant's earnings as of December 25, 1994, reduced by a portion of the participant's Social Security benefit as of that date, plus 1.6% of the participant's highest average annual pay, multiplied by the participant's years of credited service (up to a maximum of 40 years). Pension-eligible compensation for the SAS's Final Average Pay Formula includes base pay and annual incentive awards. Benefits under the SAS are vested after five years of service.

The "normal retirement age" under the SAS is 65. The plan also offers an early retirement benefit prior to age 65, which is payable if a participant retires after attainment of age 50 and completion of 10 years of service. The annual pension payable under the plan is determined as of the early retirement date, reduced by 2% for each year of payment before age 60 to age 58, then 3% for each year before age 58 to age 50. In addition, under the SAS, the early retirement benefit is supplemented prior to age 65 by a temporary payment equal to 80% of the participant's estimated monthly Social Security benefit. The supplemental benefit is partially offset by a reduction in the regular annuity benefit.

Cash Balance Pension Plan ("CBPP")

For NEOs who participate in the CBPP, a notional account is established for each participant, and the account balance grows as a result of annual benefit credits and annual investment credits. NEOs who transferred from the SAS to the CBPP also have a frozen transferred SAS benefit and received a "transition" credit based on age, service and compensation at the time of transfer. When the CBPP was initially established in 2001, it provided an annual benefit credit of 5.8% of an employee's base pay and annual incentive award for the year, and an annual investment credit based on the average of that year's S&P 500 stock index return and the 30-year Treasury rate for the month of November (subject to 4% minimum). The benefit credit percentages and investment credit rates have been subsequently modified periodically pursuant to U.S. Treasury Department guidance on cash balance plans. NEO participants in the CBPP currently receive an annual benefit credit ranging from 7.0% to 10.5% (depending on length of service) of base salary and annual incentive award, and an annual investment credit based on the third segment spot rate of interest on long-term investment grade corporate bonds for the month of November of the year credited (subject to a 4% minimum). Benefits vest after three years of service and are payable in an annuity or a lump sum at any time following termination of employment. Apart from the benefit credits and the vesting requirement, years of service are not relevant to a determination of accrued benefits under the CBPP.

In 2019, Exelon and its subsidiaries also provided a one-time Transition Benefit Credit to all CBPP participants in recognition of the transition to a fully fixed income investment credit rate. The amount of the credit ranged from 0% to 30.5% of 2018 annualized base pay, based on years of service as of December 31, 2007.

Pension Plan of Constellation Energy Group, Inc. (CEG Pension Plan)

For NEOs who participate in the PEP, a lump sum benefit amount is computed based on covered earnings multiplied by a total credit percentage. Covered earnings are equal to the average of the highest three of the last five twelve-month periods' base pay plus annual incentive awards. The total service credit percentage is equal to the sum of the credit percentages based on the following formula: 5% per year of service through age 39, 10% per year of service from age 40 to age 49, and 15% per year of service after age 49. No benefits are available under the PEP until a participant has at least three years of vesting service. Benefits payable under the PEP are paid as an annuity unless a participant elects a lump sum within 60 days after separation.

Supplemental Management Retirement Plan ("SMRP") and Constellation Energy Group, Inc. Benefits Restoration Plan ("CEG BRP")

All NEOs participate in either the SMRP or the CEG BRP. The SMRP and CEG BRP provides supplemental benefits to the benefits provided under the tax-qualified Retirement Program and CEG Pension Plan, respectively, for individuals whose annual compensation exceeds the limits imposed under the Internal Revenue Code. Under the terms of the SMRP and the CEG BRP, participants are provided the amount of benefits they would have received under the SAS, CBPP or PEP but for the application of the Internal Revenue Code limits.

Up to two years of service credits may be provided under the SMRP and the CEG BRP upon a qualifying termination of employment under severance or change in control agreements or awards that are intended to make up for lost pension benefits from another employer.

The amount of the change in the pension value for each of the NEOs is the amount included in the Summary Compensation Table above. The present value of each NEO's accumulated pension benefit is shown in the following tables. The present value for CBPP participants is the account balance.

2021 Pension Benefits

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
Crane	SAS	23.26	$ 1,679,097	$ —
	SMRP[(a)]	33.26	20,422,595	—
Dominguez	CBPP	19.35	566,202	—
	SMRP	19.35	964,583	—
Cornew	CBPP	27.59	1,028,889	891,646
	SMRP	27.59	2,404,519	2,730,689
Wright	PEP	18.33	558,125	—
	CEG BRP	18.33	991,191	—
Eggers	CBPP	5.76	115,954	—
	SMRP	5.76	224,926	—
Hanson	SAS	33.30	2,478,250	—
	SMRP	33.30	6,719,224	—
McHugh	CBPP	18.79	340,737	—
	SMRP	18.79	367,949	—
Rhoades	SAS	32.55	2,428,880	—
	SMRP	32.55	5,411,360	—

(a) Based on discount rates prescribed by the SEC proxy disclosure guidelines, Mr. Crane's non-qualified Supplemental Management Retirement Plan (SMRP) present value is $20,422,595. Based on lump sum conversion interest rates defined for immediate distributions under the non-qualified plan, the comparable lump sum amount applicable for service through December 31, 2021 is $32,455,156. Note that, in any event, payments made upon termination may be delayed by six months in accordance with U.S. Treasury Department guidance.

