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, 2022
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 (833) 883-0162	87-1210716
333-85496	CONSTELLATION ENERGY GENERATION, LLC (a Pennsylvania limited liability company) 200 Exelon Way Kennett Square, Pennsylvania 19348-2473 (833) 883-0162	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. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2022 was as follows:

Constellation Energy Corporation	$18,711,601,222
Constellation Energy Generation, LLC	Not applicable

The number of shares outstanding of each registrant's common stock as of January 31, 2023 was as follows:

Constellation Energy Corporation Common Stock, without par value	327,131,082
Constellation Energy Generation, LLC	Not applicable

Documents Incorporated by Reference

Portions of the Registrants' Definitive Proxy Statement relating to the 2023 Annual Meeting of Shareholders are incorporated by reference into Part III of this report. The Registrants expect to file the Definitive Proxy Statement with the Securities and Exchange Commission within 120 days after December 31, 2022.

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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
Antelope Valley	Antelope Valley Solar Ranch One
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
RPG	Renewable Power Generation, LLC
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility

Former Related Entities

Exelon	Exelon Corporation
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
BSC	Exelon Business Services Company, LLC

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ABO	Accumulated Benefit Obligation
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AOCI	Accumulated Other Comprehensive Income (Loss)
APBO	Accumulated Post-Retirement Benefit Obligation
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASA	Asset Sale Agreement
Atomic Energy Act	Atomic Energy Act of 1954, as amended
Bcf	Billion cubic feet
Brookfield Renewable	Brookfield Renewable Partners, L.P.
CAISO	California ISO
CBAs	Collective Bargaining Agreements
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CES	Clean Energy Standard
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
CPP	Clean Power Plan
CTV	Constellation Technology Ventures
DCPSC	District of Columbia Public Service Commission
DEPSC	Delaware Public Service Commission
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortization
EDF	Electricite de France SA and its subsidiaries
EFEC	Emissions-Free Energy Certificate
EMT	Everett Marine Terminal
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESG	Environmental, Social, and Governance
ERP	Enterprise Resource Program
EV	Electric Vehicle
Federal Power Act	Federal Power Act of 1920, as amended
FERC	Federal Energy Regulatory Commission
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
IRA	Inflation Reduction Act of 2022
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
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
MRV	Market-Related Value
MPSC	Missouri Public Service Commission
MW	Megawatt
MWh	Megawatt hour
N/A	Not applicable
NAV	Net Asset Value
NASDAQ	Nasdaq Stock Market, Inc.
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NEPA	National Environmental Policy Act of 1969
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange, Inc.
NJBPU	New Jersey Board of Public Utilities
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
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits

PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PCAOB	Public Company Accounting Oversight Board
PBO	Projected Benefit Obligation
Pension Protection Act (the Act)	Pension Protection Act of 2006
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
PTC	Production Tax Credit
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
RMP	Risk Management Policy
RNF	Revenue Net of Purchased Power and Fuel Expense
RNG	Renewable Natural Gas
ROE	Return on equity
ROU	Right-of-use
RPS	Renewable Energy Portfolio Standards
RTO	Regional Transmission Organization
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOFR	Secured Overnight Financing Rate
SOS	Standard Offer Service
SPP	Southwest Power Pool
SSA	Social Security Administration
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

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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 by the Registrants.

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 (the "Separation"). 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.

Unless otherwise indicated or the context otherwise requires, references herein to the terms "we," "our," "us" and "the Company" refer collectively to CEG Parent and Constellation. See Glossary for defined terms.

Our Business

We are the nation's largest producer of carbon-free energy and a leading supplier of energy products and services to businesses, homes, community aggregations and public sector customers across the continental United States, including three-fourths of Fortune 100 companies. Our generation fleet of nuclear, hydro, wind, natural gas, and solar generation facilities has the generating capacity to power the equivalent of 15 million homes, producing 11 percent of the carbon-free energy in the United States. Constellation's fleet is helping to accelerate the nation's transition to a carbon-free future with more than 32,355 megawatts of capacity and an annual output that is nearly 90 percent carbon-free. This makes 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 employ approximately 13,370 people, and do business in 48 states, the District of Columbia, Canada, and the United Kingdom.

Our generation fleet produces more clean, carbon-free energy than any other company in the United States. 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. Our customer-facing business is one of the nation's largest competitive energy suppliers, offering innovative solutions 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 MWs. 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, 2022, our generating resources consisted of the following:

Type of Capacity	MWs
Owned generation assets[(a)]	
Nuclear	20,895
Natural gas and oil	8,807
Renewable[(b)]	2,653
Owned generation assets	32,355
Contracted generation[(c)]	3,883
Total generating resources	36,238

(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 owned generation facilities as of December 31, 2022:

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

ceg-20221231_g1.jpg

Owned Assets[(b)]

Nuclear Wind
Gas/Other Solar
Hydro

(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 (MWs)[(a)]	% of Net Generation Capacity	Geographical Area
Mid-Atlantic	10,495	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	11,892	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	3,265	10 %	New England, South, West, and Canada
Total	32,355	100 %	

(a) Net generation capacity is stated at proportionate ownership share as of December 31, 2022. See ITEM 2. PROPERTIES for additional information.

The following table shows sources of electric supply in GWhs for 2022 and 2021:

	Source of Electric Supply	
	2022	2021
Nuclear[(a)(b)]	173,350	172,990
Purchases — non-trading portfolio	70,682	67,605
Natural gas and oil	21,563	19,960
Renewable[(c)]	6,049	6,577
Total Supply	271,644	267,132

(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) 2021 values have been revised from those previously reported to correctly reflect our 82% undivided ownership interest in Nine Mile Point Unit 2.
(c) Includes wind, hydroelectric, solar, and in 2021, biomass generating assets. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the sale of our biomass facility.

Nuclear Facilities

Our nuclear fleet is the nation's largest, with current generating capacity of approximately 21 gigawatts; it produced 173 terawatt hours of zero-emissions electricity during 2022 – enough to power 15.4 million homes and avoid more than 123 million metric tons of carbon emissions according to the EPA GHG Equivalencies Calculator. We have ownership interests in 13 nuclear generating stations currently in service, consisting of 23 units. As of December 31, 2022, 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 consolidated 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 owned 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 22 — Variable Interest Entities of the Combined 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 2022, 2021, and 2020, our nuclear generating facilities achieved capacity factors[a] of 94.8%, 94.5%, and 95.4%, respectively, at ownership percentage. 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 2022, we achieved an average refueling outage duration of 21 days for units we operate. We achieved an average refueling outage duration of 22 days in both 2021 and 2020, against industry averages of 32 and 34 days, respectively.

We manage our scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable supply position for our wholesale and retail power marketing activities. In 2022, 2021, and 2020, electric supply (in GWhs) generated from our nuclear generating facilities was 64%, 65%, and 62%, 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 previously received a second 20-year license renewal from the NRC, for a total 80-year term, for Units 2 and 3. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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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[(b)]	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[(c)]	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040

(a) Denotes year in which nuclear unit began commercial operations.
(b) We are currently seeking license renewals for Clinton and Dresden Units 2 and 3 to extend the operating licenses by an additional 20 years.
(c) In February 2022, the NRC issued an order related to its review of our subsequent license renewal application for Peach Bottom and the NRC directed its staff to change the expiration dates for the licenses back to 2033 and 2034. We expect that the license expiration dates will be restored to 2053 and 2054, respectively, See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The operating license renewal process takes approximately four years from commencement, 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 generally correspond with the term of the NRC operating licenses denoted in the table above as of December 31, 2022, except for Clinton, Dresden and Peach Bottom. We are currently seeking license renewals for our Clinton and Dresden units. Clinton depreciation provisions are based on an estimated useful life through 2047. Dresden Units 2 and 3 depreciation provisions are based on an estimated useful life through 2049 and 2051, respectively, in anticipation of the license renewals. Peach Bottom Units 2 and 3 depreciation provisions are based on an estimated useful life through 2053 and 2054 respectively, in anticipation of the license expiration dates being restored. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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 Combined Notes to Consolidated Financial Statements for additional information on Byron and Dresden and the Illinois CMC program.

Natural Gas, Oil and Renewable Facilities (including Hydroelectric)

We operate approximately 11 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 4; (2) certain wind project entities; and (3) CRP, which is owned 49% by another unrelated party. We operate all of these facilities, except for Wyman 4, 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 22 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding CRP, which is a VIE.

In 2022, 2021, and 2020, electric supply (in GWhs) generated from our owned natural gas, oil, and renewable generating facilities was 10%, 10%, and 9%, respectively, of our total electric supply. Much of this output was dispatched to support our wholesale and retail power customer-facing activities. Our natural gas, oil and renewable fleet has similarly demonstrated a track record of strong performance with a power dispatch match[(a)] of 98.4%, 72.4%, and 98.4% and renewables energy capture[(b)] of 95.8%, 95.7%, and 93.4% in 2022, 2021, and 2020, 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 of the Combined Notes to Consolidated Financial Statements 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 is currently being depreciated over the estimated useful life, which corresponds with the available license term. In March 2021, FERC issued a new 50-year license for Conowingo, vacated in December 2022 on remand, however depreciation provisions continue to assume an estimated useful life through 2071 in anticipation of the license expiration date being restored. See Note 3 — Regulatory Matters of the Combined 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 of the Combined Notes to Consolidated Financial Statements 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 total actual energy revenue net of fuel cost relative to the total desired energy revenue net of fuel cost. Factors having an adverse effect on Dispatch Match include forced outages, derates, and failure to operate to the desired generation signal.

(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, with adjustments made for certain events that are considered non-controllable, such as force majeure events, serial design-manufacturing equipment failures, and transmission curtailments. Energy capture for the combined wind and solar fleet is weighted by the relative site projected pre-tax variable revenue.

Contracted Generation

In addition to energy produced by owned generation assets, we source electricity from generators 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, 2022:

Region	Number of Agreements	Expiration Dates	Capacity (MWs)
Mid-Atlantic	6	2023 - 2035	279
Midwest	3	2026 - 2032	351
New York	4	2023	26
ERCOT	6	2026 - 2035	841
Other Power Regions	12	2023 - 2037	2,386
Total	31		3,883

	2023	2024	2025	2026	2027	Thereafter	Total
Capacity Expiring (MW)	140	101	490	398	5	2,749	3,883

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, public sector, and residential customers in markets across multiple geographic regions. We serve approximately 2 million total customers, including three-fourths of Fortune 100 companies, and approximately 1.6 million unique residential customers.

We are a leader in electric power supply, serving approximately 208 TWhs in 2022 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:

2022 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, and 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 located 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 retail customers, trades on commodity exchanges, and sales to wholesale counterparties in accordance with 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 2022, we served approximately 65 TWhs of power load across competitive utility load procurement 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 increased customer demand for sustainability, our ability to source contracted generation has provided a capital-light way for us to provide customers with the sustainable solutions 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 energy suppliers for all retail customers (commercial, industrial and residential) to partial retail competition available up to a capped amount for C&I customers only. We are a leader in retail markets, serving approximately 143 TWhs of electric power retail load and 800 Bcf of gas in 2022, primarily to 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. Retail customer renewal rates have been strong over the last six years across C&I power customer groups, with an average contract term of approximately two years and customer duration of more than six years, with many customers well beyond these metrics. Specifically, we enjoyed renewal rates of 79% for C&I power customers and 90% for C&I gas customers in 2022, higher than the previous five 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 delivering focused attention to our customers' needs, resulting in industry-leading customer satisfaction. We are also successful at acquiring new customers by offering innovative services and products that meet their needs. In addition to our high customer renewal rates, we have produced consistently 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 four 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 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 32% of the C&I 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, that 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 solutions 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 service offerings 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.

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

In addition to sustainability products and services, data and analytics have also become increasingly important for our customers. Our smart utility expense management platform helps customers proactively manage utility costs, understand trends, and develop strategies to optimize spend and drive sustainability objectives. This platform 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. These types of data and analytical services allow us to grow our customer base in previously inaccessible regulated markets by offering non-commodity energy-related 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, financing solutions, 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, all with credit-approved counterparties, to hedge the commodity price risk of the generation portfolio.

For merchant generation sales not already hedged via comprehensive state programs, such as the CMC program in Illinois, we typically utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant sales are hedged on an approximate rolling 90%/60%/30% basis, providing cash flow stability while still allowing commercial opportunities to generate value for the Company. We may also enter transactions that are outside of this ratable hedging program. We are exposed to commodity price risk for the portions of our electricity portfolio that are unhedged. As of December 31, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% and 75%-78% for 2023 and 2024, 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 and is not material to our results. 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, including contracts sourced from Russia, and contracted fuel fabrication services. We have inventory in various forms and engage a diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term 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 manage various risks around our nuclear fuel requirements in accordance with our fuel procurement policy. The size of our inventory holdings and forward contractual coverage considers our refueling needs across multiple years to protect against supply disruptions and near-term price volatility, while allowing for capital flexibility. We engage a diverse set of domestic and international suppliers and limit our transactions with each supplier to mitigate concentration of risk. Refer to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

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 Combined 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 Combined 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 Combined 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 distinct 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, returning value to our shareholders, and investing in clean energy and sustainable solutions.

As environmental sustainability continues to build momentum for businesses across the country, the demand for carbon-free and sustainability solutions increases. We are committed to a carbon-free energy future and 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. We will 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.

We are committed to reducing our GHG emissions and enabling our C&I customers through 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.

The principles of our sustainable business strategy demonstrate our commitment to a carbon-free future while maintaining a strong balance sheet, advancing our ESG initiatives and investing in clean energy solutions.

Power America's Clean Energy Future. We will operate and grow the nation's largest fleet of clean, zero-emissions generation facilities, with world-class levels of safety, reliability and resiliency.

Expand America's Largest Fleet of Clean Energy Centers. We will leverage and expand our state-of-the-art clean energy assets by exploring co-location of customer load, direct air capture of CO2, and producing clean hydrogen and other sustainable fuels to reduce industrial emissions.

Uplift and Strengthen our Communities. We will advance respect, belonging, diversity and equity by driving community investment and creating family-sustaining clean energy jobs.

Provide Energy and Sustainability Solutions for Customers. We will provide reliable, resilient energy and deliver innovative sustainability solutions that help customers achieve their clean energy goals.

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 meet investment grade credit targets, with incremental capital allocated towards disciplined growth and shareholder return. We will build upon a strong compliance and risk management foundation 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.

Growth Opportunities. We continually evaluate growth opportunities aligned with our businesses, assets, and markets leveraging our expertise in those areas and offering durable 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, and
- 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. These governmental and corporate policies support the retention and expansion of carbon-free generation and the development and use of clean fuels like hydrogen. 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 climate goals at both the state and federal levels.

Policy Support for Nuclear Energy. As decarbonization accelerates, we expect our generation fleet will continue to 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. Through enactment of the nuclear PTC in the IRA, federal policymakers have recognized the need to ensure the continued operation of the nation’s nuclear power plants. This federal support builds on actions taken by states 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, hydrogen production, and direct air capture could result in U.S. electricity demand to more than double from what it is today by 2050. Although EV sales in North America are well behind Europe and China, increased policy support through the IRA and other federal and state policies, 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. A 2022 Rhodium Group study forecasts that as much as 57% of light duty vehicles sold in 2030 will be electric. 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. 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 solutions 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 have undertaken our first employee engagement survey as a company and will use it and future surveys to help identify our successes and opportunities for growth. The survey results are shared with leaders at all levels and they are also part of action planning to increase engagement.

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. Additionally, we develop our employees through individual discussions, mentorship programs, 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 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

We are committed to helping our employees maintain and improve their health and wellness, and we offer a wide range of benefits designed to help our employees thrive professionally and personally. We take a holistic approach to health and wellness, providing support for our employees' physical health, mental well-being, family, as well as financial and legal strength.

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 and charitable matching gifts programs. Our employees donated $4.6 million to non-profit organizations and provided just over 80,000 volunteer hours in 2022.

Next Generation of Talent

We are also committed to exposing underrepresented and underserved individuals within our communities to career opportunities in the energy industry. Through internships and scholarships, university and veteran recruiting, STEM education and training programs, and partnerships with diverse talent organizations such as the Society of Women Engineers and the National Society of Black Engineers, we are committed to providing equitable access to professional development and opportunities for the next generation of our workforce.

Major focus areas include:

- Creating educational and awareness opportunities within STEM and the trades through curriculum development, early engagement, and educational partnerships,
- Reducing or removing access and opportunity barriers faced by young people and underrepresented and underserved members of the community, and
- Deepening current and executing new approaches and partnerships with industry employers, nonprofits, and community groups to provide entry and advancement opportunities for work-ready adults and youth through upskilling and reskilling training efforts.

Diversity Metrics

The following table shows diversity metrics for all employees and management as of December 31, 2022:

Metric	All Employees	Management[d]
Female[a][b]	2,889	474
People of Color[a][b]	2,569	331
Aged <30	1,680	50
Aged 30-50	7,420	1,474
Aged >50	4,270	855
Within 10 years of retirement eligibility	5,724	1,197
Total Employees[c]	13,370	2,379

(a) We conduct an annual analysis on gender and racial pay equity. We also review hiring and promotion processes to neutralize any unconscious bias and embed equal pay efforts into broader company-wide equity initiatives. These actions reflect our commitment to create an environment where all employees can thrive and advance as equal members of the workforce.
(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 2020 to 2022:

	All
Retirement Age	4.30 %
Voluntary	6.00 %
Non-Voluntary	1.20 %

Collective Bargaining Agreements

Approximately 25% of employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2022:

Total Employees Covered by CBAs	Number of CBAs	CBAs New and Renewed in 2022[(a)]	Total Employees Under CBAs New and Renewed in 2022
3,342	21	1	74

(a) Does not include CBAs that were extended in 2022 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, our Sustainability and Climate Strategy team, and other members of 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. Independent of additional legislation, we support the 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 2021 were 8.3 million metric tons carbon dioxide equivalent, of which 8.0 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) and neither own nor operate any coal-fueled generating assets. Our natural gas and oil generating plants produce GHG emissions, most notably CO_2. In addition, we sell natural gas through our customer-facing business; and consumers' use of such natural gas produces GHG emissions. However, our owned-asset emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. In 2022, we achieved a 94.8% percent capacity factor across our nuclear fleet and our ownership of 21 gigawatts of carbon-free generation capacity at 23 nuclear units produced 173 TWhs of electricity in 2022.

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. The most recent Conference of Parties (COP27) held in Sharm el-Sheikh, Egypt recommitted countries to their pledges in the Glasgow Climate Pact.

Federal Climate Change Legislation. On August 16, 2022, the U.S. Congress passed and President Biden signed into law the Inflation Reduction Act of 2022, which, among other things, includes federal tax credits, certain of which are transferable or fully refundable, for clean energy technologies including existing nuclear plants and hydrogen production facilities. The Nuclear PTC recognizes the contributions of carbon-free nuclear power by providing a federal tax credit of up to $15 per MWh, subject to phase-out, beginning in 2024 and continuing through 2032. The Hydrogen PTC provides a 10-year federal tax credit of up to $3 per kilogram for clean hydrogen produced after 2022 from facilities that begin construction prior to 2033. Both the Nuclear and Hydrogen PTCs include adjustments for inflation. The Hydrogen PTC creates additional opportunities for our nuclear fleet to enable decarbonization of other industries through the production of clean hydrogen. With this policy support, we expect that many of our nuclear assets will operate through the end of the Nuclear PTC period. The U.S. Department of Treasury has begun the process of issuing guidance on the relevant tax provisions included in the legislation.

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 shifting generation from higher-emitting units to lower- or zero-emitting units. In July 2019, the EPA published the Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines based on heat rate improvement measures. 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. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the Affordable Clean Energy Rule. On October 29, 2021, the U.S. Supreme Court granted certiorari to examine the extent of the EPA's authority to regulate GHGs from power plants. The electric utilities coalition filed a brief and participated in oral argument before the U.S. Supreme Court. On June 30, 2022, the U.S. Supreme Court issued a decision holding that the EPA did not have the authority to require "generation shifting" from coal to natural gas and renewables to reduce sector-wide emissions, as it had done in CPP. The remainder of the litigation was remanded to the U.S. Court of Appeals for the D.C. Circuit and held in abeyance in light of forthcoming actions from the EPA. The EPA has indicated it will propose new GHG limits for power plants in April 2023 and finalize them in 2024.