Deferred Compensation Programs

Exelon Corporation Deferred Compensation Plan

The Exelon Corporation Deferred Compensation Plan is a non-qualified plan that permits the NEOs to defer certain cash compensation to facilitate tax and retirement planning. The Deferred Compensation Plan also permits Constellation and its subsidiaries to credit related matching contributions that would have been contributed to the Exelon Corporation Employee Savings Plan (the Exelon's tax-qualified 401(k) plan) but for the applicable limits under the Internal Revenue Code.

Exelon Corporation Employee Savings Plan

The Employee Savings Plan is intended to be tax-qualified under Sections 401(a) and 401(k) of the Internal Revenue Code. Exelon maintains the Employee Savings Plan to attract and retain qualified employees, including the NEOs, and encourage retirement savings, which under the Plan may be supplemented by Constellation and its subsidiaries' matching contributions. Constellation and its subsidiaries maintain the excess matching feature of the Deferred Compensation Plan to enable highly compensated employees to save for retirement to the extent they otherwise would have, were it not for the limits established by the IRS.

Once participants in the Employee Savings Plan reach their statutory contribution limit during the year, their elected payroll contributions and Constellation and its subsidiaries' matching contribution will be credited to their accounts in the Deferred Compensation Plans. The investment options under the Deferred Compensation Plan consist of a basket of investment fund benchmarks substantially the same as those funds available through the Employee Savings Plan. Deferred amounts represent unfunded, unsecured obligations of Constellation and its subsidiaries.

2021 Nonqualified Deferred Compensation

Name	Executive Contributions in 2021(a)	Registrant Contributions in 2021(b)	Aggregate Earnings in 2021(c)	Aggregate Withdrawals/ Distributions	Aggregate Balance at 12/31/21(d)
Crane	$ 108,828	$ 32,648	$ 562,085	$ —	$ 3,050,967
Dominguez	22,549	13,530	8,420	—	82,658
Cornew	—	—	156,163	—	995,173
Wright	—	—	—	—	—
Eggers	13,698	8,219	27,671	—	111,790
Hanson	36,250	13,594	20,649	—	266,604
McHugh	17,972	63,753	32,743	—	183,610
Rhoades	—	—	—	—	—

(a) The full amount shown for executive contributions is included in the base salary figures for each NEO shown above in the Summary Compensation Table.
(b) The full amount shown under registrant contributions is included in Constellation and its subsidiaries' contributions to savings plans for each NEO shown above in the All Other Compensation Table.
(c) The amount shown under aggregate earnings reflects the NEOs' gain or loss based upon the individual allocation of his notional account balance into the basket of mutual fund benchmarks. These gains or losses do not represent current income to the NEO and have not been included in any of the compensation tables shown above.
(d) For all NEOs the aggregate balance shown includes those amounts, both executive contributions and registrant contributions, that have been disclosed either as base salary as described in tickmark (a) or as Constellation and its subsidiaries' contributions under all other compensation as described in tickmark (b) for the current fiscal year ending December 31, 2021.

Potential Payments upon Termination or Change in Control

Each NEO is entitled to compensation in the event his or her employment terminates or upon a change in control. The Exelon Compensation Committee adopted changes to severance and change in control benefits effective in 2020, with the amount of benefits payable being contingent upon a variety of factors, including the circumstances under which employment terminates.

Severance Benefits

NEOs are entitled to certain payments and benefits in connection with a termination of employment other than for cause (which generally includes refusal to perform duties, willful or reckless acts or omissions, commission of a felony, a material violation of the Code of Business Conduct, or any breach of a restrictive covenant) or disability or resignation for good reason (which generally includes certain reductions in salary, demotions or material reductions in the NEO's position or duties) as provided for in the Senior Management Severance Plan ("SMSP").

The "Severance Period" is 24 months after termination of employment for Messrs. Crane, Dominguez, Hanson and Mr. McHugh. The Severance Period for Mr. Wright is 18 months. The Severance Period for Messrs. Eggers and Rhoades is 15 months. Benefits under the Plan include the following items.

Severance Pay	Continued payment of base salary for the applicable Severance Period
Annual Incentive	Target annual incentive awards for the applicable Severance Period and a pro-rated annual incentive award for the year in which the termination of employment occurs.
Equity Awards	1. *RSUs*: Unvested awards are prorated based on date of termination and vest 2. *LTIP (including performance shares):* Prorated portion vests based on actual performance; payable at the time provided for in the award terms 3. *Stock Options:* Outstanding awards are exercisable to the extent the award was exercisable on the date of termination and may be exercised until the earlier of 90 days from termination date or expiration date of award.
SMRP Benefits	Benefit equal to the amount payable under the SMRP determined as if the SMSP benefit were fully vested and the severance pay constituted covered compensation for purposes of the SMSP.
Retirement Benefits	If applicable, benefits equal to the actuarial equivalent present value of any non-vested accrued benefit under Exelon's qualified defined benefit retirement plan. All current NEOs are fully vested.
Insurance, Health and Welfare Benefits	Life, disability, accident, health and other welfare benefit coverage continues during the severance pay period on the same terms and conditions applicable to active employees, followed by retiree health coverage if applicable.[a]
Financial Planning	Outplacement and financial planning services for at least 12 months.

(a) Executives are eligible for retirement benefits, including retiree health coverage, if they are at least 55 years old and have completed at least 10 years of service.

Payments under the SMSP are subject to reduction by Exelon to the extent necessary to avoid imposition of excise taxes imposed by Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law.

Change in Control Benefits

NEOs are eligible for certain benefits upon certain involuntary terminations or a resignation for "good reason" (which generally includes certain reductions in compensation and benefits, reductions in position, duties or responsibilities, relocations or breaches by the company of the SMSP) in connection with a change in control of Exelon Corporation. Pursuant to the terms of his separation agreement, Mr. Cornew is not eligible for change in control benefits.

Under the SMSP, a "change in control" includes any of the following: (a) when any person or group acquires 20% of Exelon's then outstanding common stock or of voting securities; (b) the incumbent members of the Exelon board (or new members nominated by a majority of incumbent directors) cease to constitute at least a majority of the members of the Exelon board; (c) consummation of a reorganization, merger or consolidation, or sale or other disposition of at least 50% of Exelon's operating assets (excluding a transaction where Exelon shareholders retain at least 60% of the voting power); or (d) upon shareholder approval of a plan of complete liquidation or dissolution.

If the executive resigns for good reason or his or her employment is terminated by Exelon other than for cause or disability, during the period commencing 90 days before a change of control or during the 24-month period following a change in control, the executive is entitled to the benefits outlined below.

Severance Pay	The executive receives 2.99 times base salary (2.0 times for Mr. Wright and 1.5 times from Mr. Eggers and Mr. Rhoades) to be paid in substantially equal regular payroll installments.
Annual Incentive	Target annual incentive award for a period of 2.99 years (2.0 times for Mr. Wright and 1.5 times from Mr. Eggers and Mr. Rhoades) after termination of employment and a pro-rated annual incentive award for the year in which the termination of employment occurs.
Equity Awards	1. *RSUs:* Unvested awards vest 2. *LTIP (including performance shares):* Prorated portion vests based on actual performance; payable at the time provided for in the award terms 3. *Stock Options:* Outstanding awards are immediately exercisable and may be exercised until the earlier of 5 years from termination date or expiration date of award.
SMRP Benefits	Benefit equal to the amount payable under the SMRP determined as if (1) the executive had 18 additional months (2.99 years for Mr. Crane, Mr. Dominguez, and Mr Hanson; 2.0 times for Mr. Wright) of age and years of service and (2) the severance pay constituted covered compensation for purposes of the SMRP.
Retirement Benefits	Benefits equal to the actuarial equivalent present value of any non-vested accrued benefit under Exelon's qualified defined benefit retirement plan. All current NEOs are fully vested.
Insurance, Health and Welfare Benefits	Life, disability, accident, health and other welfare benefit coverage continues during the severance pay period on the same terms and conditions applicable to active employees, followed by retiree health coverage if applicable.[(a)]
Financial Planning	Outplacement and financial planning services for at least 12 months.

(a) Executives are eligible for retirement benefits, including retiree health coverage, if they are at least 55 years old and have completed at least 10 years of service.

2021 Estimated Value of Benefits to be Received Upon Retirement

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs, except Mr. Cornew, assuming they retired as of December 31, 2021. As of December 31, 2021, Mr. Eggers and Mr. McHugh had not reached the minimum age required to be eligible for retirement benefits. These payments and benefits are in addition to the present value of the accumulated benefits from each NEO's qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Deferred Compensation section.

Name	Cash Payment[(a)]	Value of Unvested Equity Awards[(b)]	Total Value of All Payments and Benefits[(c)]
Crane	$ 2,169,000	$ 37,613,000	$ 39,782,000
Dominguez	847,000	3,864,000	4,711,000
Cornew	—	—	—
Wright	240,000	1,669,000	1,909,000
Eggers	470,000	—	470,000
Hanson	660,000	5,969,000	6,629,000
McHugh	422,000	—	422,000
Rhoades	492,000	4,631,000	5,123,000

(a) Under the terms of the 2021 AIP, a pro-rated actual incentive award is payable upon retirement based on the number of days worked during the year of retirement. The amount above represents the executive's 2021 annual incentive payout after Company/business unit performance was determined.
(b) Includes the value of the executives' unvested performance share awards granted in 2019, 2020 and 2021 assuming target performance and the accelerated portion of the executives' RSU awards that, per applicable awards terms, would vest upon retirement. The value of the shares is based on Exelon's closing stock price on December 31, 2021 of $57.76.
(c) Estimate of total payments and benefits based on a December 31, 2021 retirement date.

2021 Estimated Value of Benefits to be Received Upon Termination due to Death or Disability

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs, except Mr. Cornew, assuming employment is terminated due to death or disability as of December 31, 2021. These payments and benefits are in addition to the present value of the accumulated benefits from the NEOs' qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Deferred Compensation section.

Name	Cash Payment[(a)]	Value of Unvested Equity Awards[(b)]	Total Value of All Payments and Benefits[(c)]
Crane	$ 2,169,000	$ 37,613,000	$ 39,782,000
Dominguez	847,000	6,175,000	7,022,000
Cornew	—	—	—
Wright	240,000	1,669,000	1,909,000
Eggers	470,000	2,949,000	3,419,000
Hanson	660,000	8,279,000	8,939,000
McHugh	422,000	6,910,000	7,332,000
Rhoades	492,000	6,942,000	7,434,000

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(a) Under the terms of the 2021 AIP, a pro-rated actual incentive award is payable upon death or disability based on the number of days worked during the year of termination. The amount above represents the executives' 2021 annual incentive payout after Company/business unit performance was determined.
(b) Includes the value of the executives' unvested performance share awards granted in 2019, 2020, and 2021 assuming target performance and the accelerated portion of the executives' RSU awards that, per applicable awards terms, would vest upon death or disability. The value of the shares is based on Exelon's closing stock price on December 31, 2021 of $57.76.
(c) Estimate of total payments and benefits based on a December 31, 2021 termination due to death or disability.