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 53% 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.

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 preserve the environmental attributes of our nuclear facilities, and include the following:

Policy Name	Year Enacted	Nuclear Facilities Impacted	Type of Program	Year of Expiration
New York Clean Energy Standard	2016	FitzPatrick, Ginna, and NMP	ZEC	2029
Illinois Zero Emission Standard	2016	Clinton and Quad Cities	ZEC	2027
New Jersey Clean Energy Legislation	2018	Salem	ZEC	2025
Illinois Clean Energy Law	2021	Byron, Braidwood, and Dresden	CMC	2027

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

Regional Greenhouse Gas Initiative. On July 1, 2022, Pennsylvania formally began participation in RGGI, joining Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia. The program requires most fossil fuel-fired power plants in the region to hold allowances, sold at auction or on the secondary market, for each ton of CO_2 emissions. Non-emitting resources do not have to purchase or hold these allowances. Pennsylvania's participation in RGGI was accomplished through a PA DEP regulation that became effective on July 1, 2022 that was challenged in the Commonwealth Court of Pennsylvania, which has enjoined the state from implementing the regulation pending resolution of the proceeding. The Commonwealth Court of Pennsylvania heard oral arguments in November 2022 on the merits of the challenges to Pennsylvania entering RGGI. In the interim, the state has petitioned the Pennsylvania Supreme Court to vacate the lower court's injunction order. Briefing of the appeal was completed on December 4, 2022.

On January 15, 2022, Governor Youngkin directed the Virginia Department of Environmental Quality to reevaluate the state's participation in RGGI and begin a regulatory process to consider repeal of the regulations providing for RGGI participation. On September 26, 2022, the Virginia State Air Pollution Control Board published a Notice of Intended Regulatory Action seeking public comment on the proposed repeal of the state's regulations implementing its participation in RGGI. This matter remains pending.

Renewable and Clean Energy Standards. 31 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 certificates (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 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 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 U.S. 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 lawsuit in the D.C. Circuit sought vacatur of MATS based on the EPA's May 22, 2020 finding; on September 11, 2020, the Court granted a motion by Exelon and two other entities to intervene in that lawsuit to defend MATS, and on September 28, 2020, the Court held this portion of the litigation in abeyance. On July 21, 2020, we, as part of Exelon, and two other entities filed a lawsuit in the D.C. Circuit challenging the EPA's May 22, 2020 rescission of the “appropriate and necessary” finding. On January 20, 2021, President Biden issued an Executive Order directing the EPA to reconsider its May 22, 2020, revised supplemental finding, and the EPA subsequently moved for the D.C. Circuit to place the cases challenging that finding in abeyance pending its reconsideration, which the court did on February 21, 2021. On February 9, 2022 the EPA published a proposal to revoke the 2020 revised supplemental finding and reaffirm that it is "appropriate and necessary" to regulate hazardous air pollutant emissions from coal- and oil-fired power plants. Additionally, in February 2022, the D.C. Circuit granted unopposed motions to substitute Constellation in place of Exelon in these cases. The EPA has indicated that they will issue the final regulation in March 2023. If the EPA promulgates a final rule revoking the 2020 revised supplemental finding determination, then the cases currently before the D.C. Circuit concerning MATS may be dismissed as moot or placed in abeyance pending the disposition of any petitions for review that may be filed challenging that final rule. We cannot reasonably predict the outcome of this matter.

Good Neighbor Rule. On April 6, 2022, the EPA published a proposed rule called “Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards” also known as the "Good Neighbor Rule" or the "Transport Rule". The proposed rule, among other things, established nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 25 states to participate in an allowance-based ozone season trading program beginning in 2023. Comments on the proposed rule were due June 6, 2022 and the EPA has indicated it will issue a final rule in early 2023. When the EPA finalizes this proposed rule, there may be impacts on the electric power market. We cannot reasonably predict the outcome of this rule.

Oil and Gas Methane Rule. On December 6, 2022, the EPA published a supplemental proposed rule setting methane emissions standards for certain new and existing oil and gas facilities. The supplemental proposal updates the proposed regulation issued in November 2021. Comments on the proposed regulation were due on February 13, 2023. When the EPA finalizes this proposed rule, there may be indirect impacts on the electric power market through the supply of gas. We cannot reasonably predict the outcome of this rule.

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 consolidated 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 authorizes response to releases or threatened releases of hazardous substances into the environment. CERCLA authorities complement those of the RCRA, which primarily regulates ongoing hazardous waste handling and disposal. 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 substances at sites, many of which are listed by the EPA on the National Priorities List. 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 Illinois, Maryland, New Jersey, and Pennsylvania. 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 or transported 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, 2022, 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 Combined Notes to 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, 2022, we had approximately 91,500 SNF assemblies (22,400 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 have on-site dry cask storage. 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 each of our sites for the duration of both current and subsequent license periods of all stations 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 Combined 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 duration of both current and subsequent license periods for all the 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 2040 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 duration of both current and subsequent license periods for of all the stations in our nuclear fleet and, we continue to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize on-site storage and cost impacts.

Corporate Information

CEG Parent's principal executive office is located at 1310 Point Street, Baltimore, Maryland 21231-3380. Constellation's principal executive office is located at 200 Exelon Way, Kennett Square, Pennsylvania 19348-2473. The telephone number for our principal executive offices is (833) 883-0162. We maintain a website located at www.ConstellationEnergy.com. The information contained on, or accessible from, our website is not part of this annual report by reference or otherwise.

Available Information

We file our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports with the SEC. You may obtain copies of these documents by accessing the SEC's website at www.sec.gov. In addition, as soon as reasonably practicable after such materials are furnished to the SEC, we make copies of these documents available to the public free of charge through our website or by contacting our corporate secretary at the applicable address set forth above under "—Corporate Information."

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,
- 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, 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 the need to replicate certain services provided by Exelon (e.g. information technology), 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 Market and Financial Factors

We are exposed to price volatility associated with both the wholesale and retail power markets and the procurement of nuclear, natural gas and oil.

We are exposed to commodity price risk for natural gas and the unhedged portion of our generation 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, natural gas and oil 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 and Ukraine conflict and the potential for additional United States sanctions against Russia. The cycle of production and utilization of nuclear fuel is complex, and we engage a diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term. Non-performance by these suppliers could have a material adverse impact on our consolidated financial statements. See ITEM 1. BUSINESS – Price and Supply Risk Management and See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information on the nuclear fuel cycle and procurement.

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.

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 may be adversely affected by the effects of sustained inflation.

The existence of inflation in the economy has resulted in, or may result in, higher interest rates and capital costs, increased costs of labor, and other similar effects. If inflation rates continue to rise or remain elevated for a sustained period, they could have a material adverse effect on our business, financial condition, results of operations and liquidity. Although we may take measures to mitigate the impact of inflation, those measures may not be effective.

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 broader 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 Combined 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 effectively hedge 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, 2022, approximately 38%, 13%, and 19% 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 and Cash Requirements – 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. See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

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 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 cost-effectively meet 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 (i.e. recession) 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 in 2020 and future pandemics or other significant health issues could also adversely affect our results.

COVID-19 has previously 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 years ended December 31, 2021 and 2022. Any future widespread pandemic or other local or global health issue could adversely affect customer demand and our ability to operate our generation assets.

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. As a result of this weather event, we incurred a loss of approximately $800 million for the year ended December 31, 2021. By comparison, the estimated impact reduced our overall Net loss by approximately $50 million for the year ended December 31, 2022, see Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined 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 Consolidated Balance Sheets.

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 Combined 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. 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.

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 Combined 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 70% 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. Federal or state legislative and regulatory efforts to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities 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 Combined 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 Combined Notes to 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 Combined Notes to 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 operating 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 operating 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 operating revenues and incur increased purchased power and fuel 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. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding the license renewal for the Conowingo hydroelectric project.

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 — Basis of Presentation and Note 14 — Income Taxes of the Combined 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 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined 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 in the future a fee for SNF disposal may be reestablished or to what extent.

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 our 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 accidental outage 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 $13.7 billion limit for a single incident.

See Note 19 — Commitments and Contingencies of the Combined 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.

Actual costs to decommission our nuclear facilities may substantially exceed our estimates as a result of changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in federal or state regulatory requirements, 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 consolidated 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 may be temporarily suspended or 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 Combined 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. We expect these attacks and disruptions to continue to occur in the future and we are constantly managing efforts to infiltrate and compromise our physical assets and information technology systems and data.

A security breach, including physical or electronic break-ins, computer viruses, malware, attacks by hackers, ransomware attacks, phishing attacks, supply chain attacks, breaches due to employee error or misconduct and other similar breaches, 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. Furthermore, in the future, such insurance may not be available on commercially reasonable terms, or at all.

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, operating licenses, 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

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.

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, 2022:

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MWs)[(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)
Harvest	Huron Co., MI	31	51 (g)	Wind	Intermittent	26 (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	5
Total Midwest						11,892
Mid-Atlantic						
Limerick	Sanatoga, PA	2		Uranium	Base-load	2,315
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	993 (f)
Conowingo	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Oakland, MD	28	51 (g)	Wind	Intermittent	36 (f)

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MWs)[(d)]
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	8 (f)
Solar New Jersey 3	Middle Township, NJ	5	51 (g)	Solar	Intermittent	1 (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						10,495
ERCOT						
Whitetail	Webb County, TX	57	51 (g)	Wind	Intermittent	47 (f)
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

Station[(a)]	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MWs)[(d)]
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	15 (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	13	51 (g)	Wind	Intermittent	14 (f)
Wildcat	Lovington, NM	13	51 (g)	Wind	Intermittent	14 (f)
Echo 2	Echo, OR	9	51 (g)	Wind	Intermittent	9 (f)
Tuana Springs	Hagerman, ID	8	51 (g)	Wind	Intermittent	9 (f)
Greensburg	Greensburg, KS	10	51 (g)	Wind	Intermittent	6 (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	2 (f)
Mystic 8, 9	Charlestown, MA	6		Gas	Intermediate	1,413 (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	191
West Medway	West Medway, MA	3		Oil	Peaking	124
Grand Prairie	Alberta, Canada	1		Gas	Peaking	105
Framingham	Framingham, MA	3		Oil	Peaking	31
Total Other						3,265
Total						32,355

(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. Natural gas and oil 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 Units 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 Combined Notes to 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 22 — Variable Interest Entities of the Combined 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 also own EMT, which is a liquefied natural gas (LNG) import facility located on the Mystic River in Everett, MA. EMT connects to two interstate pipeline systems as well as a local gas utility's distribution system and the Mystic Generating Station.

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 on insurance specific to our nuclear facilities, see Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. 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 Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

PART II

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

CEG Parent

Our common stock is listed on the Nasdaq (trading symbol: CEG). As of January 31, 2023 there were 327,131,082 shares of common stock outstanding and approximately 75,145 record holders of common stock.

Stock Performance Graph

The performance graph below illustrates a one-year comparison of cumulative total returns based on an initial investment of $100 in CEG Parent common stock, as compared with the S&P 500 Stock Index and the Philadelphia Utility Sector Index, or UTY, for the year 2022.

This performance chart assumes:

- $100 invested on February 1, 2022, in CEG Parent common stock, the S&P 500 Stock Index, and the UTY, and
- All dividends are reinvested.

ceg-20221231_g9.jpg

Value of Investment in 2022		
	2/1	12/31
CEG	$100	$175
S&P 500	$100	$86
UTY	$100	$107

Constellation

As of January 31, 2023, CEG Parent directly held the entire membership interest in Constellation.

Dividends

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.

Our Board of Directors approved an updated dividend policy for 2023. The 2023 quarterly dividend will be $0.2820 per share.

The following table sets forth Constellation’s quarterly cash dividends per share paid during 2022.

Fourth Quarter	Third Quarter	Second Quarter	First Quarter
$ 0.1410	$ 0.1410	$ 0.1410	$ 0.1410

First Quarter 2023 Dividend

On February 15, 2023, our Board of Directors declared a regular quarterly dividend of $0.2820 per share on our common stock for the first quarter of 2023. The dividend is payable on Friday, March 10, 2023, to shareholders of record as of 5 p.m. Eastern time on Monday, February 27, 2023.

Unregistered Sales of Equity Securities

None.

Issuer Purchases of Equity Securities

None.

ITEM 6. RESERVED

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 primarily 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. The following Management's Discussion and Analysis of Financial Condition and Results of Operations summarizes results for the year ended December 31, 2022 compared to the year ended December 31, 2021. For discussion of the year ended December 31, 2021 compared to the year ended December 31, 2020, refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the 2021 Form 10-K, which was filed with the SEC on February 25, 2022.

Capital Allocation and Growth Announcements

We are announcing our capital allocation strategy for 2023 and 2024 supporting our core principles outlined in our Strategy and Outlook discussion. See ITEM 1. BUSINESS – Constellation's Strategy and Outlook for additional information about our strategy.

We will double the annual dividend in 2023 from $0.5640 per share to $1.1280 per share while targeting growth of 10% annually. We are allocating capital towards our best-in-class generation fleet by committing $1.5 billion of growth capital expenditures over the next three years, including nuclear uprates, wind repowering and hydrogen. These organic growth opportunities are projected to exceed our double-digit return threshold. In our commitment to return value to shareholders, we have also authorized a share buyback program of $1.0 billion.

Significant 2022 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 energy 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 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information.

We incurred separation costs of $140 million and $49 million for the twelve months ended December 31, 2022 and 2021, respectively, which are primarily recorded in Operating and maintenance expense. We expect to incur incremental costs of approximately $80 million in 2023. The separation costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation.

PJM Performance Bonuses

On December 23, 2022, and continuing through the morning of December 25, 2022, winter storm Elliott blanketed the entirety of PJM's footprint with record low temperatures and extreme weather conditions. A significant portion of PJM's fossil generation fleet failed to perform as reserves were called. PJM's initial estimate of non-performance charges ranges from $1 billion to $2 billion and, in accordance with its tariff, funds collected from those charges are redistributed to generating resources that performed above expectations during the event. PJM released preliminary invoices to generators subject to non-performance charges and bonuses on February 10, 2023. PJM indicated that these preliminary invoices are informational and subject to change for items that could have a material impact to the final amounts billed to non-performing generators, pending PJM's completion of their internal processes and data quality assurance reviews. Leveraging preliminary data from PJM and applying significant judgments and assumptions, we recognized an estimated benefit of $109 million (pre-tax) for performance bonuses (net of non-performance charges), primarily driven by the overperformance of our nuclear fleet. The ultimate impact to our consolidated financial statements may be affected by several factors, including final non-performance charges billed, the impacts of generator defaults, and related litigation and disputes. It is reasonably possible that the ultimate benefit could differ significantly once these uncertainties are resolved, which could have a material impact on our financial statements.

Other Key Business Drivers

Russia and Ukraine Conflict

We are closely monitoring developments of the Russia and Ukraine conflict including United States sanctions against Russian energy exports, the potential for sanctions on Russian nuclear fuel supply, and enrichment activities, as well as yet undefined action by Russia to limit energy deliveries. To-date, our nuclear fuel deliveries have not been affected by the Russia and Ukraine conflict. Our nuclear fuel is obtained predominantly through long-term uranium supply and service contracts. We work with a diverse set of domestic and international suppliers years in advance to procure our nuclear fuel and generally have enough nuclear fuel to support all our refueling needs for multiple years regardless of sanctions. Recognizing the potential for the continuing conflict to impact our longer-term security and cost of supply, we have entered into contracts to increase the size of our nuclear fuel inventory. We are taking this affirmative action by working with our diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term and provide the necessary fuel to bridge potential Russian supply disruption through 2028, which is the date multiple suppliers are expected to have incremental capacity online. We are also continuing to work with federal policymakers and other stakeholders to facilitate the expansion of the domestic nuclear fuel cycle within the United States to improve carbon-free energy security.

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 typically 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, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% and 75%-78% for 2023 and 2024, 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 60% of our uranium concentrate requirements from 2023 through 2027 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, including the Russia and Ukraine conflict and United States sanctions against Russia, have the potential to impact delivery from multiple suppliers in the international uranium processing 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 Combined 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 consolidated 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 Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations

The AROs associated with decommissioning our nuclear units were $12.5 billion at December 31, 2022. 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 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 Combined 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 decrease from approximately $12.5 billion to approximately $10.5 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	Increase (Decrease) to ARO as of December 31, 2022
2021 CARFR rather than the 2022 CARFR	$ 3,470
2022 CARFR increased by 50 basis points	(570)
2022 CARFR decreased by 50 basis points	710

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 (Decrease) to ARO as of December 31, 2022
Cost escalation studies		
Uniform increase in escalation rates of 50 basis points	$	1,780
Probabilistic cash flow models		
Increase the estimated costs to decommission the nuclear plants by 10 percent		720
Increase the likelihood of the DECON scenario by 10 percent and decrease the likelihood of the SAFSTOR scenario by 10 percent[(a)]		140
Shorten each unit's probability weighted operating life assumption by 10 percent[(b)]		280
Extend the estimated date for DOE acceptance of SNF to 2040		(70)

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

See Note 1 — Basis of Presentation and Note 10 — Asset Retirement Obligations of the Combined 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 Combined 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 (asset group) 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 Combined 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 Combined Notes to 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 — Basis of Presentation and Note 8 — Property, Plant, and Equipment of the Combined 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 Combined 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 NPNS requires judgment on whether the contract will physically deliver and requires that management ensure compliance with all associated qualification and documentation requirements. 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. Revenues and expenses on contracts that qualify as NPNS are recognized when the underlying physical transaction is completed.

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 commodities, 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 consolidated 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 Combined Notes to Consolidated Financial Statements for additional information regarding derivative instruments.

Defined Benefit Pension and Other Postretirement Employee Benefits

We sponsor defined benefit pension and OPEB plans for most current employees. The measurement of the plan obligations and costs of providing benefits involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. When developing the required assumptions, we consider historical information as well as future expectations. The measurement of projected benefit obligations and costs is affected by several assumptions including the discount rate, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, our contributions, the rate of compensation increases, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations.

Pension and OPEB plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity, private credit, and hedge funds.

Expected Rate of Return on Plan Assets. In determining the EROA, we consider expectations regarding future long-term capital market performance, weighted by our target asset class allocations. We calculate the amount of expected return on pension and OPEB plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, we use a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For OPEB plan assets and certain pension plan assets, we use fair value to calculate the MRV.

Discount Rate. The discount rates are determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and OPEB obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and OPEB plans. The discount rate is the single level rate that produces the same result as the spot rate curve. We utilize an analytical tool developed by our actuaries to determine the discount rates.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. At separation and upon remeasurement as of December 31, 2022, we utilized the mortality tables and projection scales released by the SOA.

Sensitivity to Changes in Key Assumptions. The following table illustrates the effects of changing certain of the actuarial assumptions reflected above and as discussed in Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements, while holding all other assumptions constant:

	Actual Assumption			Increase / (Decrease)		
Actuarial Assumption	Pension	OPEB	Assumption	Pension	OPEB	Total
Change in 2023 cost:						
Discount rate[a]	5.52 %	5.50 %	0.5 %	$ (13)	$ (1)	$ (14)
	5.52 %	5.50 %	(0.5) %	16	2	18
EROA	6.50 %	6.50 %	0.5 %	(40)	(4)	(44)
	6.50 %	6.50 %	(0.5) %	40	4	44
Change in benefit obligation:						
Discount rate[a]	5.52 %	5.50 %	0.5 %	(345)	(61)	(406)
	5.52 %	5.50 %	(0.5) %	391	69	460

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(a) In general, the discount rate will have a larger impact on the pension and OPEB cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, we utilize a liability-driven hedging investment strategy for our pension asset portfolio. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

See Note 1 — Basis of Presentation and Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension and OPEB plans.

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 Combined 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 Combined 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 — Basis of Presentation of the Combined 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.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth our GAAP consolidated Net Loss Attributable to Common Shareholders for the twelve months ended December 31, 2022 compared to the same period in 2021. For additional information regarding the financial results for the twelve months ended December 31, 2022 and 2021 see the discussions of Results of Operations below.