2021 Estimated Value of Benefits to be Received Upon Involuntary Separation Not Related to a Change in Control

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs assuming they were terminated as of December 31, 2021 under the terms of the SMSP. These payments and benefits are in addition to the present value of the accumulated benefits from the NEOs' qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Deferred Compensation section.

Name	Cash Payment[(a)]	Retirement Benefit Enhancement[(b)]	Value of Unvested Equity Awards[(c)]	Health and Welfare Benefit Continuation[(d)]	Perquisites and Other Benefits[(e)]	Total Value of All Payments and Benefits[(f)]
Crane	$ 8,829,000	$ 1,825,000	$ 37,613,000	$ 117,000	$ 40,000	$ 48,424,000
Dominguez	5,782,000	395,000	5,911,000	47,000	40,000	12,175,000
Cornew	—	—	—	—	—	—
Wright	1,269,000	142,000	1,669,000	26,000	40,000	3,146,000
Eggers	2,014,000	108,000	2,227,000	25,000	40,000	4,414,000
Hanson	3,343,000	1,612,000	8,234,000	41,000	40,000	13,270,000
McHugh	2,811,000	—	3,787,000	45,400	40,000	6,683,400
Rhoades	2,067,000	2,113,000	6,897,000	28,000	40,000	11,145,000

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(a) Represents the estimated cash severance benefit equal to the severance multiple times the sum of the executive's (i) current base salary and (ii) the annual incentive award at target, plus a pro-rated annual incentive award for the year in which termination occurs. The amount above represents the executives' 2021 annual incentive payout after Company/business unit performance was deter.
(b) Represents the estimated retirement benefit enhancement that consists of a one-time lump sum payment based on the actuarial present value of a benefit under the non-qualified pension plan assuming that the severance pay period was

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taken into account for purposes of vesting, and the severance pay constituted covered compensation for purposes of the non-qualified pension plan.
(c) Includes the value of the executives' unvested performance shares, which will vest upon termination at the actual level earned and awarded (it is assumed the 2019, 2020, and 2021 performance shares are earned at target) and the accelerated portion of the executives' RSUs that would vest upon an involuntary separation not related to a change in control. The value of the shares is based on Exelon's closing stock price on December 31, 2021 of $57.76.
(d) Estimated costs of healthcare, life insurance, and long-term disability coverage which continue during the severance period.
(e) Estimated costs of outplacement and financial planning services for up to 12 months for all NEOs.
(f) Estimate of total payments and benefits based on a December 31, 2021 termination date.

2021 Estimated Value of Benefits to be Received Upon a Qualifying Termination following a Change in Control

The following table shows the estimated value of payments and other benefits to be conferred upon the NEOs, except Mr. Cornew, assuming they were terminated upon a qualifying change in control as of December 31, 2021. These payments and benefits are in addition to the present value of accumulated benefits from the NEOs' qualified and non-qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Deferred Compensation section.

Name	Cash Payment[(a)]	Retirement Benefit Enhancement[(b)]	Value of Unvested Equity Awards[(c)]	Health and Welfare Benefit Continuation[(d)]	Perquisites and Other Benefits[(e)]	Potential Scaleback	Total Value of All Payments and Benefits[(f)]
Crane	$ 12,126,000	$ 2,854,000	$ 37,613,000	$ 175,000	$ 40,000	$ —	$ 52,808,000
Dominguez	8,225,000	590,000	6,175,000	70,000	40,000	—	15,100,000
Cornew	—	—	—	—	—	—	—
Wright	1,613,000	266,000	1,669,000	35,000	40,000	—	3,623,000
Eggers	2,323,000	130,000	2,949,000	30,000	40,000	(380,000)	5,092,000
Hanson	4,670,000	2,640,000	8,279,000	61,000	40,000	—	15,690,000
McHugh	3,993,000	—	6,910,000	68,000	40,000	(323,000)	10,688,000
Rhoades	2,382,000	3,177,000	6,942,000	34,000	40,000	(1,023,000)	11,552,000

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(a) Represents the estimated cash severance benefit equal to the change in control severance multiple times the sum of the executive's (i) current base salary and (ii) the annual incentive award at target, plus a pro-rated annual incentive award for the year in which termination occurs. The amount above represents the executives' 2021 annual incentive payout after Company/business unit performance was determined.
(b) Represents the estimated retirement benefit enhancement that consists of a one-time lump sum payment based on the actuarial present value of a benefit under the non-qualified pension plan assuming that the respective severance pay constituted covered compensation for purposes of the non-qualified pension plan.
(c) Includes the value of the executives' unvested performance shares, which will vest upon termination at the actual level earned and awarded (it is assumed the 2019, 2020, and 2021 performance shares are earned at target) and the accelerated portion of the executives' RSUs that would vest upon a qualifying termination following a change in control. The value of the shares is based on Exelon's closing stock price on December 31, 2021 of $57.76.
(d) Estimated costs of healthcare, life insurance and long-term disability coverage which continue during the severance period.
(e) Estimated costs of outplacement and financial planning services for up to 12 months for all NEOs.
(f) Estimate of total payments and benefits based on a December 31, 2021 termination date.

Director Compensation

The Company did not pay any compensation to directors in 2021 due to the fact that the separation from Exelon was not completed until February 1, 2022. Following the distribution, the Company's non-employee director compensation program is subject to the review and approval of the Company's board upon the recommendation of the Corporate Governance Committee. The director compensation program for the Company is designed to enable ongoing attraction and retention of highly qualified directors and to address the time, effort, expertise and accountability required of active board membership.

The non-employee director compensation program comprises cash and equity components. The following chart shows the initial annual retainers for non-employee directors as well as additional fees paid to the independent chair and committee chairs. Directors serving in multiple leadership roles will receive incremental compensation for each role.

Role	Cash	Deferred Stock Units	Total
All Directors (base retainer)	$ 125,000	$ 155,000	$ 280,000
Independent Board Chair	200,000	—	200,000
Audit Committee Chair	25,000	—	25,000
Compensation Committee Chair	20,000	—	20,000
Governance Committee Chair	20,000	—	20,000
Nuclear Oversight Committee Chair[a]	20,000	—	20,000

(a) All members of the Nuclear Oversight Committee, including the chair, receive a $20,000 retainer.

Directors do not receive additional compensation for attending regularly scheduled board or committee meetings. All board fees are paid quarterly in arrears. New directors joining the board receive a prorated fee for the quarter based on the date of their election.

Directors may elect to defer any portion of cash compensation into a non-qualified multi-fund deferred compensation plan. Under the plan, each director has an unfunded account where the dollar balance can be invested in one or more of several mutual funds. Fund balances are settled in cash and may be distributed in a lump sum or in annual installment payments upon a director reaching age 65, age 72, or upon departure from the board.

Deferred stock units earn dividend equivalents which are reinvested in the deferred stock accounts as additional stock units. The account balance of deferred stock units will be settled in shares of the Company common stock and may be distributed in a lump sum or in annual installments upon reaching age 65, age 72, or upon a director’s departure from the board.

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

The following table shows the ownership of our common stock as of February 15, 2022 by each Director and each executive officer, and for all Directors and executive officers as a group.

Directors and Named Executive Officers	Beneficial Ownership of Common Stock[(a)(b)]
Laurie Brlas	12,992
Yves de Balmann	92,949
Rhonda Ferguson	—
Bradley Halverson	—
Charles Harrington	—
Julie Holzrichter	—
Ashish Khandpur	—
Robert Lawless	111,448
John Richardson	9,463
Joseph Dominguez	121,532
Kathleen Barrón	51,740
Matthew Bauer	10,946
David Dardis	24,837
Daniel Eggers	30,341
Bryan Hanson	103,494
Michael Koehler	59,657
James McHugh	87,882
Directors & Executive Officers as a group (17 people)	717,281

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(a) Includes any shares as to which the individual has sole or shared voting or investment power, Directors' deferred stock units, officers' RSUs and deferred shares held in the Stock Deferral Plan, and Directors' and officers' phantom shares held in a non-qualified deferred compensation plan which will be settled in cash on a 1 for 1 basis upon retirement or termination.

(b) Total share interest of Directors and executive officers, both individually and as a group, represents less than 1% of the outstanding shares of our common stock.

Shown in the table below are those owners who are believed by the Company to hold more than 5% of the outstanding common stock. This information is based on the most recent Schedule 13G (or Schedule 13G/A) filed with the SEC by the following investors with respect to their ownership of Exelon common stock as of December 31, 2021, and adjusted by the distribution ratio of one share of our common stock for every three shares of Exelon used in the separation transaction from Exelon:

- BlackRock, Inc. filed on February 3, 2022;
- Wellington Management Group LLP, Wellington Group Holdings LLP, Wellington Investment Advisors Holdings LLP, and Wellington Management Company LLP jointly filed on February 4, 2022;
- The Vanguard Group filed on February 9, 2022;
- Capital International Investors filed on February 11, 2022; and
- State Street Corporation filed on February 14, 2022

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Name and Address of Beneficial Owner	Shares Beneficially Owned	Percentage of Class
The Vanguard Group[a] 100 Vanguard Blvd., Malvern, PA 19355	28,165,735	8.65 %
Wellington Management Group LLP[b] Wellington Group Holdings LLP Wellington Investment Advisors Holdings LLP c/o Wellington Management Company LLP 280 Congress Street, Boston, MA 02210	25,856,455	7.94 %
BlackRock, Inc.[c] 55 East 52nd Street, New York, NY 10055	25,125,470	7.70 %
Capital International Investors[d] 333 South Hope Street, 55th Fl, Los Angeles, CA 90071	20,222,555	6.20 %
State Street Corporation[e] State Street Financial Center One Lincoln Street, Boston, MA 02111	20,057,276	6.16 %

(a) The Vanguard Group disclosed in its Schedule 13G/A that it has shared voting power over 499,252 shares, sole dispositive power over 26,864,925 shares, and shared dispositive power over 1,300,811 shares, adjusted in each case after applying the distribution ratio of one share of our common stock for each three shares of Exelon common stock.

(b) Wellington Management Group LLP, Wellington Group Holdings LLP, Wellington Investment Advisors Holdings LLP, and Wellington Management Company LLP disclosed in their Schedule 13G/A that they have shared voting power over 24,970,079 shares and shared dispositive power over 25,856,455 shares, adjusted in each case after applying the distribution ratio of one share of our common stock for each three shares of Exelon common stock.

(c) BlackRock, Inc. disclosed in its Schedule 13G/A that it has sole power to vote or to direct the vote of 22,039,266 shares and sole power to dispose or direct the disposition of 25,720,619 shares, adjusted in each case after applying the distribution ratio of one share of our common stock for each three shares of Exelon common stock.