	Twelve Months Ended December 31,		
	2022	2021	Favorable Variance
GAAP Net Loss Attributable to Common Shareholders	$ (160)	$ (205)	$ 45

Adjusted EBITDA (non-GAAP). In analyzing and planning for our business, we supplement our use of GAAP Net Loss Attributable to Common Shareholders with Adjusted EBITDA (non-GAAP) as a performance measure. Adjusted EBITDA (non-GAAP) reflects an additional way of viewing our business that, when viewed with our GAAP results and the accompanying reconciliation to GAAP Net Loss Attributable to Common Shareholders included in the table below, may provide a more complete understanding of factors and trends affecting our business. Adjusted EBITDA (non-GAAP) should not be relied upon to the exclusion of GAAP financial measures and is, by definition, an incomplete understanding of our business, and must be considered in conjunction with GAAP measures. In addition, Adjusted EBITDA (non-GAAP) is neither a standardized financial measure, nor 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.

The following table provides a reconciliation between Net loss attributable to common shareholders as determined in accordance with GAAP and Adjusted EBITDA (non-GAAP) for the twelve months ended December 31, 2022 compared to the same period in 2021.

	Twelve Months Ended December 31, 2022	Twelve Months Ended December 31, 2021
Net Loss Attributable to Common Shareholders	$ (160)	$ (205)
Income Taxes[(a)]	(339)	225
Depreciation and Amortization[(b)]	1,091	3,003
Interest Expense, Net	251	297
Unrealized Loss (Gain) on Fair Value Adjustments[(c)]	1,058	(420)
Asset Impairments[(d)]	—	541
Plant Retirements and Divestitures	(11)	(4)
Decommissioning-Related Activities[(e)]	820	(1,289)
Pension & OPEB Non-Service Credits	(116)	(50)
Separation Costs[(f)]	140	49
COVID-19 Direct Costs[(g)]	—	35
Acquisition-Related Costs[(h)]	—	21
ERP System Implementation Costs[(i)]	22	14
Change in Environmental Liabilities	10	12
Cost Management Program	—	9
Prior Merger Commitment[(j)]	(50)	—
Noncontrolling Interests[(k)]	(49)	(53)
Adjusted EBITDA (non-GAAP)	$ 2,667	$ 2,185

(a) In 2022, includes amounts contractually owed to Exelon under the Tax Matters Agreement (TMA) reflected in Other, net.
(b) In 2021, includes the accelerated depreciation associated with early plant retirements.
(c) Includes mark-to-market on economic hedges and fair value adjustments related to gas imbalances and equity investments.
(d) Reflects an impairment in the New England asset group, an impairment recorded as a result of the sale of the Albany Green Energy biomass facility, and impairment of a wind project.
(e) Reflects all gains and losses associated with NDTs, ARO accretion, ARO remeasurement, and any earnings neutral impacts of contractual offset for Regulatory Agreement Units.
(f) Represents certain incremental costs related to the separation (system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation), including a portion of the amounts billed to us pursuant to the Transition Services Agreement (TSA).
(g) Represents direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees.
(h) Reflects costs related to the acquisition of EDF's interest in CENG, which was completed in the third quarter of 2021.
(i) Reflects costs related to a multi-year ERP system implementation.
(j) Reversal of a charge related to a prior 2012 merger commitment.
(k) Reflects elimination from results for the noncontrolling interests related to certain adjustments. In 2022, primarily relates to CRP and in 2021, primarily relates to CENG and the noncontrolling interest portion of a wind project impairment recognized within CRP.

Results of Operations

	2022	2021	Favorable (Unfavorable) Variance
Operating revenues	$ 24,440	$ 19,649	$ 4,791
Operating expenses			
Purchased power and fuel	17,462	12,163	(5,299)
Operating and maintenance	4,841	4,555	(286)
Depreciation and amortization	1,091	3,003	1,912
Taxes other than income taxes	552	475	(77)
Total operating expenses	23,946	20,196	(3,750)
Gain on sales of assets and businesses	1	201	(200)
Operating income (loss)	495	(346)	841
Other income and (deductions)			
Interest expense, net	(251)	(297)	46
Other, net	(786)	795	(1,581)
Total other income and (deductions)	(1,037)	498	(1,535)
(Loss) income before income taxes	(542)	152	(694)
Income taxes	(388)	225	613
Equity in losses of unconsolidated affiliates	(13)	(10)	(3)
Net loss	(167)	(83)	(84)
Net (loss) income attributable to noncontrolling interests	(7)	122	(129)
Net loss attributable to common shareholders	$ (160)	$ (205)	$ 45

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021. Net loss attributable to common shareholders was favorable by $45 million primarily due to:

- The absence of 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 the absence of the reversal of charges recorded in the third quarter of 2021 associated with the reversal of the previous decision;
- The absence of impacts from the February 2021 extreme cold weather event;
- The absence of impairments of the New England asset group, the Albany Green Energy biomass facility, and a wind project;
- Impact of our annual update to the nuclear ARO for Non-Regulatory Agreement Units;
- Lower nuclear fuel costs primarily due to the absence of accelerated amortization of nuclear fuel and lower prices;
- Higher realized energy prices;
- Favorable PJM performance bonus payment, net of non-performance charges;
- The reversal of a charge related to a 2012 prior merger commitment; and
- Favorable impacts of nuclear outages.

The favorable items were partially offset by:

- Unfavorable mark-to-market activity;
- Unfavorable net realized and unrealized NDT activity;

- Lower capacity revenues;
- Higher labor, contracting and materials;
- Unfavorable impact of net realized and unrealized CTV investment activity;
- Higher separation costs;
- Lower NEIL distributions; and
- The absence of a prior year gain on the sale of our solar business.

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 Combined 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: wholesale and retail sales of natural gas, as well as other miscellaneous business activities that are not significant to overall results of operations.

For the year ended December 31, 2022 compared to 2021, Operating revenues by region were as follows:

			2022 vs. 2021	
	2022	2021	Variance	% Change[a]
Mid-Atlantic	$ 5,164	$ 4,584	$ 580	12.7 %
Midwest	4,650	4,060	590	14.5 %
New York	1,595	1,575	20	1.3 %
ERCOT	1,543	1,181	362	30.7 %
Other Power Regions	6,732	4,890	1,842	37.7 %
Total electric revenues	19,684	16,290	3,394	20.8 %
Other	5,944	3,992	1,952	48.9 %
Mark-to-market losses	(1,188)	(633)	(555)	
Total Operating revenues	$ 24,440	$ 19,649	$ 4,791	24.4 %

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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:

Supply Source (GWhs)	2022	2021	2022 vs. 2021 Variance	2022 vs. 2021 % Change
Nuclear Generation[a]				
Mid-Atlantic	53,214	53,589	(375)	(0.7)%
Midwest	95,090	93,107	1,983	2.1 %
New York[b]	25,046	26,294	(1,248)	(4.7)%
Total Nuclear Generation	173,350	172,990	360	0.2 %
Natural Gas, Oil and Renewables				
Mid-Atlantic	2,097	2,271	(174)	(7.7)%
Midwest	1,202	1,083	119	11.0 %
New York	—	1	(1)	(100.0)%
ERCOT	14,124	13,187	937	7.1 %
Other Power Regions	10,189	9,995	194	1.9 %
Total Natural Gas, Oil and Renewables	27,612	26,537	1,075	4.1 %
Purchased Power				
Mid-Atlantic	15,366	13,576	1,790	13.2 %
Midwest	610	561	49	8.7 %
ERCOT	3,575	3,256	319	9.8 %
Other Power Regions	51,131	50,212	919	1.8 %
Total Purchased Power	70,682	67,605	3,077	4.6 %
Total Supply/Sales by Region				
Mid-Atlantic	70,677	69,436	1,241	1.8 %
Midwest	96,902	94,751	2,151	2.3 %
New York[b]	25,046	26,295	(1,249)	(4.7)%
ERCOT	17,699	16,443	1,256	7.6 %
Other Power Regions	61,320	60,207	1,113	1.8 %
Total Supply/Sales by Region	271,644	267,132	4,512	1.7 %

(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 Combined Notes to Consolidated Financial Statements for additional information on our acquisition of EDF's interest in CENG.
(b) 2021 values have been revised from those previously reported to correctly reflect our 82% undivided ownership interest in Nine Mile Point Unit 2.

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 its net monthly 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.

	2022	2021
Nuclear fleet capacity factor	94.8 %	94.5 %
Refueling outage days	212	262
Non-refueling outage days	54	34

ZEC Prices. We are compensated through state programs for the carbon-free attributes of our nuclear generation. ZEC programs are a significant contributor to our total operating revenues. The following table includes the average ZEC reference 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 the years ended December 31, 2022 and 2021.

State (Region)[(a)]	2022	2021	2022 vs. 2021 Variance	2022 vs. 2021 % Change
New Jersey (Mid-Atlantic)	$ 10.00	$ 10.00	$ —	— %
Illinois (Midwest)	13.88	16.50	(2.62)	(15.9)%
New York (New York)	21.38	20.93	0.45	2.2 %

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

Illinois CMC Price. The price received (paid) for each CMC is determined by the IPA monthly and is based on the accepted CMC bid, less the sum of (a) monthly weighted average PJM Busbar price, (b) ComEd zone capacity price and (c) any federal tax credit or subsidy received and is subject to a customer protection cap ($30.30 per MWh for initial delivery period June 1, 2022 through May 31, 2023). If the monthly CMC price per MWh calculation results in a net positive value, ComEd will multiply that value by the delivered quantity and pay the total to us. If the CMC price per MWh calculation results in a net negative value, we will multiply this value by the delivered quantity and pay the net value to ComEd. For the year ended December 31, 2022 the average CMC price per MWh was a net negative value ($42.20). See Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois CMC program.

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, which are factored into customer sales prices. Capacity prices have a significant impact on our operating revenues and purchased power and fuel expense. We report capacity on a net monthly basis within each region in either Operating revenues or Purchased power and fuel expense, depending on our net monthly position. 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 the years ended December 31, 2022 and 2021.

Location (Region)	2022	2021	2022 vs. 2021 Variance	2022 vs. 2021 % Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic and Midwest)	$ 126.14	$ 174.96	$ (48.82)	(27.9)%
ComEd (Midwest)	121.71	192.45	(70.74)	(36.8)%
Rest of State (New York)	85.36	98.35	(12.99)	(13.2)%
Southeast New England (Other)	138.21	163.66	(25.45)	(15.6)%

Electricity Prices. As a producer and supplier of electricity, the price of electricity has a significant impact on our operating revenues and purchased power cost. We report the sale and purchase of electricity in the spot market on a net hourly basis in either Operating revenues or Purchased power and fuel expense within each region, depending on our net hourly position. The price of electricity is impacted by several variables, including but not limited to, the price of fuels, generation resources in the region, weather, on-going competition, emerging technologies, as well as macroeconomic and regulatory factors.The following table presents an average day-ahead around-the-clock reference price ($/MWh) for the periods presented for each of our major regions and does not necessarily reflect prices we ultimately realized.

Location (Region)	2022	2021	2022 vs. 2021 Variance	2022 vs. 2021 % Change
PJM West (Mid-Atlantic)	$ 72.90	$ 38.91	$ 33.99	87.4 %
ComEd (Midwest)	60.24	34.76	25.48	73.3 %
Central (New York)	57.52	29.90	27.62	92.4 %
North (ERCOT)	64.38	146.63	(82.25)	(56.1)%
Southeast Massachusetts (Other)[(a)]	86.02	46.38	39.64	85.5 %

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

For the year ended December 31, 2022 compared to 2021, changes in **Operating revenues** by region were approximately as follows:

	2022 vs. 2021 Variance	2022 vs. 2021 % Change[(a)]	Description
Mid-Atlantic	$ 580	12.7 %	• favorable retail load revenue of $525 primarily due to higher energy prices • favorable wholesale load revenue of $360 primarily due to higher volumes and energy prices; partially offset by • unfavorable settled economic hedges of ($280) due to settled prices relative to hedged prices
Midwest	590	14.5 %	• favorable net wholesale load and generation revenue of $630 primarily due to higher nuclear generation and energy prices, partially offset by CMC program activity and the absence of net capacity revenue • favorable retail load revenue of $275 primarily due to higher energy prices • favorable PJM performance bonuses of $116 due to generation performance against capacity requirements during December 2022 weather event; partially offset by • unfavorable settled economic hedges of ($430) due to settled prices relative to hedged prices
New York	20	1.3 %	• favorable retail load revenue of $295 primarily due to higher energy prices • favorable generation revenue of $150 due to higher energy prices, partially offset by lower nuclear generation due to an increase in outage days; partially offset by • unfavorable settled economic hedges of ($410) due to settled prices relative to hedged prices
ERCOT	362	30.7 %	• favorable settled economic hedges of $340 due to settled prices relative to hedged prices • favorable retail load revenue of $115 primarily due to higher volumes partially offset by lower energy prices relative to the prior year due to the February 2021 extreme cold weather event; partially offset by • unfavorable wholesale load revenue of ($70) primarily due to lower energy prices relative to the prior year due to the February 2021 extreme cold weather event
Other Power Regions	1,842	37.7 %	• favorable wholesale load revenue of $820 due to higher energy prices and volumes • favorable settled economic hedges of $540 due to settled prices relative to hedged prices • favorable retail load revenue of $430 due to higher energy prices and volumes

Other	1,952	48.9 %	• favorable gas revenue, including settled financial hedges, of $1,655 primarily due to higher gas prices • favorable energy revenue of $370 primarily due to higher energy prices; partially offset by • unfavorable impact due to the absence of the customer pass through impact of LDC and pipeline penalties due to the February 2021 extreme cold weather event of ($70)
Mark-to-market[(b)]	(555)		• losses on economic hedging activities of ($1,188) in 2022 compared to losses of ($633) in 2021
Total	$ 4,791	24.4 %	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 16 — Derivative Financial Instruments of the Combined 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: wholesale and retail sales of 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, 2022 compared to 2021, Purchased power and fuel expense by region were as follows:

			2022 vs. 2021	
	2022	2021	Variance	% Change[(a)]
Mid-Atlantic	$ 3,026	$ 2,320	$ (706)	(30.4) %
Midwest	1,886	1,343	(543)	(40.4) %
New York	528	414	(114)	(27.5) %
ERCOT	1,136	2,006	870	43.4 %
Other Power Regions	5,811	3,999	(1,812)	(45.3) %
Total electric purchased power and fuel	12,387	10,082	(2,305)	(22.9) %
Other	5,250	3,279	(1,971)	(60.1) %
Mark-to-market gains	(175)	(1,198)	(1,023)	
Total purchased power and fuel	$ 17,462	$ 12,163	$ (5,299)	(43.6) %

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

For the year ended December 31, 2022 compared to 2021, changes in **Purchased power and fuel** expense by region were approximately as follows:

	2022 vs. 2021		
	Variance	% Change[(a)]	Description
Mid-Atlantic	$ (706)	(30.4)%	• unfavorable purchased power and net capacity impact of ($660) primarily due to higher energy prices, higher load, and lower capacity prices earned • unfavorable PJM net non-performance charges of ($7) due to generation performance against capacity requirements during December 2022 weather event
Midwest	(543)	(40.4)%	• unfavorable purchased power and net capacity impact of ($590) primarily due to higher energy prices, lower capacity prices earned, and lower cleared capacity volumes; partially offset by • favorable nuclear fuel cost of $65 primarily due to the absence of accelerated amortization of nuclear fuel and lower nuclear fuel prices in the prior year
New York	(114)	(27.5)%	• unfavorable purchased power and net capacity impact of ($190) primarily due to higher energy prices, lower nuclear generation and lower capacity prices earned; partially offset by • favorable settlement of economic hedges of $90 due to settled prices relative to hedged prices
ERCOT	870	43.4 %	• favorable purchased power of $635 primarily due to lower energy prices relative to the prior year due to the February 2021 extreme cold weather event • favorable settlement of economic hedges of $140 due to settled prices relative to hedged prices • favorable fuel cost of $80 primarily due to lower gas prices relative to the prior year due to the February 2021 extreme cold weather event
Other Power Regions	(1,812)	(45.3)%	• unfavorable purchased power and net capacity impact of ($2,180) primarily due to higher energy prices, higher load, lower cleared capacity volumes and lower capacity prices earned • unfavorable fuel cost of ($400) primarily due to higher gas prices • unfavorable environmental products activity of ($415) primarily driven by lower optimization and higher RPS costs; partially offset by • favorable settlement of economic hedges of $1,210 due to settled prices relative to hedged prices
Other	(1,971)	(60.1)%	• unfavorable net gas purchase costs and settlement of economic hedges of ($1,885) • unfavorable energy purchases of ($290) primarily due to higher energy prices • unfavorable fair value adjustment related to gas imbalances of ($50); partially offset by • favorable impact due to the absence of LDC and pipeline penalties due to the February 2021 extreme cold weather event of $110 • favorable impact due to the absence of accelerated nuclear fuel amortization associated with announced early plant retirements of $150

Mark-to-market[b]	(1,023)		• gains on economic hedging activities of $175 in 2022 compared to gains of $1,198 in 2021
Total	$ (5,299)	(43.6)%	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 16 — Derivative Financial Instruments of the Combined 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:

	2022 vs. 2021 Increase (Decrease)
Labor, other benefits, contracting, and materials[a]	$ 317
Decommissioning-related activities[b]	298
NEIL insurance distributions	83
Plant retirements and divestitures[c]	78
Separation costs[d]	74
Loss on sale of receivables	33
Nuclear refueling outage costs, including the co-owned Salem plants	32
Credit loss expense[e]	(23)
Covid-19 direct costs	(35)
Prior merger commitment[f]	(50)
Asset impairments	(541)
Other	20
Total increase	$ 286

(a) Primarily reflects increased employee-related costs, including labor, stock-based compensation, and other incentives, etc.
(b) 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 Combined Notes to Consolidated Financial Statements for additional information.
(c) Reflects the absence of the reversal of charges recorded in 2021 associated with the reversal of the previous decision to early retire Byron and Dresden.
(d) Represents certain incremental costs related to the separation (system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation), including a portion of the amounts billed to us pursuant to the TSA.
(e) Primarily a result of the February 2021 extreme cold weather event.
(f) Reversal of a charge related to a prior merger commitment.

Depreciation and amortization expense decreased for the year ended December 31, 2022 compared to the same period in 2021, 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 decreased for the year ended December 31, 2022 compared to the same period in 2021, primarily due to gains on sales of equity investments and a gain on sale of our solar business which were recognized in 2021.

Interest expense, net decreased for the year ended December 31, 2022 compared to the same period in 2021, primarily due to mark-to-market gains related to our CR and West Medway II interest rate swaps and the retirement of long-term debt in March 2022. See Note 17 — Debt and Credit Agreements of the Combined 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, 2022 compared to the same period in 2021, due to activity described in the table below:

	2022	2021
Net unrealized (losses) gains on NDT funds[(a)]	$ (798)	$ 204
Net realized gains on sale of NDT funds[(a)]	4	381
Interest and dividend income on NDT funds[(a)]	93	98
Contractual elimination of income tax (expense) benefit[(b)]	(201)	226
Non-service net periodic benefit credit[(c)]	110	—
Net realized and unrealized losses from equity investments[(d)]	(13)	(160)
Return to provision adjustment[(e)]	(49)	—
TSA billings[(f)]	44	—
Other	24	46
Total Other, net	$ (786)	$ 795

(a) Unrealized gains, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.
(b) Contractual elimination of income tax (expense) benefit is associated with the income taxes on the NDT funds of the Regulatory Agreement Units.
(c) Historically, we were allocated our portion of pension and OPEB non-service credit (cost) from Exelon, which was included in Operating and maintenance expense. Effective February 1, 2022, the non-service credit (cost) components are included in Other, net, in accordance with single employer plan accounting. See Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.
(d) For 2022, includes net realized and unrealized (losses) gains from equity investments. For 2021, includes net unrealized (losses) gains from equity investments.
(e) Reflects amounts contractually owed to Exelon under the TMA, which is offset in Income taxes. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
(f) Amounts we billed Exelon for services pursuant to the TSA. See Note 1 - Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information.

Effective income tax rates were 71.6% and 148% for the years ended December 31, 2022 and 2021, respectively. The change in effective tax rate in 2022 is primarily due to the impacts of higher unrealized NDT losses on Income before income taxes and one-time income tax adjustments. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Net (loss) income attributable to noncontrolling interests primarily relates to CRP for the year ended December 31, 2022 and includes CENG and CRP for the same period in 2021. The decrease for the year ended December 31, 2022 for the same period in 2021 is primarily due to our acquisition of EDF's interest in CENG on August 6, 2021. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Liquidity and Capital Resources

For discussion of the year ended December 31, 2021 compared to the year ended December 31, 2020, refer to Liquidity and Capital Resources of MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the 2021 Form 10-K which was filed with the SEC on February 25, 2022.

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 $5.8 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 and Cash Requirements” 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 Combined 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 1 — Basis of Presentation of the Combined 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 Combined Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to retire before the end of its licensed life, 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 additional financial assurance mechanisms to address a decommissioning funding shortfall, 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, 2022, 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. On June 8, 2022, the NRC granted our exemption request to use the TMI Unit 1 NDT funds for site restoration costs.

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 Combined 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, 2022 and 2021:

(Decrease) increase in cash flows from operating activities	For the Years Ended December 31, 2022	2021	Change
Net loss	$ (167)	$ (83)	$ (84)
Adjustments to reconcile net loss to cash:			
Changes in working capital and other noncurrent assets and liabilities[(a)]	(5,246)	(3,608)	(1,638)
Collateral posted, net	(351)	(130)	(221)
Pension and non-pension postretirement benefit contributions	(237)	(259)	22
Option premiums paid, net	(177)	(338)	161
Total non-cash operating activities[(b)]	3,825	3,080	745
Decrease in cash flows from operating activities	$ (2,353)	$ (1,338)	$ (1,015)

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(a) Includes changes in Accounts receivable, Receivables from and payables to affiliates, Inventories, Accounts payable and accrued expenses, Income taxes, and Other assets and liabilities.
(b) See the Consolidated Statements of Cash Flows for details of non-cash operating activities, includes Depreciation, amortization, and accretion, Asset impairments, Gain on sales of assets and businesses, Deferred income taxes and amortization of ITCs, Net fair value changes related to derivatives, and Net realized and unrealized activity associated with NDTs and equity investments. See Note 23 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information on the Other non-cash operating activities line.

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 2022 and 2021 were as follows:

- A reduction in cash inflows for **changes in working capital and other noncurrent assets and liabilities** primarily driven by activity related to the accounts receivable Facility, due to higher retail power sales and associated accounts receivables sold relative to the maximum funding limit of the Facility, partially offset by an increase in cash inflows from the Collection of DPP, net in Cash Flows from investing activities, which can be seen in the Cash Flows from Investing Activities section below. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the sales of customer accounts receivables.
- 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 Combined Notes to Consolidated Financial Statements for additional information on collateral.
- **Option premiums paid, net** 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. Note 16 — Derivative Financial Instruments of the Notes to Consolidated Financial Statements for additional information on derivative contracts.

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, 2022 and 2021:

(Decrease) increase in cash flows from investing activities	For the Years Ended December 31, 2022	2021	Change
Proceeds from sales of assets and businesses	$ 52	$ 878	$ (826)
Capital expenditures	(1,689)	(1,329)	(360)
Investment in NDT funds, net	(221)	(141)	(80)
Collection of DPP, net	4,964	3,902	1,062
Other investing activities	(2)	(28)	26
Decrease in cash flows from investing activities	$ 3,104	$ 3,282	$ (178)

Significant investing cash flow impacts for 2022 and 2021 were as follows:

- **Proceeds from sales of assets and businesses** decreased primarily due to the sale of a significant portion of our solar business, sale of a biomass facility and proceeds received on sales of equity investments in 2021. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the sale of our solar business and biomass facility.
- 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.
- **Collection of DPP, net** increased due to cash collections from the accounts receivable Facility, as discussed in the Cash Flows from Operating Activities section above. This was partially offset by a reduction in cash proceeds received from the Purchasers in 2022 compared to 2021. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

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, 2022 and 2021:

Increase (decrease) in cash flows from financing activities	For the Years Ended December 31, 2022	2021	Change
Distributions to Exelon	$ —	$ (1,832)	$ 1,832
Contributions from Exelon	1,750	64	1,686
Acquisition of CENG noncontrolling interest	—	(885)	885
Change in money pool with Exelon	—	(285)	285
Dividends paid on common stock	(185)	—	(185)
Long-term debt, net	(1,406)	47	(1,453)
Changes in short-term borrowings, net	(923)	1,242	(2,165)
Other financing activities	(35)	(46)	11
Increase in cash flows from financing activities	$ (799)	$ (1,695)	$ 896

Significant financing cash flow impacts for 2022 and 2021 were as follows:

- **Distributions to Exelon** is related to distributions made prior to separation. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information on the separation.

- **Contributions from Exelon** is primarily related to a cash contribution of $1.75 billion from Exelon on January 31, 2022, pursuant to the Separation Agreement. See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information on the separation.
- See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information related to the **acquisition** of CENG noncontrolling interest.
- **Change in money pool with Exelon** were driven by short-term borrowing needs prior to the separation on February 1, 2022. 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.
- Refer to ITEM 5. — MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES for additional information on dividend restrictions. See below for quarterly **dividends** declared.
- **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 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 Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings.

Debt Issuances and Redemptions

See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our long-term debt. Debt activity for 2022 and 2021 was as follows:

During 2022, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
Energy Efficiency Project Financing[a]	2.20% - 6.96%	March 31, 2023 - May 1, 2024	$ 14	Funding to install energy conservation measures.

(a) 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 issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
West Medway II Nonrecourse Debt[a]	1 month 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 Combined Notes to Consolidated Financial Statements for additional information of 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 2022, the following long-term debt was retired and/or redeemed:

Type	Interest Rate	Maturity	Amount
Senior Notes	3.40%	March 15, 2022	$ 500
Senior Notes	4.25%	June 15, 2022	523
CR Nonrecourse Debt[a]	3 month LIBOR + 2.50%	December 15, 2027	41
Continental Wind Nonrecourse Debt[a]	6.00%	February 28, 2033	37
West Medway II Nonrecourse Debt[a]	1 month LIBOR + 2.875%[c]	March 31, 2026	24
Antelope Valley DOE Nonrecourse Debt[a][b]	2.29% - 3.56%	January 5, 2037	25
RPG Nonrecourse Debt[a]	4.11%	March 31, 2035	9
Energy Efficiency Project Financing	3.71%	December 31, 2022	3

(a) See Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt.
(b) On January 6, 2023, we redeemed $5 million of 2.29% - 3.56% Antelope Valley DOE nonrecourse debt.
(c) The nonrecourse debt has an average blended interest rate.

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 Combined Notes to Consolidated Financial Statements for additional information on the mirror debt.
(b) See Note 17 — Debt and Credit Agreements of the Combined 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.

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.

Dividends

Quarterly dividends declared by our Board of Directors during the twelve months ended December 31, 2022 and for the first quarter of 2023 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter of 2022	February 8, 2022	February 25, 2022	March 10, 2022	$ 0.1410
Second Quarter of 2022	April 26, 2022	May 13, 2022	June 10, 2022	$ 0.1410
Third Quarter of 2022	July 26, 2022	August 15, 2022	September 9, 2022	$ 0.1410
Fourth Quarter of 2022	October 31, 2022	November 15, 2022	December 9, 2022	$ 0.1410
First Quarter of 2023	February 15, 2023	February 27, 2023	March 10, 2023	$ 0.2820

Credit Matters and Cash Requirements

We fund liquidity needs for capital expenditures, working capital, energy hedging and other financial commitments through cash flows from operations, public debt offerings, commercial paper markets and large, diversified credit facilities. As of December 31, 2022, we have access to facilities with aggregate bank commitments of $5.8 billion. We had access to the commercial paper markets and had availability under our revolving credit facilities during 2022 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 had lost our investment grade credit rating as of December 31, 2022, we would have been required to provide incremental collateral estimated to be approximately $3.3 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. A loss of investment grade credit rating would have required a significant reduction in credit ratings from their current levels of BBB and Baa2 at S&P and Moody's, respectively, to BB+ and Ba1 or below. As of December 31, 2022, we had $2.2 billion of available capacity and $0.4 billion of cash on hand. In the event of a credit downgrade below investment grade and a resulting requirement to provide incremental collateral exceeding our available capacity and cash on hand, we would be required to access additional liquidity through the capital markets. See Note 16 — Derivative Financial Instruments and Note 17 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Capital Expenditures

Our most recent estimate of capital expenditures is approximately $2.6 billion for 2023 and approximately $5.0 billion for the period from 2024 to 2025. Approximately 45-47% of projected capital expenditures are for the acquisition of nuclear fuel, which includes additional nuclear fuel to increase inventory levels. This is a strategic decision in response to the potential for the continuing Russia and Ukraine conflict to impact our long-term nuclear fuel supply. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Other Key Business Drivers for more information on the Russia and Ukraine conflict.

Additionally, the above estimate of capital expenditures includes $1.5 billion of growth capital expenditures, including nuclear uprates, wind repowering, and hydrogen. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Executive Overview for additional information.

The remaining amounts primarily reflect additions and upgrades to existing generation facilities (including material condition improvements during nuclear refueling outages).

Planned additions and upgrades and other investments are subject to periodic review and revision to reflect changes in economic conditions impacting our generating assets and other factors, including, but not limited to, market power prices, results of capacity auctions, potential legislative and regulatory solutions, impacts of inflation, changes in the cost of materials and labor, and financing costs.

We anticipate funding these capital expenditures with a combination of internally generated funds and borrowings.

Pension and Other Postretirement Benefits

We consider 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, and management of the pension obligation. The Pension Protection 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 contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status over time. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, our non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

OPEB plans are also not subject to statutory minimum contribution requirements, though we have funded certain of our plans. For our funded OPEB plans, we consider several factors in determining the level of contributions including liabilities management and levels of benefit claims paid.

The following table provides our planned contributions to our qualified pension plans, non-qualified pension plans, and OPEB plans in 2023 (including our benefit payments related to unfunded plans):

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Planned contributions	$ 21	$ 10	$ 17

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if we change our pension or OPEB funding strategy. See Note 15 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on pension and OPEB contributions.

Cash Requirements for Other Financial Commitments

The following table summarizes our future estimated cash payments as of December 31, 2022 under existing financial commitments:

	2023	Beyond 2023	Total	Time Period
Long-term debt	$ 143	$ 4,507	$ 4,650	2023 - 2042
Interest payments on long-term debt[(a)]	225	2,448	2,673	2023 - 2042
Operating leases[(b)]	54	502	556	2023 - 2066
Purchase power obligations[(c)]	825	964	1,789	2023 - 2033
Fuel purchase agreements[(d)]	1,288	6,457	7,745	2023 - 2036
Other purchase obligations[(e)]	1,289	1,815	3,104	2023 - 2046
SNF obligation	—	1,230	1,230	2023 - 2035
Pension contributions[(f)]	21	183	204	2023 - 2028
Total cash requirements	$ 3,845	$ 18,106	$ 21,951	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2022 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, 2022.
(b) Capacity payments associated with contracted generation lease agreements are net of sublease and capacity offsets of $47 million and $322 million for 2023 and beyond 2023, respectively and $369 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, 2022 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 2028 are not included.

See Note 19 — Commitments and Contingencies and Note 3 — Regulatory Matters of the Combined 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 Combined Notes to Consolidated Financial Statements.

Item	Location within Combined Notes to 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
Pension contributions	Note 15 — Retirement Benefits

Sales of Customer Accounts Receivable

We have an accounts receivable financing facility with a number of financial institutions and a commercial paper conduit to sell certain receivables, which expires on August 15, 2025 unless renewed by the mutual consent of the parties in accordance with its terms. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

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 Combined 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 Combined Notes to Consolidated Financial Statements for additional information on our credit facilities.

Capital Structure

At December 31, 2022, our capital structure consisted of the following:

	Percentage of Capital Structure
Commercial paper and notes payable	7 %
Long-term debt	27 %
Member's equity	66 %

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 Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

At separation, S&P and Moody's affirmed our senior unsecured ratings of BBB- and Baa2, respectively. Fitch also affirmed their final rating of BBB, prior to formally withdrawing coverage on January 5th, 2022. We have only engaged S&P and Moody's for ratings coverage following separation. On October 13, 2022, S&P raised our senior unsecured debt rating to 'BBB' from 'BBB-' citing the passage of the IRA as a material credit positive for us.

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. After the separation on February 1, 2022, reporting on risk management issues is 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 produce or procure 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, natural gas and oil, 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 2023 through 2025.

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 generation sales not already hedged via comprehensive state programs, such as the CMC in Illinois, we typically utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant sales 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, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% and 75%-78% for 2023 and 2024, 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, 2022 market conditions and hedged position would be a decrease in pre-tax net income of approximately $8 million and $215 million for 2023 and 2024, 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 Combined 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, including contracts sourced from Russia, 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. We engage a diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term. Approximately 60% of our uranium concentrate requirements from 2023 through 2027 are supplied by three suppliers. To-date, we have not experienced any counterparty credit risk associated with these suppliers stemming from the Russian and Ukraine conflict. 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 Russia and 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 consolidated financial statements. To-date, we have not experienced any delivery or non-performance issues from our suppliers, nor any degradation in the quality of fuel we have received, and we are closely monitoring developments from the conflict. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Other Key Business Drivers for more information on the Russia and Ukraine conflict.

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, 2020 to December 31, 2022. 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 Combined 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, 2022 and 2021.

	Mark-to-Market Energy Contract Net Assets
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)
Total change in fair value during 2022 of contracts recorded in result of operations	(647)
Reclassification to realized at settlement of contracts recorded in results of operations	(380)
Changes in allocated collateral	386
Net option premium paid	177
Option premium amortization	(293)
Upfront payments and amortizations[b]	167
Foreign Currency Translation	14
Balance as of December 31, 2022	$ 1,046 (a)

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(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 Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

	Maturities Within						
	2023	2024	2025	2026	2027	2028 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$ 264	$ 169	$ 128	$ 68	$ 33	$ —	$ 662
Prices provided by external sources (Level 2)	238	4	(83)	6	—	—	165
Prices based on model or other valuation methods (Level 3)	284	(107)	83	38	7	(86)	219
Total	$ 786	$ 66	$ 128	$ 112	$ 40	$ (86)	$ 1,046

(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 $898 million at December 31, 2022.

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 Combined 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, 2022. 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, 2022	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	$ 1,304	$ 135	$ 1,169	—	$ —
Non-investment grade	110	88	22	—	—
No external ratings					
Internally rated—investment grade	106	—	106	—	—
Internally rated—non-investment grade	374	40	334	—	—
Total	$ 1,894	$ 263	$ 1,631	—	$ —

(a) As of December 31, 2022, credit collateral held from counterparties where we had credit exposure included $152 million of cash and $111 million of letters of credit.

Rating as of December 31, 2022	Maturity of Credit Risk Exposure Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,276	$ 7	$ 21	$ 1,304
Non-investment grade	108	2	—	110
No external ratings				
Internally rated—investment grade	106	—	—	106
Internally rated—non-investment grade	227	104	43	374
Total	$ 1,717	$ 113	$ 64	$ 1,894

Net Credit Exposure by Type of Counterparty	As of December 31, 2022
Investor-owned utilities, marketers, power producers	$ 1,311
Energy cooperatives and municipalities	112
Financial Institutions	9
Other	199
Total	$ 1,631

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 Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements and Note 19 — Commitments and Contingencies of the Combined 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 consolidated 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 and Cash Requirements — 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 consolidated financial statements. See Note 3 — Regulatory Matters of the Combined 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 not result in a material decrease in our pre-tax income for the year ended December 31, 2022. 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 Combined 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 $759 million reduction in the fair value of the trust assets as of December 31, 2022. 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

The management of Constellation Energy Corporation (CEG Parent) is 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.

CEG Parent's management assessed the effectiveness of CEG Parent's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, CEG Parent's management concluded that, as of December 31, 2022, CEG Parent's internal control over financial reporting was effective.

The effectiveness of CEG Parent's internal control over financial reporting as of December 31, 2022, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 16, 2023

Management's Report on Internal Control Over Financial Reporting

The management of Constellation Energy Generation, LLC (Constellation) is 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.

Constellation's management assessed the effectiveness of Constellation's internal control over financial reporting as of December 31, 2022. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Constellation's management concluded that, as of December 31, 2022, Constellation's internal control over financial reporting was effective.

February 16, 2023

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Constellation Energy Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(1)(ii), of Constellation Energy Corporation and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting 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 in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Nuclear Decommissioning Asset Retirement Obligations (ARO) Assessment

As described in Notes 1 and 10 to the consolidated financial statements, the Company has a legal obligation to decommission its nuclear power plants following the permanent cessation of operations. To estimate its decommissioning obligations 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 ARO 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, 2022, the nuclear decommissioning ARO was $12.5 billion.

The principal considerations for our determination that performing procedures relating to the Company's nuclear decommissioning ARO 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 discounted cash flow model used in management's ARO 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.

/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland
February 16, 2023

We have served as the Company's auditor since 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)(2)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(2)(ii), of Constellation Energy Generation, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022 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 matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Nuclear Decommissioning Asset Retirement Obligations (ARO) Assessment

As described in Notes 1 and 10 to the consolidated financial statements, the Company has a legal obligation to decommission its nuclear power plants following the permanent cessation of operations. To estimate its decommissioning obligations 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 ARO 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, 2022, the nuclear decommissioning ARO was $12.5 billion.

The principal considerations for our determination that performing procedures relating to the Company's nuclear decommissioning ARO 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 discounted cash flow model used in management's ARO 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.