(d) Capital International Investors disclosed in its Schedule 13G that it has sole voting power over 20,217,549 shares and sole dispositive power over 20,222,555 shares, adjusted in each case after applying the distribution ratio of one share of our common stock for each three shares of Exelon common stock.

(e) State Street Corporation disclosed in its Schedule 13G that it has shared voting power over 15,899,278 shares and shared dispositive power over 20,043,308 shares, adjusted in each case after applying the distribution ratio of one share of our common stock for each three shares of Exelon common stock.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Related Person Transactions

We have adopted a written policy on the review, approval or ratification of transactions with related persons, which is overseen by the Corporate Governance Committee and is available on our website. The policy provides that the Committee or the Committee chair will review any proposed, existing, or completed transactions in which the amount involved exceeds $120,000 and in which any related person had, has, or will have a direct or indirect material interest. In general, related persons are directors and executive officers and their immediate family members, as well as stockholders beneficially owning 5% or more of our outstanding stock as defined in SEC rules. Our General Counsel reviews relevant information on transactions, arrangements, and relationships disclosed and makes a determination as to the existence of a related person transaction as defined by SEC rules and the policy. Related person transactions that are in, or not inconsistent with, the best interests of the Company are approved by the Corporate Governance Committee and reported to the Board. Related person transactions are disclosed in accordance with applicable SEC and other regulatory requirements.

There were no related person transactions identified for 2021.

Director Independence

Our Board of Directors has determined that all non-employee directors who serve on the Board are independent according to applicable law and the listing standards of The Nasdaq Stock Market, as incorporated into the Independence Standards for Directors in our Corporate Governance Principles. The Board also determined that the members of the Audit and Risk Committee, Compensation Committee, and Corporate Governance

Committee are independent within the meaning of applicable laws, Nasdaq governance requirements, and the Independence Standards for Directors.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Pursuant to the Audit and Risk Committee's pre-approval policy, the Committee pre-approves all audit and non-audit services to be provided by the independent auditor taking into account the nature, scope, and projected fees of each service as well any potential implications for auditor independence. The policy specifically sets forth services that the independent auditor is prohibited from performing by applicable law or regulation. Further, the Audit and Risk Committee may prohibit other services that in its view may compromise, or appear to compromise, the independence and objectivity of the independent auditor. Predictable and recurring audit and permitted non-audit services will be considered for pre-approval by the Audit and Risk Committee on an annual basis.

For any services not covered by these initial pre-approvals, the Audit and Risk Committee has delegated authority to the Committee Chair to pre-approve any audit or permitted non-audit service with fees in amounts less than $500,000. Services with fees exceeding $500,000 require full Committee pre-approval. The Audit and Risk Committee receives quarterly reports on the actual services provided by and fees incurred with the independent auditor. No services were provided pursuant to the de minimis exception to the pre-approval requirements contained in the SEC's rules.

Since we were a wholly owned subsidiary of Exelon as of December 31, 2021, for 2021 the Exelon Audit Committee reviewed the PricewaterhouseCoopers 2021 Audit Plan and proposed fees and concluded that the scope of audit was appropriate, and the proposed fees were reasonable. The following table presents the fees for professional services rendered by PricewaterhouseCoopers LLP for the audit of Constellation's annual financial statements for the years ended December 31, 2021 and December 31, 2020, and fees billed for other services provided during those periods. These fees include an allocation of amounts billed directly to Exelon. The fees include amounts related to the year indicated, which may differ from amounts billed.

	Year Ended December 31,	
(in thousands)	2021	2020
Audit fees[(a)]	$ 10,788	$ 12,236
Audit related fees[(b)]	1,080	925
Tax fees[(c)]	648	416
All other fees[(d)]	86	16
Total	$ 12,602	$ 13,593

(a) Audit fees include financial statement audits and reviews under statutory or regulatory requirements and services that generally only the auditor reasonably can provide, including SEC financial statement audits and reviews, review of documents filed with the SEC, issuance of comfort letters and consents for debt issuances and other attest services required by statute or regulation.

(b) Audit related fees consist of assurance and related services that are traditionally performed by the principal auditor and are reasonably related to the performance of the audit or review of the financial statements or other assurance services to comply with contractual requirements, financial accounting, or reporting and control consultations.

(c) Tax fees consist of tax compliance, planning and advice services, including tax return preparation, refund claims, tax payment planning, assistance with tax audits and appeals, advice related to mergers and acquisitions and transactions, or requests for rulings or technical advice from tax authorities.

(d) All other fees consist of system implementation quality assurance services and accounting research software license cost.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Constellation Energy Generation, LLC and Subsidiary Companies

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 25, 2022 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Statements of Cash Flows for the Years Ended December 31, 2021, 2020, and 2019

Consolidated Balance Sheets at December 31, 2021 and 2020

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2021, 2020, and 2019

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2021, 2020, and 2019

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Constellation Energy Generation, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2021					
Allowance for credit losses	$ 32	$ 34	$ —	$ 7 (a)	$ 59
Deferred tax valuation allowance	23	—	(1)	—	22
Reserve for obsolete materials	265	(6)	(2)	7	250
For the year ended December 31, 2020					
Allowance for credit losses	$ 81	$ 12	$ (56) (b)	$ 5 (a)	$ 32
Deferred tax valuation allowance	24	—	(1)	—	23
Reserve for obsolete materials	143	123 (c)	(1)	—	265
For the year ended December 31, 2019					
Allowance for credit losses	$ 104	$ 27	$ (11)	$ 39 (a)	$ 81
Deferred tax valuation allowance	26	—	(2)	—	24
Reserve for obsolete materials	145	—	—	2	143

(a) Write-offs, net of recoveries of individual accounts receivable.
(b) Reflects the sale of customer accounts receivable in the second quarter of 2020. See Note 6—Accounts Receivable of the Notes to Consolidated Financial Statements for additional information.
(c) Primarily reflects expense resulting from materials and supplies inventory reserve adjustments as a result of the decision to early retire Byron, Dresden, and Mystic 8 and 9. See Note 7—Early Plant Retirements of the Notes to Consolidated Financial Statements for additional information.