/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland
February 16, 2023

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

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2022	2021	2020
Operating revenues			
Operating revenues	$ 24,280	$ 18,461	$ 16,392
Operating revenues from affiliates	160	1,188	1,211
Total operating revenues	24,440	19,649	17,603
Operating expenses			
Purchased power and fuel	17,457	12,157	9,592
Purchased power and fuel from affiliates	5	6	(7)
Operating and maintenance	4,797	3,934	4,613
Operating and maintenance from affiliates	44	621	555
Depreciation and amortization	1,091	3,003	2,123
Taxes other than income taxes	552	475	482
Total operating expenses	23,946	20,196	17,358
Gain on sales of assets and businesses	1	201	11
Operating income (loss)	495	(346)	256
Other income and (deductions)			
Interest expense, net	(250)	(282)	(328)
Interest expense to affiliates	(1)	(15)	(29)
Other, net	(786)	795	937
Total other income and (deductions)	(1,037)	498	580
(Loss) income before income taxes	(542)	152	836
Income taxes	(388)	225	249
Equity in losses of unconsolidated affiliates	(13)	(10)	(8)
Net (loss) income	(167)	(83)	579
Net (loss) income attributable to noncontrolling interests	(7)	122	(10)
Net (loss) income attributable to common shareholders	$ (160)	$ (205)	$ 589
Comprehensive income (loss), net of income taxes			
Net (loss) income	$ (167)	$ (83)	$ 579
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(6)	—	—
Actuarial loss reclassified to periodic cost	101	—	—
Pension and non-pension postretirement benefit plans valuation adjustment	186	—	—
Unrealized loss on cash flow hedges	(1)	(1)	(2)
Unrealized (loss) gain on foreign currency translation	(3)	—	4
Other comprehensive income (loss), net of income taxes	277	(1)	2
Comprehensive income (loss)	$ 110	$ (84)	$ 581
Comprehensive (loss) income attributable to noncontrolling interests	(7)	122	(10)
Comprehensive income (loss) attributable to common shareholders	$ 117	$ (206)	$ 591
Average shares of common stock outstanding:			
Basic	328	—	—
Assumed exercise and/or distributions of stock-based awards	1	—	—
Diluted	329	—	—
Earnings per average common share			
Basic	$ (0.49)	$ —	$ —
Diluted	$ (0.49)	$ —	$ —

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2022	2021	2020
Cash flows from operating activities			
Net (loss) income	$ (167)	$ (83)	$ 579
Adjustments to reconcile net (loss) income to net cash flows (used in) provided by operating activities			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	2,427	4,540	3,636
Asset impairments	—	545	563
Gain on sales of assets and businesses	(1)	(201)	(11)
Deferred income taxes and amortization of ITC	(643)	(205)	78
Net fair value changes related to derivatives	986	(568)	(270)
Net realized and unrealized losses (gains) on NDT funds	794	(586)	(461)
Net realized and unrealized losses (gains) on equity investments	13	160	(186)
Other non-cash operating activities	249	(605)	18
Changes in assets and liabilities:			
Accounts receivable	(868)	(616)	1,125
Receivables from and payables to affiliates, net	20	14	24
Inventories	(228)	(68)	(77)
Accounts payable and accrued expenses	1,142	346	(343)
Option premiums paid, net	(177)	(338)	(139)
Collateral (posted) received, net	(351)	(130)	479
Income taxes	162	256	186
Pension and non-pension postretirement benefit contributions	(237)	(259)	(255)
Other assets and liabilities	(5,474)	(3,540)	(4,362)
Net cash flows (used in) provided by operating activities	(2,353)	(1,338)	584
Cash flows from investing activities			
Capital expenditures	(1,689)	(1,329)	(1,747)
Proceeds from NDT fund sales	4,050	6,532	3,341
Investment in NDT funds	(4,271)	(6,673)	(3,464)
Collection of DPP, net	4,964	3,902	3,771
Proceeds from sales of assets and businesses	52	878	46
Other investing activities	(2)	(28)	11
Net cash flows provided by investing activities	3,104	3,282	1,958
Cash flows from financing activities			
Change in short-term borrowings	257	362	20
Proceeds from short-term borrowings with maturities greater than 90 days	—	880	500
Repayments of short-term borrowings with maturities greater than 90 days	(1,180)	—	—
Issuance of long-term debt	14	152	3,155
Retirement of long-term debt	(1,162)	(105)	(4,334)
Retirement of long-term debt to affiliate	(258)	—	(550)
Change in money pool with Exelon	—	(285)	285
Acquisition of CENG noncontrolling interest	—	(885)	—
Distributions to Exelon	—	(1,832)	(1,734)
Contributions from Exelon	1,750	64	64
Dividends paid on common stock	(185)	—	—
Other financing activities	(35)	(46)	(70)
Net cash flows used in financing activities	(799)	(1,695)	(2,664)
(Decrease) increase in cash, restricted cash, and cash equivalents	(48)	249	(122)
Cash, restricted cash, and cash equivalents at beginning of period	576	327	449
Cash, restricted cash, and cash equivalents at end of period	$ 528	$ 576	$ 327
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (23)	$ 96	$ (88)
Increase in DPP	5,166	3,652	4,441
Increase in PP&E related to ARO update	343	618	850

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 422	$ 504
Restricted cash and cash equivalents	106	72
Accounts receivable		
Customer accounts receivable (net of allowance for credit losses of $46 and $55 as of December 31, 2022 and December 31, 2021, respectively)	2,585	1,669
Other accounts receivable (net of allowance for credit losses of $5 as of December 31, 2022 and December 31, 2021)	731	592
Mark-to-market derivative assets	2,368	2,169
Receivables from affiliates	—	160
Inventories, net		
Natural gas, oil, and emission allowances	429	284
Materials and supplies	1,076	1,004
Renewable energy credits	617	520
Other	1,026	1,007
Total current assets	9,360	7,981
Property, plant, and equipment (net of accumulated depreciation and amortization of $16,726 and $15,873 as of December 31, 2022 and 2021, respectively)	19,822	19,612
Deferred debits and other assets		
Nuclear decommissioning trust funds	14,114	15,938
Investments	202	174
Mark-to-market derivative assets	1,261	949
Prepaid pension asset	—	1,683
Deferred income taxes	44	32
Other	2,106	1,717
Total deferred debits and other assets	17,727	20,493
Total assets[a]	$ 46,909	$ 48,086

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2022	2021
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 1,159	$ 2,082
Long-term debt due within one year	143	1,220
Accounts payable	2,828	1,757
Accrued expenses	906	737
Payables to affiliates	—	131
Mark-to-market derivative liabilities	1,558	981
Renewable energy credit obligation	901	777
Other	344	311
Total current liabilities	7,839	7,996
Long-term debt	4,466	4,575
Long-term debt to affiliates	—	319
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,031	3,703
Asset retirement obligations	12,699	12,819
Pension obligations	605	—
Non-pension postretirement benefit obligations	609	847
Spent nuclear fuel obligation	1,230	1,210
Payables to affiliates	—	3,357
Payables related to Regulatory Agreement Units	2,897	—
Mark-to-market derivative liabilities	983	513
Other	1,178	1,133
Total deferred credits and other liabilities	23,232	23,582
Total liabilities[(a)]	35,537	36,472
Commitments and contingencies (Note 19)		
Shareholders' Equity		
Predecessor Member's Equity[(b)]	—	11,250
Common stock (No par value, 1,000 shares authorized, 327 shares outstanding as of December 31, 2022)	13,274	—
Retained deficit	(496)	—
Accumulated other comprehensive loss, net	(1,760)	(31)
Total shareholders' equity	11,018	11,219
Noncontrolling interests	354	395
Total equity	11,372	11,614
Total liabilities and shareholders' equity	$ 46,909	$ 48,086

(a) Our consolidated assets include $2,641 million and $2,549 million at December 31, 2022 and 2021, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,041 million and $1,077 million at December 31, 2022 and 2021, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 22–Variable Interest Entities for additional information.

(b) Represents Constellation's predecessor member's equity prior to the separation transaction. Upon completion of the separation, the predecessor member's equity was transferred to CEG Parent's Common stock. See Note 1 — Basis of Presentation for additional information on the separation.

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity

	Shareholder's Equity						
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Deficit	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Predecessor Member's Equity (a)	Total Equity
Balance, December 31, 2019	—	$ —	$ —	$ (32)	$ 2,346	$ 13,516	$ 15,830
Net (loss) income	—	—	—	—	(10)	589	579
Sale of noncontrolling interest	—	—	—	—	—	3	3
Changes in equity of noncontrolling interest	—	—	—	—	(59)	—	(59)
Distribution to member of deferred taxes associated with net retirement benefit obligation	—	—	—	—	—	(9)	(9)
Distribution to member	—	—	—	—	—	(1,734)	(1,734)
Contributions from member	—	—	—	—	—	64	64
Other comprehensive income, net of income taxes	—	—	—	2	—	—	2
Balance, December 31, 2020	—	$ —	$ —	$ (30)	$ 2,277	$ 12,429	$ 14,676
Net income (loss)	—	—	—	—	122	(205)	(83)
Changes in equity of noncontrolling interest	—	—	—	—	(37)	—	(37)
Acquisition of CENG noncontrolling Interest	—	—	—	—	(1,965)	1,080	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	—	—	—	—	—	(288)	(288)
Distribution to member	—	—	—	—	—	(1,832)	(1,832)
Contributions from member	—	—	—	—	—	64	64
Acquisition of noncontrolling interest	—	—	—	—	(2)	2	—
Other comprehensive loss, net of income taxes	—	—	—	(1)	—	—	(1)
Balance, December 31, 2021	—	$ —	$ —	$ (31)	$ 395	$ 11,250	$ 11,614
Net income from January 1, 2022 to January 31, 2022	—	—	—	—	—	151	151
Separation-related adjustments	—	—	—	(2,006)	7	1,802	(197)
Changes in equity of noncontrolling interests from January 1, 2022 to January 31, 2022	—	—	—	—	(7)	—	(7)
Consummation of separation	326,664	13,203	—	—	—	(13,203)	—
Net loss from February 1, 2022 to December 31, 2022	—	—	(311)	—	(7)	—	(318)
Employee incentive plans	466	71	—	—	—	—	71
Changes in equity of noncontrolling interest	—	—	—	—	(34)	—	(34)
Common stock dividends ($0.14/common share)	—	—	(185)	—	—	—	(185)
Other comprehensive income , net of income taxes	—	—	—	277	—	—	277
Balance, December 31, 2022	327,130	$ 13,274	$ (496)	$ (1,760)	$ 354	$ —	$ 11,372

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(a) Represents Constellation's predecessor member's equity prior to the separation transaction. Upon completion of the separation, the predecessor member's equity was transferred to CEG Parent's Common stock. See Note 1 — Basis of Presentation for additional information on the separation.

See the Combined Notes to Consolidated Financial Statements

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

	For the Years Ended December 31,		
(In millions)	**2022**	**2021**	**2020**
Operating revenues			
Operating revenues	$ 24,280	$ 18,461	$ 16,392
Operating revenues from affiliates	160	1,188	1,211
Total operating revenues	24,440	19,649	17,603
Operating expenses			
Purchased power and fuel	17,457	12,157	9,592
Purchased power and fuel from affiliates	5	6	(7)
Operating and maintenance	4,797	3,934	4,613
Operating and maintenance from affiliates	44	621	555
Depreciation and amortization	1,091	3,003	2,123
Taxes other than income taxes	552	475	482
Total operating expenses	23,946	20,196	17,358
Gain on sales of assets and businesses	1	201	11
Operating income (loss)	495	(346)	256
Other income and (deductions)			
Interest expense, net	(250)	(282)	(328)
Interest expense to affiliates	(1)	(15)	(29)
Other, net	(786)	795	937
Total other income and (deductions)	(1,037)	498	580
(Loss) income before income taxes	(542)	152	836
Income taxes	(388)	225	249
Equity in losses of unconsolidated affiliates	(13)	(10)	(8)
Net (loss) income	(167)	(83)	579
Net (loss) income attributable to noncontrolling interests	(7)	122	(10)
Net (loss) income attributable to membership interest	$ (160)	$ (205)	$ 589
Comprehensive income (loss), net of income taxes			
Net (loss) income	$ (167)	$ (83)	$ 579
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(6)	—	—
Actuarial loss reclassified to periodic benefit cost	101	—	—
Pension and non-pension postretirement benefit plans valuation adjustment	186	—	—
Unrealized loss on cash flow hedges	(1)	(1)	(2)
Unrealized (loss) gain on foreign currency translation	(3)	—	4
Other comprehensive income (loss), net of income taxes	277	(1)	2
Comprehensive income (loss)	110	(84)	581
Comprehensive (loss) income attributable to noncontrolling interests	(7)	122	(10)
Comprehensive income (loss) attributable to membership interest	$ 117	$ (206)	$ 591

See the Combined Notes to Consolidated Financial Statements

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

	For the Years Ended December 31,		
(In millions)	2022	2021	2020
Cash flows from operating activities			
Net (loss) income	$ (167)	$ (83)	$ 579
Adjustments to reconcile net (loss) income to net cash flows (used in) provided by operating activities			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	2,427	4,540	3,636
Asset impairments	—	545	563
Gain on sales of assets and businesses	(1)	(201)	(11)
Deferred income taxes and amortization of ITCs	(643)	(205)	78
Net fair value changes related to derivatives	986	(568)	(270)
Net realized and unrealized losses (gains) on NDT funds	794	(586)	(461)
Net realized and unrealized losses (gains) on equity investments	13	160	(186)
Other non-cash operating activities	200	(605)	18
Changes in assets and liabilities:			
Accounts receivable	(855)	(616)	1,125
Receivables from and payables to affiliates, net	65	14	24
Inventories	(228)	(68)	(77)
Accounts payable and accrued expenses	1,112	346	(343)
Option premiums paid, net	(177)	(338)	(139)
Collateral (posted) received, net	(351)	(130)	479
Income taxes	162	256	186
Pension and non-pension postretirement benefit contributions	(237)	(259)	(255)
Other assets and liabilities	(5,540)	(3,540)	(4,362)
Net cash flows (used in) provided by operating activities	(2,440)	(1,338)	584
Cash flows from investing activities			
Capital expenditures	(1,689)	(1,329)	(1,747)
Proceeds from NDT fund sales	4,050	6,532	3,341
Investment in NDT funds	(4,271)	(6,673)	(3,464)
Collection of DPP, net	4,964	3,902	3,771
Proceeds from sales of assets and businesses	52	878	46
Other investing activities	(2)	(28)	11
Net cash flows provided by investing activities	3,104	3,282	1,958
Cash flows from financing activities			
Change in short-term borrowings	257	362	20
Proceeds from short-term borrowings with maturities greater than 90 days	—	880	500
Repayments of short-term borrowings with maturities greater than 90 days	(1,180)	—	—
Issuance of long-term debt	14	152	3,155
Retirement of long-term debt	(1,162)	(105)	(4,334)
Retirement of long-term debt to affiliate	(258)	—	(550)
Change in money pool with Exelon	—	(285)	285
Acquisition of CENG noncontrolling interest	—	(885)	—
Distributions to Exelon	—	(1,832)	(1,734)
Distributions to member	(185)	—	—
Contributions from Exelon	1,750	64	64
Contributions from member	82	—	—
Other financing activities	(57)	(46)	(70)
Net cash flows used in financing activities	(739)	(1,695)	(2,664)
(Decrease) increase in cash, restricted cash, and cash equivalents	(75)	249	(122)
Cash, restricted cash, and cash equivalents at beginning of period	576	327	449
Cash, restricted cash, and cash equivalents at end of period	$ 501	$ 576	$ 327
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (23)	$ 96	$ (88)
Increase in DPP	5,166	3,652	4,441
Increase in PP&E related to ARO update	343	618	850

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2022	2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 403	504
Restricted cash and cash equivalents	98	72
Accounts receivable		
Customer accounts receivable (net of allowance for credit losses of $46 and $55 as of December 31, 2022 and December 31, 2021, respectively)	2,585	1,669
Other accounts receivable (net of allowance for credit losses of $5 as of December 31, 2022 and December 31, 2021)	718	592
Mark-to-market derivative assets	2,368	2,169
Receivables from affiliates	—	160
Inventories, net		
Natural gas, oil, and emission allowance	429	284
Materials and supplies	1,076	1,004
Renewable energy credits	617	520
Other	1,026	1,007
Total current assets	9,320	7,981
Property, plant, and equipment (net of accumulated depreciation and amortization of $16,726 and $15,873 as of December 31, 2022 and 2021, respectively)	19,822	19,612
Deferred debits and other assets		
Nuclear decommissioning trust funds	14,114	15,938
Investments	202	174
Mark-to-market derivative assets	1,261	949
Prepaid pension asset	—	1,683
Deferred income taxes	44	32
Other	2,106	1,717
Total deferred debits and other assets	17,727	20,493
Total assets[a]	$ 46,869	$ 48,086

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2022	2021
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 1,159	$ 2,082
Long-term debt due within one year	143	1,220
Accounts payable	2,810	1,757
Accrued expenses	869	737
Payables to affiliates	45	131
Mark-to-market derivative liabilities	1,558	981
Renewable energy credit obligation	901	777
Other	344	311
Total current liabilities	7,829	7,996
Long-term debt	4,466	4,575
Long-term debt to affiliates	—	319
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,031	3,703
Asset retirement obligations	12,699	12,819
Pension obligations	605	—
Non-pension postretirement benefit obligations	609	847
Spent nuclear fuel obligation	1,230	1,210
Payables to affiliates	—	3,357
Payables related to Regulatory Agreement Units	2,897	—
Mark-to-market derivative liabilities	983	513
Other	1,106	1,133
Total deferred credits and other liabilities	23,160	23,582
Total liabilities[(a)]	35,455	36,472
Commitments and contingencies (Note 19)		
Equity		
Member's equity		
Membership interest	12,408	10,482
Undistributed earnings	412	768
Accumulated other comprehensive loss, net	(1,760)	(31)
Total member's equity	11,060	11,219
Noncontrolling interests	354	395
Total equity	11,414	11,614
Total liabilities and equity	$ 46,869	$ 48,086

(a) Our consolidated assets include $2,641 million and $2,549 million as of December 31, 2022 and 2021, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,041 million and $1,077 million as of December 31, 2022 and 2021, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 22–Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Member's Equity: Membership Interest	Member's Equity: Undistributed Earnings	Member's Equity: Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
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)
Distribution to member	—	(1,734)	—	—	(1,734)
Contribution 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)
Distribution to member	—	(1,832)	—	—	(1,832)
Contribution from member	64	—	—	—	64
Acquisition of noncontrolling interest	2	—	—	(2)	—
Other comprehensive loss, net of income taxes	—	—	(1)	—	(1)
Balance, December 31, 2021	$ 10,482	$ 768	$ (31)	$ 395	$ 11,614
Net loss	—	(160)	—	(7)	(167)
Separation-related adjustments	1,844	(11)	(2,006)	7	(166)
Changes in equity of noncontrolling interest	—	—	—	(41)	(41)
Distribution to member	—	(185)	—	—	(185)
Contributions from member	82	—	—	—	82
Other comprehensive income, net of income taxes	—	—	277	—	277
Balance, December 31, 2022	$ 12,408	$ 412	$ (1,760)	$ 354	$ 11,414

See the Combined Notes to Consolidated Financial Statements

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

1. Basis of Presentation

Description of Business

We are a producer of clean energy and a supplier of energy products and services. Our generating capacity includes primarily 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 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, the separation was completed and CEG Parent holds all the interests in Constellation previously held by Exelon.

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 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. CEG Parent's prior period financial statements have been adjusted to reflect the balances of Constellation in accordance with applicable guidance. Amounts disclosed relate to CEG Parent and Constellation unless specifically noted as relating to CEG Parent only. Unless otherwise indicated or the context otherwise requires, references herein to the terms "we," "us," and "our" refer collectively to CEG Parent and 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 22 — 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 consolidated 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.

Separation from Exelon

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, on the basis of one such share for every three shares of Exelon common stock held on January 20, 2022, the record date of the distribution. We are an independent, publicly traded company listed on the Nasdaq Stock Market 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.

In order to govern the ongoing relationships with Exelon 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 and Exelon 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 Exelon and the allocation and treatment of certain assets and liabilities relating to our employees and former employees
- Tax Matters Agreement (TMA) - governs the respective rights, responsibilities, and obligations between us and Exelon 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 for additional information on these facility agreements.

Beginning on February 1, 2022, the amounts Exelon billed us for services pursuant to the TSA were $266 million for the year ended December 31, 2022, and the amounts we billed Exelon for services pursuant to the TSA were $43 million for the year ended December 31, 2022.

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 in revenues. 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 23 — 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 temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. ITCs 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, 2022 and 2021, restricted cash and cash equivalents primarily represented the payment of medical, dental, vision, and long-term disability benefits and 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 23 — 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. 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 22 — 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. 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 and Equity Investments within NDT funds. We have debt and equity securities held in our NDT funds which are measured and recorded at fair value. Realized and unrealized gains and losses, net of tax, on our NDT funds associated with the Regulatory Agreement Units are included in Noncurrent payables related to Regulatory Agreement Units. Realized and unrealized gains and losses, net of tax, on our NDT funds associated with the Non-Regulatory Agreement Units are included in Other, net in the Consolidated Statements of Operations and Comprehensive Income. For 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. Our NDT funds are classified as current or noncurrent assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. See Note 18 — Fair Value of Financial Assets and Liabilities and Note 10 — Asset Retirement Obligations for additional information.

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. See Note 18 — Fair Value of Financial Assets for additional information.

Equity Security Investments with Readily Determinable Fair Values. We have certain 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 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. Certain assets follow the unitary method of depreciation and recognize gains and losses in the period of replacement or retirement. These gains and losses are recorded in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

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. Most projects will use a debt rate calculated using the general corporate debt pool. In some cases, projects are specifically financed and use a project specific debt rate, which is excluded from the general corporate debt pool. 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 23 — 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, inclusive of ARC, 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 23 — Supplemental Financial Information for additional information regarding nuclear fuel.

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 related to Regulatory Agreement Units. See Note 10 — Asset Retirement Obligations for additional information.

Accounting Implications of the Regulatory Agreement Units 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 noncurrent payables in the Consolidated Balance Sheets (within Payables related to Regulatory Agreement Units). See Note 10 — Asset Retirement Obligations 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. Generally, pre-tax impairment losses are recorded in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. 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. These impairment losses are recorded in Equity in (losses) earnings of unconsolidated affiliates in the Consolidated Statements of Operations and Comprehensive Income.

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 Other, net in the Consolidated Statements of Operations and Comprehensive Income. 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 Other, net in the Consolidated Statements of Operations and Comprehensive Income 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 revenues, Purchased power and fuel, or Interest expense 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 Operating revenues 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

Prior to separation, 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.

Effective upon separation, we sponsor defined benefit pension and OPEB plans as described in Note 15 — Retirement Benefits. The plan obligations and costs of providing benefits under these plans were measured upon separation as of February 1, 2022 and remeasured as of December 31, 2022. The measurement involved various factors, assumptions, and accounting elections. The impact of assumption changes or experience different from that assumed on pension and OPEB obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses more than the greater of ten percent of the PBO or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Gains or losses more than the greater of ten percent of the APBO or the MRV of plan assets are amortized over the average future remaining lifetime of the current inactive population for the OPEB plans.

We report the pension and OPEB service cost and non-service cost (credit) components of net periodic benefit costs (credits) for all plans separately in our Consolidated Statements of Operations and Comprehensive Income. Effective February 1, 2022, the service cost component continues to 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 (credit) components are included in Other, net, in accordance with single employer plan accounting.

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 owned 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.

On April 1, 2014, we entered into various agreements with EDF including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others. 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 included, 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 Member's 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 equity interest[(a)]	(288)
Change from net loss attributable to membership interest and transfers from noncontrolling interest	$ 587

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(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 MWs of generation in operation or under construction across more than 600 sites across the United States. We retained 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.

Agreement for Sale of Our 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 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.

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

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

As a result of the event and outages, we incurred a loss of approximately $800 million for the year ended December 31, 2021. The estimated impact reduced our overall Net loss by approximately $50 million for the year ended December 31, 2022, attributable to a payment to ERCOT from a defaulting market participant, the bankruptcy settlement of a defaulting ERCOT market participant, and the settlement of a dispute related to gas penalties.

In response to the high demand and significantly reduced total generation on the system during the event, the PUCT directed ERCOT to use an administrative price cap of $9,000/MWh during firm load shedding. We intervened in a third-party notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT's action administratively setting prices at $9,000/MWh. Additionally, we filed a request for declaratory judgment in Texas district court. Our request is being stayed at our request pending the outcome of the third party's direct appeal to the Third Court of Appeals on similar grounds, in which briefing is complete, oral argument was held on April 27, 2022. We cannot reasonably predict the outcome of these proceedings or the potential financial statement impact.

Due to the event, several ERCOT market participants experienced bankruptcies or defaulted on payments to ERCOT. As of December 31, 2021, there were approximately $2.5 billion of outstanding defaults. Under ERCOT rules, defaults are allocated to the remaining market participants. Accordingly, we recorded our estimated obligation of the outstanding defaults, net of legislative solutions, and on a discounted basis, of approximately $17 million as of December 31, 2021, which was expected to be paid over a term of 83 years. As of result of a market participant paying off their debt to ERCOT and a bankruptcy settlement, there were no outstanding defaults to be allocated to market participants as of December 31, 2022, as further discussed below.

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 defaults, 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. Securitization of defaults of competitive retail providers has been completed and a market participant securitized its debt and repaid amounts owed to ERCOT, both of which reduced our obligation. 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, and in June 2022, we collected our outstanding receivable. In the first quarter of 2022, a hearing began on ERCOT's $1.9 billion claim in another market participant's bankruptcy for the entire outstanding default owed to ERCOT. The ERCOT claim was resolved through a settlement included in the Chapter 11 Plan of Reorganization filed by the Debtor (market participant) on September 1, 2022 and approved by the bankruptcy court, which became effective on December 15, 2022. The settlement avoids ERCOT allocating outstanding default charges to remaining market participants.

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 either voluntarily waived or sought applicable regulatory approvals to waive the tariff penalties associated with the extreme weather event. 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 March 3, 2022, the KCC approved a unanimous settlement, resolving this matter.

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 has concluded, and we are awaiting the scheduling of oral argument. We cannot reasonably predict the outcome of this proceeding.

New England Regulatory Matters

Mystic Units 8 and 9 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 to 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 EMT 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 Return on Equity ("ROE") using a new methodology. The ROE impacts the return Mystic collects on its rate base under the agreement. 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. In November 2021, FERC issued an order directing a decrease to the ROE used in the Mystic Cost of Service Agreement (the "Mystic COS") from 9.33% to 9.19%. Several parties, including us, have filed petitions for review with the U.S. Court of Appeals for the D.C. Circuit challenging the FERC orders establishing the ROE. These petitions are pending. We do not expect the outcome of this appeal to have a material financial statement impact.

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 EMT. 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. On August 23, 2022, court issued its opinion and remanded several issues back to FERC, which include: (1) the amount of the EMT's fixed costs that can be recovered via the Mystic COS, (2) whether some or all of EMT capital expenditures recovered during the term of the Mystic COS will have to be returned if EMT continues operating after the Mystic COS terminates, and (3) the historical rate base for Mystic upon which we earn a return. We await FERC's order on remand and cannot reasonably predict the outcome of this proceeding, which could have a material financial impact over the term of the Mystic COS.

The Mystic COS requires an annual process whereby we identify and support our projected costs under the agreement and/or true-up previous projections to the actual costs incurred. The first annual process resulted in a filing at FERC on September 15, 2021 and included our projection of capital expenditures to be recovered under the Mystic COS between June 1, 2022 and December 31, 2022. On April 28, 2022, FERC issued an order setting for settlement and/or hearing the issue of whether our projected 2022 capital expenditures can be recovered. Settlement negotiations are currently ongoing. We cannot reasonably predict the outcome of the settlement and/or hearing. On September 15, 2022, we made our second annual filing at FERC, which included (1) our projection of capital expenditures to be recovered under the Mystic COS between January 1, 2023 and December 31, 2023, and (2) an updated projection of the Annual Fixed Revenue Requirement, the Maximum Monthly Fixed Cost Payment, and the Fixed Operating and Maintenance/Return on Investment component of the Monthly Fuel Cost Charge, including an update to rate base for the period between January 1, 2018 and December 31, 2021. That filing is currently pending at FERC.

Following our separation from Exelon, we submitted a filing at FERC to update the capital structure and cost of debt used in the Mystic COS. The Mystic COS had previously used the Exelon capital structure and cost of debt in the rate, and we proposed post-separation to instead use Constellation's capital structure and cost of debt. On May 2, 2022, FERC accepted our filing, subject to refund, and set the matter for settlement and/or hearing. An unopposed offer of settlement was filed at FERC on September 8, 2022 and was approved by FERC on November 2, 2022. The settlement does not have a material financial impact.

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

Inflation Reduction Act of 2022. On August 16, 2022, Congress passed and President Biden signed into law the IRA, which, among other things, includes federal tax credits, certain of which are transferable or fully refundable, for a number of clean energy technologies including existing nuclear plants and hydrogen production facilities. The Nuclear PTC recognizes the contributions of carbon-free nuclear power by providing a federal tax credit of up to $15/MWh, subject to phase-out, beginning in 2024 and continuing through 2032. The Hydrogen PTC provides a 10-year federal tax credit of up to $3/kilogram for clean hydrogen produced after 2022 from facilities that begin construction prior to 2033. Both the Nuclear and Hydrogen PTCs include adjustments for inflation. The Hydrogen PTC creates additional opportunities for our nuclear fleet to enable decarbonization of other industries through the production of clean hydrogen. With this policy support, we expect that many of our nuclear assets will operate through the end of the Nuclear PTC period. Further, the IRA includes a 15% book-minimum tax on applicable corporations that we do not expect to have a material impact to our consolidated financial statements.

Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps. On February 21, 2019, PJM's 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 IMM's 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. On September 2, 2021, FERC issued an order adopting the IMM's 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. Requests for rehearing of FERC's September 2021 order were 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.

PJM MOPR Proceedings. The PJM capacity market includes 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 in capacity auctions. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources.

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 denied rehearing of that order on April 16, 2020. A number of parties, including us, have filed petitions for review of FERC's orders in this proceeding, which are being held in abeyance before the Court of Appeals for the Seventh Circuit. We cannot reasonably predict the outcome of this proceeding. While this litigation remains pending, 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 applied in the capacity auction for the 2023-2024 delivery year and did not restrict the offers of any of our state-supported owned or jointly owned nuclear plants. All of our nuclear units receiving state support cleared in the 2023-24 auction. 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 cannot reasonably predict the outcome of this proceeding.

If our state-supported nuclear plants in PJM are subjected to a MOPR or equivalent without compensation under an FRR or similar program, it could have a material adverse impact on our consolidated 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 December 20, 2022, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating FERC's decision to grant Conowingo its 50-year license renewal and sending the matter back to FERC for further proceedings. The court found that the Clean Water Act prohibits FERC from issuing the new Conowingo license because the process under which MDE provided a waiver of its right to issue a 401 certification was invalid. Upon issuance of the mandate from the U.S. Court of Appeals for the D.C. Circuit, we expect FERC will issue an annual license, which renews automatically, containing the same terms as the license that was in effect prior to the March 19, 2021 FERC order and Conowingo will continue to operate pursuant to that license. We are unable to further predict the outcome of this proceeding at this time. Depreciation provisions continue to assume operation through 2071 given our expectation that a 50-year license will be issued.

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. As a result, Peach Bottom Units 2 and 3 were granted the authority to operate through 2053 and 2054, respectively.

Notwithstanding its 2020 approval, on February 24, 2022, the NRC took action to modify Peach Bottom's subsequently renewed licenses in response to a request for hearing that the NRC had not previously adjudicated. In its February 2022 decision, the NRC reversed itself and concluded that the previous environmental review required by the National Environmental Policy Act (NEPA) for the Peach Bottom subsequently renewed licenses was incomplete because it did not adequately address environmental impacts resulting from renewing the units' licenses for an additional 20 years. As a result, the NRC has undertaken an effort to modify its regulations and guidance to specifically address environmental impacts during the period of subsequent license renewal, which it expects to complete in 2024. In addition, the NRC modified the expiration dates for the Peach Bottom licenses from 2053 and 2054 to 2033 and 2034, respectively, pending the completion of the updated NEPA analysis. On March 7, 2022, we filed a petition requesting that the NRC reevaluate its decision to amend the expiration dates of the Peach Bottom licenses, which the NRC denied on June 3, 2022. In denying our petition, however, the NRC affirmed that the subsequently renewed licenses would otherwise remain in place. We expect that the license expiration dates will be restored to 2053 and 2054, respectively, once the NRC's reevaluation of environmental impacts resulting from subsequent license renewal is complete. On April 5, 2022, the NRC approved a proposed plan to complete the process by April 2024 and to date, the NRC has remained on schedule to meet the April 2024 goal. Depreciation provisions and ARO assumed retirement dates continue to assume Peach Bottom Units 2 and 3 will operate through 2053 and 2054, respectively, given our expectation that the previously approved expiration dates will be restored.

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), CMCs, 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 to 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.

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(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, 2022 and 2021.

(Dollars in millions, unless otherwise noted)

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:

	Contract Assets
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
Amounts reclassified to receivables	(81)
Revenues recognized	62
Balance as of December 31, 2022	$ 130

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 deferred credits and other 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 an annual cap on the total consideration to be received by us for each delivery period. The ZEC price is established on a per MWh of production basis with a maximum annual cap for total compensation to be received in a delivery period, while requiring delivery of all ZECs produced by our participating facilities during each delivery period. ZECs delivered to Illinois utilities in excess of the annual cost cap may be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year.

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

	Contract Liabilities
Balance as of December 31, 2019	$ 71
Consideration received or due	282
Revenues recognized	(266)
Contracts 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
Consideration received or due	339
Revenues recognized	(367)
Balance as of December 31, 2022	$ 47

The following table reflects revenues recognized in the years ended December 31, 2022, 2021 and 2020, which were included in contract liabilities at December 31, 2021, 2020, and 2019, respectively.

(Dollars in millions, unless otherwise noted)

	2022	2021	2020
Revenues recognized	$ 71	$ 82	$ 64

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, 2022. 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.

	2023	2024	2025	2026	2027 and thereafter	Total
Remaining performance obligations	$ 221	$ 78	$ 35	$ 15	$ 136	$ 485

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 FRCC, MISO's Southern Region, and the remaining portions of SERC not included within MISO or PJM.
  - **West** represents operations in 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 Operating 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, prior to the separation. 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 wholesale and retail sales of natural gas, as well as other miscellaneous business activities that are not significant to our overall 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, 2022, 2021, and 2020.

	2022				
	Revenues from external customers[(a)]				
	Contracts with customers	Other[(b)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 5,264	$ (105)	$ 5,159	$ 5	$ 5,164
Midwest	5,164	(507)	4,657	(7)	4,650
New York	2,004	(408)	1,596	(1)	1,595
ERCOT	954	602	1,556	(13)	1,543
Other Power Regions	5,035	1,681	6,716	16	6,732
Total Competitive Businesses Electric Revenues	$ 18,421	$ 1,263	$ 19,684	$ —	$ 19,684
Competitive Businesses Natural Gas Revenues	2,559	2,408	4,967	—	4,967
Competitive Businesses Other Revenues[(c)]	591	(802)	(211)	—	(211)
Total Consolidated Operating Revenues	$ 21,571	$ 2,869	$ 24,440	$ —	$ 24,440

(Dollars in millions, unless otherwise noted)

	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

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. See Note 24 — Related Party Transactions for additional information.
(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 $1,188 million and $633 million and gains of $110 million for the years ended December 31, 2022, 2021, and 2020, respectively.

(Dollars in millions, unless otherwise noted)

	2022			2021			2020		
	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	$ 2,129	$ 9	$ 2,138	$ 2,247	$ 17	$ 2,264	$ 2,174	$ 30	$ 2,204
Midwest	2,765	(1)	2,764	2,717	—	2,717	2,902	—	2,902
New York	1,061	6	1,067	1,151	10	1,161	983	14	997
ERCOT	503	(96)	407	(668)	(157)	(825)	407	19	426
Other Power Regions	952	(31)	921	984	(93)	891	759	(94)	665
Total RNF for Reportable Segments	$ 7,410	$ (113)	$ 7,297	$ 6,431	$ (223)	$ 6,208	$ 7,225	$ (31)	$ 7,194
Other[(b)]	(432)	113	(319)	1,055	223	1,278	793	31	824
Total RNF	$ 6,978	$ —	$ 6,978	$ 7,486	$ —	$ 7,486	$ 8,018	$ —	$ 8,018

(a) Includes purchases and sales from/to third parties and affiliated sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. See Note 24 — Related Party Transactions for additional information.
(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:
- Unrealized mark-to-market losses of $1,013 million, and gains of $565 million, and $295 million for the years ended December 31, 2022, 2021, and 2020, respectively;
- Accelerated nuclear fuel amortization associated with the announced early plant retirements as discussed in Note 7 - Early Plant Retirements of $148 million, and $60 million for the years ended December 31, 2021, and 2020, respectively; and
- The elimination of intersegment RNF.

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, which does not include any allowance related to the sales of Customer Accounts Receivable disclosed below. Allowance for Credit Losses on Other Accounts Receivable was not material as of the balance sheet dates.

Balance as of December 31, 2020	$ 32
Plus: Current period provision for expected credit losses	30
Less: Write-offs, net of recoveries[(a)]	7
Balance as of December 31, 2021	55
Plus: Current period provision for expected credit losses	9
Less: Write-offs, net of recoveries[(a)]	18
Balance as of December 31, 2022	$ 46

(a) Recoveries were not material.

Unbilled Customer Revenue

We recorded $564 million and $373 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of December 31, 2022 and 2021, 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"). On August 16, 2022, we entered into an amendment on the Facility, which increased the maximum funding limit of the Facility from $900 million to $1.1 billion and extended the term of the Facility through August 15, 2025, unless renewed by the mutual consent of the parties in accordance with its terms. 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.

(Dollars in millions, unless otherwise noted)

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.

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

	As of December 31,	
	2022	2021
Derecognized receivables transferred at fair value	$ 1,615	$ 1,265
Cash proceeds received	1,100	900
DPP	515	365

	For the Years Ended December 31,		
	2022	2021	2020
Loss on sale of receivables[(a)]	$ 69	$ 36	$ 30

(a) Reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. This represents the amount by which the accounts receivable sold into the Facility are discounted, limited to credit losses.

	For the Years Ended December 31,		
	2022	2021	2020
Proceeds from new transfers[(a)]	$ 6,108	$ 6,095	$ 2,816
Cash collections received on DPP and reinvested in the Facility[(b)]	4,764	3,502	3,771
Cash collections reinvested in the Facility	10,872	9,597	6,587

(a) Customer accounts receivable sold into the Facility were $11,274 million and $9,747 million for the years ended December 31, 2022 and 2021, respectively.
(b) Does not include the $200 million in net cash proceeds received from the Purchasers in 2022 and $400 million in cash proceeds received from the Purchasers in 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. 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 22 — Variable Interest Entities for additional information.

(Dollars in millions, unless otherwise noted)

Other Sales of Customer Accounts Receivables

We are required, under supplier tariffs, to sell customer receivables to utility companies, which included Exelon's utility subsidiaries prior to the separation. The following table presents the total receivables sold.

	For the Years Ended December 31,		
	2022	2021	2020
Total receivables sold	$ 423	$ 147	$ 824
Related party transactions:			
Receivables sold to Exelon's utility subsidiaries prior to the separation on February 1, 2022	4	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. We remain committed to continued operations for our nuclear plants receiving state-supported payments under the Illinois CMC (Byron, Dresden, and Braidwood), 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. With the passage of the IRA, we expect that many of our nuclear assets will operate at least through the end of the Nuclear PTC period, concluding at the end of 2032. To enable long term operations, we plan to file applications to extend the licenses of our Nuclear fleet to 80 years for the units that receive continued support under federal or state policies or a combination of both. We are currently seeking license renewals for our Clinton and Dresden units. We have updated our depreciation provisions and ARO assumed retirement dates for these assets in the third quarter of 2022 to reflect an additional 20 years of operation. We continuously evaluate factors that affect the current and expected economic value of our plants including current and projected market conditions and policy support.

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. On September 15, 2021, we announced that we have reversed our previous decision to retire Byron and Dresden given the opportunity for additional revenue under the Illinois Clean Energy Law. Our Byron, Dresden, and Braidwood nuclear plants 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.

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.

The total impact for the years ended December 31, 2021 and 2020 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 is summarized in the table below.

(Dollars in millions, unless otherwise noted)

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

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(a) Includes the accelerated depreciation of plant assets including any ARC.
(b) For 2020, reflects the net impacts associated with the remeasurement of the ARO. See Note 10 - Asset Retirement Obligations for additional information.
(c) 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.

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 to 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 an immaterial amount of incremental Depreciation and amortization expense for the year ended December 31, 2022. 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, 2022 and 2021:

Asset Category	December 31, 2022	December 31, 2021
Electric	$ 30,804	$ 29,910
Nuclear fuel[(a)]	5,106	5,166
Construction work in progress	630	399
Other property, plant, and equipment	8	10
Total property, plant, and equipment	36,548	35,485
Less: accumulated depreciation[(b)]	16,726	15,873
Property, plant, and equipment, net	$ 19,822	$ 19,612

(a) Includes nuclear fuel that is in the fabrication and installation phase of $937 million and $859 million as of December 31, 2022 and 2021, respectively.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,657 million and $2,765 million as of December 31, 2022 and 2021, 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 generally correspond with the term of the operating licenses, except for Peach Bottom, Conowingo, Clinton, and Dresden. Peach Bottom Units 2 and 3 depreciation provisions are based on an estimated useful life through 2053 and 2054, respectively. Conowingo depreciation provisions are based on an estimated useful life through 2071. These depreciation provisions are in anticipation of the license expiration dates being restored. We are currently seeking license renewals for our Clinton and Dresden units. Clinton depreciation provisions are based on an estimated useful life through 2047. Dresden Units 2 and 3 depreciation provisions are based on an estimated useful life through 2049 and 2051, respectively, in anticipation of the license renewals. 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 renewals for Peach Bottom, Conowingo, Clinton, and Dresden. See Note 7 — Early Plant Retirements for additional information on the impacts related to Byron, Dresden and Mystic.

Annual depreciation rates for electric generation were 3.46%, 8.67%, and 6.11% for the years ended December 31, 2022, 2021, and 2020, 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 $25 million, $15 million, and $22 million for the years ended December 31, 2022, 2021, and 2020, respectively.

See Note 1 — Basis of Presentation 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, 2022 and 2021 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, 2022				
Plant in service	$ 1,243	$ 1,534	$ 772	$ 1,063
Accumulated depreciation	761	659	328	256
Construction work in progress	7	12	23	26
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 undivided ownership interests are financed with our funds and all operations are proportionately consolidated consistent with our ownership interest. 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 nuclear decommissioning obligations 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.