Exhibits required by Item 601 of Regulation S-K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2-1	Separation Agreement, dated January 31, 2022, between Exelon and Constellation (File No. 001-41137, Form 8-K dated February 2, 2022, Exhibit 2.1)
3-1	Amended and Restated Articles of Incorporation of Constellation Energy Corporation, effective January 31, 2022 (File No. 001-41137, Form 8-K dated February 2, 2022, Exhibit 3.1)
3-2	Amended and Restated Bylaws of Constellation Energy Corporation, effective January 31, 2022 (File No. 001-41137, Form 8-K dated February 2, 2022, Exhibit 3.2)
3-3	Amended and Restated Certificate of Organization, as amended, of Constellation*
3-4	Amended and Restated Operating Agreement of Constellation*
4-1	Form of 4.25% Senior Note due 2022 issued by Constellation (File No. 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.1)
4-2	Form of 5.60% Senior Note due 2042 issued by Constellation (File No. 333-85496, Form 8-K dated June 18, 2012, Exhibit 4.2)
4-3	Form of 6.000% Senior Notes due 2033 issued by Constellation (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit No. 4.1)
4-4	Indenture dated as of September 28, 2007 from Constellation to U.S. Bank National Association, as trustee (File No. 333-85496, Form 8-K dated September 28, 2007, Exhibit 4.1)
4-5	Form of 6.25% Constellation Senior Note due 2039 (File No. 333-85496, Form 8-K dated September 23, 2009, Exhibit 4.2)
4-6	Form of 4.00% Constellation Senior Note due 2020 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.1)
4-7	Form of 5.75% Constellation Senior Note due 2041 (File No. 333-85496, Form 8-K dated September 30, 2010, Exhibit 4.2)
4-8	Indenture, dated as of September 30, 2013, among Continental Wind, LLC, the guarantors party thereto and Wilmington Trust, National Association, as trustee (File No. 333-85496, Form 8-K dated September 30, 2013, Exhibit 4.1)
4-9	Form of Constellation 3.400% notes due 2022 (File No. 333-85496, Form 8-K dated March 10, 2017, Exhibit 4.2)
4-10	Form of Constellation 3.250% Senior Notes due 2025 (File No. 333-85496, Form 8-K dated May 15, 2020, Exhibit 4.1)
4-11	Indenture, dated as of February 9, 2022, between Constellation and Deutsche Bank Trust Company Americas, as trustee*
4-12	First Supplemental Indenture, dated as of February 9, 2022, between Constellation and Deutsche Bank Trust Company Americas, as trustee*
4-13	Form of Constellation 3.046% Senior Notes due 2027 (incorporated by reference to Exhibit 4.12 filed herewith)
4-14	Facility Agreement, dated as of February 9, 2022, among Constellation, Fells Point Funding Trust and Deutsche Bank Trust Company Americas, as trustee*

4-15	Letter of Credit Facility Agreement, dated February 9, 2022, among Constellation, Deutsche Bank Trust Company Americas, as administrative and collateral agent, and the various financial institutions from time to time parties thereto*
4-16	Amended and Restated Declaration of Trust of Fells Point Funding Trust, dated as of February 9, 2022*
4-17	Pledge and Control Agreement, dated as of February 9, 2022, among Fells Point Funding Trust, Constellation, Deutsche Bank Company Americas, as collateral agent and securities intermediary*
10-1	Transition Services Agreement, dated January 31, 2022, between Exelon and Constellation (File No. 001-41137, Form 8-K dated February 2, 2022, Exhibit 10.1)
10-2	Tax Matters Agreement, dated January 31, 2022, between Exelon and Constellation (File No. 001-41137, Form 8-K dated February 2, 2022, Exhibit 10.2)
10-3	Employee Matters Agreement, dated January 31, 2022, between Exelon and Constellation (File No. 001-41137, Form 8-K dated February 2, 2022, Exhibit 10.3)
10-4	Credit Agreement, dated as of November 28, 2017, as thereafter amended and conformed among Constellation Renewables, LLC, Constellation Renewables Holding, LLC, Morgan Stanley Senior Funding, Inc. as administrative agent, Wilmington Trust, National Association, as depository bank and collateral agent, and the lenders and other agents party thereto. (Certain portions of this exhibit have been omitted by redacting a portion of text, as indicated by asterisks in the text. This exhibit has been filed separately with the U.S. Securities and Exchange Commission pursuant to a request for confidential treatment.) (File No. 001-16169, Form 10-K dated February 9, 2018, Exhibit 10.94)
10-5	Receivables Purchase Agreement, dated as of April 8, 2020, among Constellation NewEnergy, Inc. as servicer, and NewEnergy Receivables LLC, as seller, MUFG Bank, LTD., as Agent, the Conduits party thereto, the Financial Institutions party thereto and the Purchaser Agents party thereto (File No. 001-16169, Form 8-K dated April 9, 2020, Exhibit 10.1)
10-6	Credit Agreement, among Constellation Renewables, LLC, the lenders party thereto, Jefferies Finance LLC, as administrative agent, and Wilmington Trust, National Association, as depositary bank and collateral agent, dated December 15, 2020 (File No. 333-85496, Form 8-K dated December 15, 2020, Exhibit 1.1)
10-7	Amendment No. 2 to Receivables Purchase Agreement, dated as of March 29, 2021, among Constellation NewEnergy, Inc., as servicer, and NewEnergy Receivables LLC, as seller, MUFG Bank, LTD., as agent, the Conduits party thereto, the Financial Institutions party thereto and the Purchaser Agents party thereto (File No. 001-16169, Form 8-K, dated March 31, 2021, Exhibit 10.1)
10-8	Settlement Agreement, dated August 6, 2021, between Constellation and EDF Inc. (File No. 333-85496, Form 10-Q dated November 3, 2021, Exhibit 10.1)
10-9	364-Day Term Loan Credit Agreement, dated August 6, 2021, between Generation and Barclays Bank PLC (File No. 333-85496, Form 10-Q dated November 3, 2021, Exhibit 10.2)
10-10	$3,500,000,000 Credit Agreement dated as of February 1, 2022, among Constellation, JPMorgan Chase Bank, N.A., as Administrative Agent, and various financial institutions, as lenders*
10-11	Constellation Energy Corporation Non-Employee Deferred Stock Unit Plan*
10-12	Constellation Energy Corporation Unfunded Deferred Compensation Plan for Directors*
10-13	Constellation Energy Group Deferred Compensation Plan for Non-Employee Directors*
10-14	Constellation Energy Corporation Senior Management Severance Plan*
10-15	Constellation Energy Corporation Deferred Compensation Plan*
10-16	Constellation Energy Corporation Supplemental Management Retirement Plan*
10-17	Constellation Energy Corporation PECO Supplemental Pension Benefit Plan*