The following table provides a rollforward of the nuclear decommissioning AROs reflected in the Consolidated Balance Sheets from December 31, 2020 to December 31, 2022:

Balance as of December 31, 2020	$ 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
Net decrease due to changes in, and timing of, estimated future cash flows	(648)
Accretion expense	532
Costs incurred related to decommissioning plants	(60)
Balance as of December 31, 2022[(a)]	$ 12,500

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(a) Includes $40 million and $72 million as the current portion of the ARO as of December 31, 2022 and 2021, respectively, which is included in Other current liabilities in the Consolidated Balance Sheets.

The net $648 million decrease in the ARO during 2022 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments, including the following:

- A net decrease of approximately $790 million due to an increase in discount rates partly offset by an increase in cost escalation rates, primarily labor and energy.
- A decrease of approximately $235 million due to changes in assumed retirement dates as a result of the passage of the IRA and useful life extension for Clinton and Dresden plants. See Note 3 - Regulatory Matters and Note 7 - Early Plant Retirements for additional information.
- A increase of approximately $320 million due to revisions to the projected decommissioning schedule for our New York nuclear plants in connection with our separation from Exelon as discussed further below.
- A net increase of approximately $75 million due to higher estimated decommissioning costs resulting from the completion of updated cost studies for our New York nuclear plants, Quad Cities, Calvert Cliffs, and Three Mile Island.

The 2022 ARO updates resulted in a decrease of $226 million in Operating and maintenance expense for the year ended December 31, 2022 in the Consolidated Statement of Operations and Comprehensive Income.

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, including the following:

- 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 an increase of $51 million in Operating and maintenance expense for the year ended December 31, 2021 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, 2022, PECO filed its Nuclear Decommissioning Cost Adjustment with the PAPUC proposing an annual recovery from customers of approximately $4 million. On August 19, 2022, the PAPUC approved the filing, and the new rates became effective January 1, 2023.

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 $14,127 million and $16,064 million as of December 31, 2022 and 2021, respectively. The NDT funds also include $13 million and $126 million for the current portion of the NDT funds as of December 31, 2022 and 2021, respectively, which are included in Other current assets in the Consolidated Balance Sheets. See Note 23 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

See Note 1 — Basis of Presentation for additional information on the accounting policy for Regulatory Agreement Units with ComEd and PECO.

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 Statements of Operations and Comprehensive Income results in an equal adjustment to noncurrent payables or noncurrent receivables. Any changes to the existing PECO regulatory agreements could impact our ability to offset decommissioning-related activities in the Consolidated Statements of Operations and Comprehensive Income, and the potential impact to our consolidated 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. 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.

(Dollars in millions, unless otherwise noted)

The following table presents our noncurrent payables to ComEd and PECO which are recorded as Payables related to Regulatory Agreement Units as of December 31, 2022 and noncurrent Payables to affiliates as of December 31, 2021:

	December 31, 2022	December 31, 2021
ComEd	$ 2,660	$ 2,760
PECO	237	597

As of December 31, 2022, 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 for the Non-Regulatory Agreement Units are reflected in the Consolidated Statements of Operations and Comprehensive Income within Operating and maintenance expense, Depreciation and amortization expense, and in Other, net.

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, 2022, the ARO associated with Zion's SNF storage facility is $138 million and the NDT funds available to fund this obligation are $58 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, 2022 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, 2022 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 6.2% to 6.9% (as compared to a historical 5-year annual average pre-tax return of approximately 5.3%).

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.

On March 23, 2022, we filed our annual decommissioning funding status report with the NRC for our shutdown units (excluding Zion station for the reason noted above). The annual status report demonstrated adequate decommissioning funding assurance, based on the value of the trust funds as of December 31, 2021 for all of our shutdown reactors except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund, collections from PECO customers, and the ability to adjust those collections in accordance with the approved PAPUC tariff. See NDT Funds section above for additional information.

We will file the next decommissioning funding status report with the NRC by March 31, 2023. This report will also reflect the status of decommissioning funding as of December 31, 2022 for all units. We expect the annual status report to demonstrate adequate decommissioning funding assurance, based on the value of trust funds as of December 31, 2022 for all reactors except for Peach Bottom Unit 1 and Clinton. We are currently seeking to renew Clinton’s operating license for an additional 20 years and anticipate NRC approval by 2026. Once approved, we expect that Clinton will demonstrate adequate funding assurance. In the event that Clinton remains underfunded by April 2024, additional financial assurance may be required. Financial assurance for decommissioning of Peach Bottom Unit 1 is provided by the collections from PECO customers as noted above.

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.

(Dollars in millions, unless otherwise noted)

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, there was an increase to the AROs, as noted above, associated with our New York nuclear plants during the first quarter of 2022.

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 were to fall below investment grade.

See Note 1 — Basis of Presentation 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 — Basis of Presentation 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, 2020 to December 31, 2022:

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
Net increase due to changes in, and timing of, estimated future cash flows		18
Accretion expense		11
Asset divestitures		(1)
Payments		(5)
Balance as of December 31, 2022	$	239

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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, 2022. We did not have material finance leases in 2022, 2021, or in 2020.

	In Years
Remaining lease terms	1-33
Options to extend the term	2-30
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,		
	2022	2021	2020
Operating lease costs	$ 109	$ 161	$ 194
Variable lease costs	169	168	234

(a) Excludes $49 million, $44 million, $44 million of sublease income recorded for each of the years ended December 31, 2022, 2021, and 2020 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,	
	2022	2021
Operating lease ROU assets[(a)]		
Other deferred debits and other assets	$ 545	$ 604
Operating lease liabilities[(a)]		
Other current liabilities	67	72
Other deferred credits and other liabilities	643	705
Total operating lease liabilities	$ 710	$ 777

(a) The operating ROU assets and lease liabilities include $248 million and $377 million, respectively, related to contracted generation as of December 31, 2022, and $293 million and $429 million, respectively, as of December 31, 2021.

The weighted average remaining lease terms, in years, and the weighted average discount rates for operating leases as of December 31, 2022 were as follows:

	As of December 31,		
	2022	2021	2020
Weighted average remaining lease term	9.3	10.1	10.5
Weighted average discount rate	5.0 %	5.0 %	4.9 %

The following table reconciles the undiscounted cash flows for our operating leases to the operating lease liabilities recorded on our consolidated balance sheet as of December 31, 2022:

Year	Amount
2023	$ 101
2024	99
2025	102
2026	102
2027	100
Thereafter	421
Total lease payments	925
Less: Imputed interest	215
Operating lease liabilities	$ 710

(Dollars in millions, unless otherwise noted)

Supplemental cash flow information related to operating leases was as follows:

	For the Years Ended December 31,		
	2022	2021	2020
Cash paid for amounts included in the measurement of operating lease liabilities	$ 114	$ 162	$ 204
ROU assets obtained in exchange for operating lease obligations	14	2	3

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, 2022.

	In Years
Remaining lease terms	1-18
Options to extend the term	1-20

The components of lease income were as follows:

	For the Years Ended December 31,		
	2022	2021	2020
Operating lease income	$ 51	$ 47	$ 47
Variable lease income	258	261	282

The following table presents maturity analysis of the lease payments we expect to receive as of December 31, 2022:

Year	Amount
2023	$ 48
2024	48
2025	48
2026	49
2027	49
Thereafter	133
Total	$ 375

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. Generally, pre-tax impairment losses on long-lived assets or asset groups are recorded in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

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.

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.

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, 2022 and 2021. 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, 2022			December 31, 2021		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Unamortized Energy Contracts	$ 1,960	$ (1,708)	$ 252	$ 1,963	$ (1,673)	$ 290
Customer Relationships	356	(265)	91	330	(243)	87
Trade Name	222	(222)	—	222	(218)	4
Total	$ 2,538	$ (2,195)	$ 343	$ 2,515	$ (2,134)	$ 381

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2022, 2021, and 2020:

For the Years Ended December 31,	Amortization Expense[(a)]
2022	$ 61
2021	80
2020	81

(a) See Note 23 — Supplemental Financial Information for additional information related to the amortization of unamortized energy contracts.

(Dollars in millions, unless otherwise noted)

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2022:

For the Years Ending December 31,	Estimated Future Amortization Expense
2023	$ 59
2024	56
2025	47
2026	40
2027	27

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, 2022 and 2021:

	December 31, 2022	December 31, 2021
Current REC's	$ 617	$ 520

14. Income Taxes

Components of Income Tax Expense or Benefit

Income taxes are comprised of the following components:

	For the Years Ended December 31,		
	2022[(a)]	2021[(a)]	2020[(a)]
Federal			
Current	$ 219	$ 394	$ 130
Deferred	(655)	(153)	150
ITC amortization	(15)	(15)	(25)
State			
Current	34	36	40
Deferred	29	(37)	(46)
Total	$ (388)	$ 225	$ 249

(a) Negative amounts represent income tax benefit. Positive amounts represent income tax expense.

(Dollars in millions, unless otherwise noted)

Rate Reconciliation

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

	For the Years Ended December 31,		
	2022[(a)]	2021	2020
U.S. federal statutory rate	21.0 %	21.0 %	21.0 %
(Decrease) increase due to:			
State income taxes, net of federal income tax benefit[(c)]	(9.2)	—	0.5
Qualified NDT fund income and losses	46.3	165.1	23.5
Amortization of investment tax credit, including deferred taxes on basis differences	2.2	(9.0)	(2.6)
Production tax credits and other credits	7.7	(28.7)	(5.4)
Noncontrolling interests	(0.3)	(3.0)	3.2
Tax Settlements	—	—	(10.3)
Other[(d)]	3.9	2.6	(0.1)
Effective income tax rate[(b)]	71.6 %	148.0 %	29.8 %

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(a) Positive percentages represent income tax benefit. Negative percentages represent income tax expense.
(b) The change in effective tax rate in 2022 is primarily due to the impacts of higher unrealized NDT losses on Income before income taxes and one-time income tax adjustments.
(c) Includes $30 million related to state rate changes and certain state tax positions.
(d) Primarily related to a $32 million prior period income tax adjustment recorded in 2022.

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax (liabilities) assets, as of December 31, 2022 and 2021 are presented below:

	December 31, 2022	December 31, 2021
Plant basis differences	$ (3,005)	$ (2,812)
Accrual based contracts	(35)	(38)
Derivatives and other financial instruments	43	(172)
Deferred pension and postretirement obligation	287	(274)
Nuclear decommissioning activities	(371)	(912)
Deferred debt refinancing costs	—	15
Tax loss carryforward, net of valuation allowances	67	53
Tax credit carryforward	179	778
Investment in partnerships	(205)	(252)
Other, net	407	312
Deferred income tax liabilities (net)	$ (2,633)	$ (3,302)
Unamortized ITCs	(354)	(369)
Total deferred income tax liabilities (net) and unamortized ITCs	$ (2,987)	$ (3,671)

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, 2022:

(Dollars in millions, unless otherwise noted)

Federal	December 31, 2022
Federal general business credits carryforwards and other carryforwards	$ 178
State	
State net operating losses and other carryforwards	939
Deferred taxes on state tax attributes (net)	78
Valuation allowance on state tax attributes	11
Year in which net operating loss or credit carryforwards will begin to expire	2035

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits:

	Unrecognized tax benefits
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
Change to positions that only affect timing	(5)
Increases based on tax positions related to 2022	29
Increases based on tax positions prior to 2022[(b)]	6
Decreases based on tax positions prior to 2022[(b)]	(55)
Balance as of December 31, 2022	$ 24

(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.
(b) Tax positions prior to 2022 remained with Exelon and are not reflected in this table as of December 31, 2022. See discussion below under the Tax Matters Agreement for responsibility of taxes for this period.

Recognition of unrecognized tax benefits

The following table presents the unrecognized tax benefits that, if recognized, would decrease the effective tax rate:

December 31, 2022	$ 29
December 31, 2021	39
December 31, 2020	39

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

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.

(Dollars in millions, unless otherwise noted)

Description of tax years open to assessment by major jurisdiction

Major Jurisdiction	Open Years(a)
Federal consolidated income tax returns	2010-2021
Illinois unitary corporate income tax returns	2012-2021
New Jersey separate corporate income tax returns	2017-2018
New Jersey combined corporate income tax returns	2019-2021
New York combined corporate income tax returns	2015-2021
Pennsylvania separate corporate income tax returns	2019-2021

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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

Prior to separation, we were a party to an agreement with Exelon and other subsidiaries of Exelon that provided for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provided that each party was 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

Tax Matters Agreement

In connection with the separation, we entered into a Tax Matters Agreement ("TMA") with Exelon. The TMA governs 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 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 each agreed to indemnify each other against any amounts for which such indemnified party is not responsible. Specifically, we will be liable for taxes due and payable in connection with tax returns that we are required to file. We will also 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 Exelon tax sharing agreement then existing. As such, our Consolidated Balance Sheets at separation reflected a payable of $103 million for tax liabilities where we maintain contractual responsibility to Exelon, with $53 million recognized in Accounts payable and $50 million in Noncurrent other liabilities. As of December 31, 2022, we had $18 million in Other accounts receivable, no payables in Accounts payable and $50 million in Noncurrent other liabilities.

Tax Refunds and Attributes. The TMA provides for the allocation of certain pre-closing tax attributes between us and Exelon. Tax attributes 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 be entitled to refunds for taxes for which we are responsible. In addition, it is expected that Exelon will have tax attributes that may be used to offset Exelon's future tax liabilities. A significant portion of such attributes were generated by our business. Upon separation we reclassified $508 million from Deferred income taxes to reflect receivables of $11 million and $497 million in Other accounts receivable and Other deferred debits and other assets, respectively, in the Consolidated Balance Sheets for the tax attributes expected to be utilized by Exelon after separation in accordance with the terms of the TMA. As of December 31, 2022, we had $168 million in Other accounts receivable and $362 million in Other deferred debits and other assets for the reclassified tax attributes.

15. Retirement Benefits

Defined Benefit Pension and OPEB

Effective February 1, 2022, in connection with the separation, pension and OPEB obligations and the related plan assets for participants (inclusive of employees and certain former employees and their beneficiaries assigned to us from Exelon upon separation) were transferred to pension and OPEB plans established by us as the plan sponsor. Most current employees participate in the defined benefit pension and OPEB plans that we sponsor. Newly hired employees are generally not eligible for either pension or OPEB benefits; instead, these employees are eligible to receive an enhanced non-discretionary fixed employer contribution under our sponsored defined contribution savings plan.

As the plan sponsor, effective February 1, 2022, our Consolidated Balance Sheets reflect underfunded pension and OPEB liabilities equal to an excess of either the PBO or APBO over the fair value of the plan assets, consistent with a single employer benefit plan. We no longer account for our interest in Exelon sponsored pension and OPEB plans under the multi-employer benefit plan guidance as we are no longer participants. That previous approach historically resulted in the recognition of a net prepaid pension asset in our Consolidated Balance Sheets representing an excess of contributions over cumulative costs.

Benefit Obligations, Plan Assets, and Funded Status

As of February 1, 2022, we assumed from Exelon the PBO, APBO, and plan assets for our plan participants in connection with the separation. The defined benefit pension and OPEB plans were remeasured to determine the obligations and related plan assets to be transferred to us as of that date. The pension assets allocated to us were based on the rules prescribed by ERISA for transfers of assets in connection with a pension plan separation. A portion of the Exelon OPEB plan assets, which are held in VEBA trusts, were also allocated to us separately for each funding vehicle based on the ratio of the APBO assumed by us to the total APBO attributed to each funding vehicle.

The remeasurement completed at separation is reflected in the table below as a separation-related adjustment and resulted in the recognition of pension obligations of $953 million, net of pension plan assets of $8,267 million, and OPEB obligations of $876 million, net of OPEB plan assets of $904 million. Additionally, we recognized $2,006 million (after-tax) in Accumulated other comprehensive loss for actuarial losses and prior service costs that had accrued over the lives of the plans prior to separation, primarily based on our proportionate share of the total projected pension and OPEB obligations at Exelon prior to separation.

We use a December 31 measurement date for our pension and OPEB obligations and the related plan assets. The actuarial gains experienced upon remeasurement as of December 31, 2022 were offset against AOCI and attributable to increases in the discount rates used to measure the benefit obligations net of actual investment performance that was less than expected.

The following tables provide a rollforward of the changes in the benefit obligations and plan assets for the year ended December 31, 2022 for all plans combined:

(Dollars in millions, unless otherwise noted)

	Pension Benefits	OPEB
Change in benefit obligation:		
Benefit obligation as of the beginning of the year	$ —	$ 847
Separation-related adjustment	9,220	933
Benefit obligation as of February 1, 2022	9,220	1,780
Service cost	115	23
Interest cost	269	52
Plan participants' contributions	—	20
Actuarial gain, net	(1,756)	(401)
Settlements	(15)	—
Gross benefits paid	(558)	(114)
Benefit obligation as of the end of year	$ 7,275	$ 1,360

	Pension Benefits	OPEB
Change in plan assets:		
Prepaid pension asset as of the beginning of year	$ 1,683	$ —
Separation-related adjustment	6,584	904
Fair value of net plan assets as of February 1, 2022	8,267	904
Actual return on plan assets	(1,245)	(99)
Employer contributions	211	—
Plan participants' contributions	—	15
Gross benefits paid	(558)	(86)
Settlements	(15)	—
Fair value of net plan assets as of the end of year	$ 6,660	$ 734

We present our benefit obligations net of plan assets on our Consolidated Balance Sheets within the following line items:

	Pension Benefits		OPEB	
	2022	2021	2022	2021
Prepaid pension asset	$ —	$ 1,683	$ —	$ —
Other current liabilities	(10)	—	(17)	—
Pension obligations	(605)	—	—	—
Non-pension postretirement benefit obligations	—	—	(609)	(847)
(Unfunded) funded status (net benefit obligation less plan assets)	$ (615)	$ 1,683	$ (626)	$ (847)

The following table provides the ABO and fair value of plan assets for all pension plans with an ABO in excess of plan assets. Information for pension and OPEB plans with projected PBO and APBO, respectively, in excess of plan assets has been disclosed in the Obligations and Plan Assets table above as all pension and OPEB plans are underfunded.

ABO in Excess of Plan Assets	December 31, 2022
ABO	$ (7,121)
Fair value of net plan assets	6,660

Components of Net Periodic Benefit Costs (Credits)

(Dollars in millions, unless otherwise noted)

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We report the service cost and other non-service cost (credit) components of net periodic benefit costs (credits) for all plans separately in our Consolidated Statements of Operations and Comprehensive Income. Effective February 1, 2022, the service cost component will continue to 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 (credit) components will now be included in Other, net, in accordance with single employer plan accounting.

Historically, we were allocated our portion of pension and OPEB service and non-service costs (credits) from Exelon, which was included in Operating and maintenance expense. Our portion of the total net periodic benefit costs allocated to us from Exelon in 2022 prior to separation was not material and remains in total Operating and maintenance expense.

The majority of the 2022 pension benefit cost for the plan is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.23%. The majority of the 2022 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.39% for funded plans and a discount rate of 3.21%.

The following table presents the components of our net periodic benefit costs (credits), prior to capitalization and co-owner allocations, for the years ended December 31, 2022, 2021 and 2020:

	Pension Benefits			OPEB			Total Pension Benefits and OPEB		
	2022	2021[(a)]	2020[(a)]	2022	2021[(a)]	2020[(a)]	2022	2021[(a)]	2020[(a)]
Components of net periodic benefit cost (credit):									
Service cost	$ 126	$ 145	$ 137	$ 25	$ 29	$ 34	$ 151	$ 174	$ 171
Non-service components of pension benefits & OPEB cost (credit):									
Interest cost	290	235	280	55	45	61	345	280	341
Expected return on assets	(565)	(493)	(474)	(55)	(58)	(62)	(620)	(551)	(536)
Amortization of:									
Prior service cost (credit)	1	1	1	(7)	(9)	(49)	(6)	(8)	(48)
Actuarial loss (gain)	148	199	164	(1)	10	15	147	209	179
Settlement charges	6	20	9	—	—	(1)	6	20	8
Non-service components of pension benefits & OPEB credit[(b)]	(120)	(38)	(20)	(8)	(12)	(36)	(128)	(50)	(56)
Net periodic benefit cost (credit)[(c)(d)(e)]	$ 6	$ 107	$ 117	$ 17	$ 17	$ (2)	$ 23	$ 124	$ 115

(a) Costs recognized for the years ended December 31, 2021 and 2020 were allocated to us by Exelon under the Exelon sponsored pension and OPEB plans prior to separation.
(b) Effective February 1, 2022, these non-service costs (credits) are reflected in Other, net in the Consolidated Statements of Operations and Comprehensive Income.
(c) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2022 totaled $131 million. The pension benefit and OPEB non-service credits reflected in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2022 totaled ($116) million.