10-18	Constellation Energy Group Nonqualified Deferred Compensation Plan*
10-19	Constellation Energy Group Benefits Restoration Plan*
10-20	Constellation Energy Corporation Supplemental Pension Plan*
10-21	Constellation Energy Corporation Long-Term Incentive Plan*
10-22	Constellation Energy Corporation Employee Stock Purchase Plan*
10-23	Form of Restricted Stock Unit Retention Award under the Constellation Energy Corporation Long-Term Incentive Plan*
10-24	Form of Restricted Stock Unit Award under the Constellation Energy Corporation Long-Term Incentive Plan*
10-25	Form of Performance Share Award under the Constellation Energy Corporation Long-Term Incentive Plan*
10-26	Form of Separation Agreement under the Constellation Energy Corporation Senior Management Severance Plan*
	Subsidiaries
21-1	Constellation Energy Corporation
21-2	Constellation Energy Generation, LLC
	Consent of Independent Registered Public Accountants
23-1	Constellation Energy Corporation
	Power of Attorney (Constellation Energy Corporation)
24-1	Laurie Brlas
24-2	Yves C. de Balmann
24-3	Rhonda Ferguson
24-4	Bradley Halverson
24-5	Charles Harrington
24-6	Julie Holzrichter
24-7	Ashish Khandpur
24-8	Robert Lawless
24-9	John Richardson

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2021 filed by the following officers for the following registrants:

Exhibit No.	Description
31-1	Filed by Joseph Dominguez for Constellation Energy Corporation
31-2	Filed by Daniel L. Eggers for Constellation Energy Corporation
31-3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
31-4	Filed by Daniel L. Eggers for Constellation Energy Generation, LLC

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2021 filed by the following officers for the following registrants:

Exhibit No.	Description
32-1	Filed by Joseph Dominguez for Constellation Energy Corporation
32-2	Filed by Daniel L. Eggers for Constellation Energy Corporation
32-3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
32-4	Filed by Daniel L. Eggers for Constellation Energy Generation, LLC
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.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith.

ITEM 16. FORM 10-K SUMMARY

We may voluntarily include a summary of information required by Form 10-K under this Item 16. We have elected not to include such summary information.

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, in the City of Baltimore and State of Maryland on the 25th day of February, 2022.

CONSTELLATION ENERGY CORPORATION

By:	/s/ JOSEPH DOMINGUEZ
Name:	Joseph Dominguez
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 25th day of February, 2022.

Signature	Title
/s/ JOSEPH DOMINGUEZ Joseph Dominguez	President and Chief Executive Officer (Principal Executive Officer)
/s/ DANIEL L. EGGERS Daniel L. Eggers	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER Matthew N. Bauer	Senior Vice President and Controller (Principal Accounting Officer)

This annual report has also been signed below by David Dardis, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Laurie Brlas
Yves C. de Balmann
Rhonda Ferguson
Bradley Halverson
Charles Harrington
Julie Holzrichter
Ashish Khandpur
Robert Lawless
John Richardson

By:	/s/ DAVID DARDIS	February 25, 2022
Name:	David Dardis	

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, in the City of Baltimore and State of Maryland on the 25th day of February, 2022.

CONSTELLATION ENERGY GENERATION, LLC

By:	/s/ JOSEPH DOMINGUEZ
Name:	Joseph Dominguez
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 25th day of February, 2022.

Signature	Title
/s/ JOSEPH DOMINGUEZ Joseph Dominguez	President and Chief Executive Officer (Principal Executive Officer)
/s/ DANIEL L. EGGERS Daniel L. Eggers	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER Matthew N. Bauer	Senior Vice President and Controller (Principal Accounting Officer)