(Dollars in millions, unless otherwise noted)

(d) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2021 totaled $144 million. The pension benefit and OPEB non-service credits reflected in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2021 totaled ($50) million.
(e) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2020 totaled $140 million. The pension benefit and OPEB non-service credits reflected in the Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2020 totaled ($43) million.

Components of AOCI

We recognize the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on our balance sheet, with offsetting entries to AOCI. An updated measurement was performed as of December 31, 2022, the impact of which was recognized in AOCI as an actuarial gain. The following tables provide the pre-tax components of AOCI for the year ended December 31, 2022, for all plans combined:

	Pension Benefits	OPEB
Changes in plan assets and benefit obligations recognized in AOCI:		
Separation related adjustment	$ 2,664	$ 22
Current year actuarial (gain) loss	11	(253)
Amortization of actuarial (loss) gain	(134)	1
Amortization of prior service (cost) credit	(1)	7
Settlements	(6)	—
Total recognized in AOCI	$ 2,534	$ (223)

The following table provides the components of gross accumulated other comprehensive loss that have not been recognized as components of periodic benefit cost as of December 31, 2022, for all plans combined:

	Pension Benefits	OPEB
Prior service cost (credit)	$ 10	$ (30)
Actuarial loss (gain)	2,524	(193)
Total	$ 2,534	$ (223)

Average Remaining Service Period

For pension benefits, we amortize the unrecognized prior service costs (credits) and certain actuarial gains and losses reflected in AOCI, as applicable, based on participants' average remaining service periods.

For OPEB, we amortize the unrecognized prior service costs (credits) reflected in AOCI over participants' average remaining service period to benefit eligibility age, and amortize certain actuarial gains and losses reflected in AOCI over participants' average remaining service period to expected retirement.

The resulting average remaining service periods for pension and OPEB were as follows as of December 31, 2022:

	December 31, 2022
Pension plans	12.2
OPEB plans:	
Benefit Eligibility Age	7.4
Expected Retirement	8.3

Assumptions

The measurement of the plan obligations and costs of providing benefits under our defined benefit pension and OPEB plans involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. The measurement of benefit obligations and costs is impacted by several assumptions and inputs, as shown below, among other factors. When developing the required assumptions, we consider historical information as well as future expectations.

(Dollars in millions, unless otherwise noted)

Expected Rate of Return. In determining the EROA, we consider historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectation regarding future long-term capital market performance, weighted by our target asset class allocations.

Discount Rate. The discount rates are determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and OPEB obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and OPEB plans. The discount rate is the single level rate that produces the same result as the spot rate curve. We utilize an analytical tool developed by our actuaries to determine the discount rates.

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. At separation and upon remeasurement as of December 31, 2022, we utilized the mortality tables and projection scales released by the SOA.

The following assumptions were used to determine the benefit obligations for the plans as of December 31, 2022 and at separation. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits		OPEB	
	December 31, 2022	February 1, 2022	December 31, 2022	February 1, 2022
Discount rate[(a)]	5.52 %	3.23 %	5.50 %	3.21 %
Investment crediting rate[(b)]	5.15 %	3.86 %	N/A	N/A
Rate of compensation increase	3.75 %	3.75 %	3.75 %	3.75 %
Mortality table	Pri-2012 table with MP-2021 improvement scale (adjusted)	Pri-2012 table with MP-2021 improvement scale (adjusted)	Pri-2012 table with MP-2021 improvement scale (adjusted)	Pri-2012 table with MP-2021 improvement scale (adjusted)
Healthcare cost trend on covered charges	N/A	N/A	Initial and ultimate rate of 5.00%	Initial and ultimate rate of 5.00%

(a) The discount rates above represent the blended rates used to establish the majority of Constellation's pension and OPEB costs.
(b) The investment crediting rate above represents a weighted average rate.

Contributions

We consider various factors when making qualified 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, and management of the pension obligation. The Pension Protection 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 over time. This level funding strategy helps minimize the volatility of future period required pension contributions. Based on this funding strategy and current market conditions, which are both subject to change, we made our annual qualified pension contribution totaling $192 million in February 2022.

(Dollars in millions, unless otherwise noted)

Prior to separation, Exelon allocated contributions related to its legacy Exelon sponsored pension and OPEB plans to its subsidiaries based on accounting cost or employee participation (both active and retired). The following tables provide our contributions to the pension and OPEB plans:

Pension benefits		OPEB	
2021	2020	2021	2020
$ 231	$ 236	$ 28	$ 19

Our non-qualified pension plans are not funded given that they are not subject to statutory minimum contribution requirements. OPEB plans are also not subject to statutory minimum contribution requirements, though we have funded certain plans. For our funded OPEB plans, we consider several factors in determining the level of contributions to these plans, including liabilities management and levels of benefit claims paid. The benefit payments to the non-qualified pension plans in 2022 were $20 million and the contributions to the OPEB plans, including benefit payments to unfunded plans were $26 million.

The following table provides our planned contributions to our qualified pension plans, non-qualified pension plans, and OPEB plans in 2023 (including our benefit payments related to unfunded plans):

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Planned contributions	$ 21	$ 10	$ 17

Estimated Future Benefit Payments

Estimated future benefit payments to participants over the next ten years in all pension and OPEB plans as of December 31, 2022 are as follows:

	Pension Benefits	OPEB
2023	$ 525	$ 105
2024	531	105
2025	544	105
2026	541	105
2027	547	106
2028 through 2032	2,792	525
Total estimated future benefits payments through 2032	$ 5,480	$ 1,051

Plan Assets

On a regular basis, we evaluate our investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. We have developed and implemented a liability hedging investment strategy for our qualified pension plans that has reduced the volatility of these pension assets relative to the associated pension obligations. We are likely to continue to gradually increase the liability hedging portfolio as the funded status of the plans improve. The overall objective is to achieve attractive risk-adjusted returns that will balance with the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for our OPEB plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Actual asset returns have an impact on the costs reported for the pension and OPEB plans. The actual asset returns across our pension and OPEB plans for the year ended December 31, 2022 were (18.40)% and (11.20)%, respectively, compared to an expected long-term return assumption of 7.00% and 6.39%, respectively. We used an EROA of 6.50% to estimate both our 2023 pension and OPEB costs.

Our pension and OPEB plan target asset allocations as of December 31, 2022 were as follows:

(Dollars in millions, unless otherwise noted)

Asset Category	Pension Benefits	OPEB
Equity securities	21 %	43 %
Fixed income securities	54 %	45 %
Alternative investments[(a)]	25 %	12 %
Total	100 %	100 %

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(a)Alternative investments include private equity, hedge funds, real estate, and private credit.

We evaluated our pension and OPEB plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2022. 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, 2022, our pension and OPEB plans held no credit risk concentrations surpassing 10% of plan assets.

Fair Value Measurements

The following table presents pension and OPEB plan assets measured and recorded at fair value in our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2022:

(Dollars in millions, unless otherwise noted)

	December 31. 2022				
	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets[a]					
Cash equivalents	$ 216	$ —	$ —	$ —	$ 216
Equities[b]	776	—	—	368	1,144
Fixed income:					
U.S. Treasury and agencies	693	128	—	—	821
State and municipal debt	—	44	—	—	44
Corporate debt	—	1,736	8	—	1,744
Other[b]	—	43	—	470	513
Fixed income subtotal	693	1,951	8	470	3,122
Private equity	—	—	180	585	765
Hedge funds	—	—	—	429	429
Real estate	—	—	—	547	547
Private credit	—	—	—	480	480
Pension plan assets subtotal	1,685	1,951	188	2,879	6,703
OPEB plan assets[a]					
Cash equivalents	40	—	—	—	40
Equities	152	—	—	146	298
Fixed income:					
U.S. Treasury and agencies	10	27	—	—	37
State and municipal debt	—	4	—	—	4
Corporate debt	—	27	—	—	27
Other	57	3	—	111	171
Fixed income subtotal	67	61	—	111	239
Hedge funds	—	—	—	59	59
Real estate	—	—	—	62	62
Private credit	—	—	—	36	36
OPEB plan assets subtotal	259	61	—	414	734
Total pension and OPEB plan assets[c]	$ 1,944	$ 2,012	$ 188	$ 3,293	$ 7,437

(a) See Note 18 — Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.

(Dollars in millions, unless otherwise noted)

(b) Includes derivative instruments of $6 million for the year ended December 31, 2022, which have total notional amounts of $1,879 million as of December 31, 2022. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) Excludes net liabilities of $43 million as of December 31, 2022, which include certain derivative assets that have notional amounts of $41 million as of December 31, 2022. These items are required to reconcile to the fair value of net plan assets and consist primarily of receivables or payables related to pending securities sales and purchases, and interest and dividends receivable.

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and OPEB plans for the year ended December 31, 2022:

Pension Assets	Fixed Income	Equities	Private Equity	Total
Balance as of January 1, 2022	$ —	$ —	$ —	$ —
Separation related adjustment	9	—	—	9
Actual return on plan assets:				
Relating to assets still held as of the reporting date	(1)	—	(54)	(55)
Purchases and settlements:				
Purchases	—	—	18	18
Settlements[(a)]	—	—	(4)	(4)
Transfers into Level 3[(b)]	—	—	220	220
Balance as of December 31, 2022	$ 8	$ —	$ 180	$ 188

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(a) Represents cash settlements only.
(b) Includes certain private equity investments previously measured at fair value using NAV or its equivalent as a practical expedient at separation transferred to Level 3 primarily due to changes in market liquidity or data.

Valuation Techniques Used to Determine Fair Value

The techniques used to fair value the pension and OPEB assets invested in cash equivalents, equities, fixed income, derivatives, private equity, real estate, and private credit investments are the same as the valuation techniques for these types of investments in NDT funds. See Cash Equivalents and NDT Fund Investments in Note 18 — Fair Value of Financial Assets and Liabilities for further information.

Pension and OPEB assets also include investments in hedge funds. Hedge fund investments include those that employ a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. We have the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate.

Defined Contribution Savings Plan

We sponsor the Constellation Employee Savings Plan, a 401(k) defined contribution savings plan consistent with those previously sponsored by Exelon. The plan allows 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. In addition, certain employees are eligible for a fixed non-discretionary employer contribution in lieu of a pension benefit. The matching contributions to the savings plan were $90 million, $53 million and $63 million for the years ended December 31, 2022, December 31, 2021, and 2020, respectively.

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 delivered.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined 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 or procure differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in the prices of electricity, natural gas and oil, 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.

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 our RMC.

The following tables provide a summary of the derivative fair value balances recorded as of December 31, 2022 and 2021:

(Dollars in millions, unless otherwise noted)

December 31, 2022	Economic Hedges	Proprietary Trading	Collateral (a)(b)	Netting(a)	Total
Mark-to-market derivative assets (current assets)	$ 15,296	$ 10	$ 161	$ (13,123)	$ 2,344
Mark-to-market derivative assets (noncurrent assets)	5,100	—	217	(4,074)	1,243
Total mark-to-market derivative assets	20,396	10	378	(17,197)	3,587
Mark-to-market derivative liabilities (current liabilities)	(15,049)	(6)	374	13,123	(1,558)
Mark-to-market derivative liabilities (noncurrent liabilities)	(5,203)	—	146	4,074	(983)
Total mark-to-market derivative liabilities	(20,252)	(6)	520	17,197	(2,541)
Total mark-to-market derivative net assets	$ 144	$ 4	$ 898	$ —	$ 1,046

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	$ 1,103	$ 7	$ 512	$ —	$ 1,622

(a) We net all available amounts allowed in our Consolidated Balance Sheets in accordance with authoritative guidance for derivatives. 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, 2022 and 2021 and not reflected in the table above.
(b) Includes $836 million and $897 million of variation margin held from the exchanges as of December 31, 2022 and 2021, respectively.

Economic Hedges (Commodity Price Risk)

For the years ended December 31, 2022, 2021, and 2020, 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.

	Gains (Losses)		
Income Statement Location	2022	2021	2020
Operating revenues	$ (1,193)	$ (635)	$ 112
Purchased power and fuel	167	1,206	168
Total	$ (1,026)	$ 571	$ 280

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 typically 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, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% and 75%-78% for 2023 and 2024, 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, 2022, 2021, and 2020, net pre-tax commodity mark-to-market gains and losses were not material.

(Dollars in millions, unless otherwise noted)

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 $524 million and $486 million as of December 31, 2022 and 2021, respectively.

The following table provides the mark-to-market derivative assets and liabilities as of December 31, 2022:

December 31, 2022	Economic Hedges	Netting[(a)]	Total
Mark-to-market derivative assets (current assets)	$ 29	$ (5)	$ 24
Mark-to-market derivative assets (noncurrent assets)	18	—	18
Total mark-to-market derivative assets	47	(5)	42
Mark-to-market derivative liabilities (current liabilities)	(5)	5	—
Mark-to-market derivative liabilities (noncurrent liabilities)	—	—	—
Total mark-to-market derivative liabilities	(5)	5	—
Total mark-to-market derivative net assets	$ 42	$ —	$ 42

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(a) We net all available amounts in our Consolidated Balance Sheets in accordance with authoritative guidance for derivatives. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements.

The mark-to-market derivative assets and liabilities as of December 31, 2021 were not material.

The mark-to-market gains and losses associated with management of interest rate and foreign currency exchange rate risk for the years ended December 31, 2022, 2021, and 2020 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, 2022. 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, 2022	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	$ 1,304	$ 135	$ 1,169	—	$ —
Non-investment grade	110	88	22	—	—
No external ratings					
Internally rated — investment grade	106	—	106	—	—
Internally rated — non-investment grade	374	40	334	—	—
Total	$ 1,894	$ 263	$ 1,631	—	$ —

Net Credit Exposure by Type of Counterparty	As of December 31, 2022
Investor-owned utilities, marketers, power producers	$ 1,311
Energy cooperatives and municipalities	112
Financial Institutions	9
Other	199
Total	$ 1,631

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(a) As of December 31, 2022, credit collateral held from counterparties where we had credit exposure included $152 million of cash and $111 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, 2022	2021
Gross fair value of derivative contracts containing this feature[(a)]	$ (4,736)	$ (3,872)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	2,048	2,424
Net fair value of derivative contracts containing this feature[(c)]	$ (2,688)	$ (1,448)

(Dollars in millions, unless otherwise noted)

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(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.
(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, 2022 and 2021, 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,	
	2022	2021
Cash collateral posted[(a)]	$ 1,636	$ 713
Letters of credit posted[(a)]	947	755
Cash collateral held[(a)]	765	182
Letters of credit held[(a)]	115	124
Additional collateral required in the event of a credit downgrade below investment grade (at BB+/Ba1)[(b)(c)]	3,337	2,113

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(a) The cash collateral and letters of credit amounts are inclusive of NPNS contracts.
(b) Certain of our contracts contain provisions that allow a counterparty to request additional collateral when there has been a subjective determination that our credit quality has deteriorated, generally termed “adequate assurance.” Due to the subjective nature of these provisions, we estimate the amount of collateral that we may ultimately be required to post in relation to the maximum exposure with the counterparty.
(c) The downgrade collateral is inclusive of all contracts in a liability position regardless of accounting treatment.

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.

(Dollars in millions, unless otherwise noted)

Commercial Paper

The following table reflects our commercial paper program supported by the revolving credit agreements as of December 31, 2022 and 2021:

Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Weighted Average Interest Rate on Commercial Paper Borrowings at December 31,	
2022[(a)(b)(c)]	2021[(a)(d)]	2022	2021	2022	2021
$ 3,500	$ 5,300	$ 959	$ 702	4.90 %	0.66 %

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(a) Excludes $1,200 million in bilateral credit facilities as of December 31, 2022 and 2021, and $131 million in credit facilities for project finance as of both December 31, 2022 and 2021, respectively. These credit facilities do not back our commercial paper program.
(b) Excludes the liquidity facility, which has a bank commitment of $971 million as of December 31, 2022. This credit facility does not back our commercial paper program.
(c) Excludes customer accounts receivable Facility that has total capacity of $1.1 billion as of December 31, 2022. See Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Excludes $44 million of credit facility agreements arranged at minority and community banks as of December 31, 2021. These facilities expired on October 7, 2022 and were solely utilized to issue letters of credit.

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.

Credit Agreements

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.

As of December 31, 2022, and 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, 2022	
Facility Type	Aggregate Bank Commitment	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper
Syndicated Revolver	$ 3,500	$ —	$ 765	$ 2,735	$ 1,776
Bilaterals	1,200	—	867	333	—
Liquidity Facility	971	—	732	139 [(a)]	—
Project Finance	131	—	111	20	—
Total	$ 5,802	$ —	$ 2,475	$ 3,227	$ 1,776

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(a) The maximum amount of the bank commitment is not to exceed $971 million. The aggregate available capacity of the facility is subject to market fluctuations based on the value of U.S Treasury Securities which determines the amount of collateral held in the trust. We may post additional collateral to borrow up to the maximum bank commitment. As of December 31, 2022, without posting additional collateral, the actual availability of facility, prior to outstanding letters of credit was $871 million.

(Dollars in millions, unless otherwise noted)

Facility Type	Aggregate Bank Commitment[b]	Facility Draws	Outstanding Letters of Credit	Available Capacity as of December 31, 2021	
				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	—
Total	$ 6,631	$ —	$ 2,375	$ 4,256	$ 3,368

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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 the separation.
(b) Excludes $44 million of credit facility agreements arranged at minority and community banks. These facilities expired on October 7, 2022 and were solely utilized to issue letters of credit. As of December 31, 2021, letters of credit issued under these facilities totaled $5 million.

Bilateral Credit Agreements

The following table reflects the bilateral credit agreements at December 31, 2022:

Date Initiated		Latest Amendment Date	Maturity Date(a)	Amount
January 5, 2016	(b)	April 2, 2021	April 5, 2023	$ 150
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	100
November 21, 2019	(b)	November 15, 2022	November 21, 2024	100
May 15, 2020	(b)(d)	February 9, 2022	N/A	200
August 12, 2022	(b)	N/A	N/A	50
August 24, 2022	(b)(c)	N/A	August 23, 2024	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) On January 20, 2023, the bilateral credit agreement decreased to $10 million.
(d) On January 31, 2023, the bilateral credit agreement increased to $250 million.

Borrowings under our revolving credit agreement bear interest at a rate based upon either the Daily Simple SOFR rate or a Term SOFR rate, plus an adder based upon our credit rating. The adders for the Daily Simple SOFR based borrowings and Term SOFR borrowings are 27.5 basis points and 127.5 basis points, respectively.

If we lose our investment grade rating, the maximum adders for Daily Simple SOFR rate borrowings and Term SOFR rate borrowings would be 100 basis points and 200 basis points, respectively. The credit agreements also require us to pay facility fees based upon the aggregate commitments. The fee varies depending upon our credit rating.

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 with an expiration of March 16, 2022. Pursuant to the loan agreement, loans made thereunder beared interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder was unsecured. In connection with the separation, we repaid the term loan on January 26, 2022. The loan agreement was reflected in Short-term borrowings in the Consolidated Balance Sheets as of December 31, 2021.

On March 31, 2020, we entered into a term loan agreement for $300 million. We repaid $100 million of the term loan on March 29, 2022. The remaining $200 million from the loan agreement was renewed on March 29, 2022 and will expire on March 29, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.80% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Short-term borrowings in the Consolidated Balance Sheets.

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 beared 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 was unsecured. The loan agreement was amended on January 24, 2022 to change the maturity date from August 5, 2022 to June 30, 2022. We repaid the term loan on April 15, 2022. The loan was reflected in Short-term borrowings in the Consolidated Balance Sheets as of December 31, 2021. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

On January 26, 2023, we entered into a term loan agreement for $100 million. The loan agreement has an expiration of January 24, 2024. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.8% and all indebtedness thereunder is unsecured.

On February 9, 2023, we entered into a term loan agreement for $400 million. The loan agreement has an expiration of February 8, 2024. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 1.05% and all indebtedness thereunder is unsecured.

Long-Term Debt

The following table presents the outstanding long-term debt as of December 31, 2022 and 2021:

(Dollars in millions, unless otherwise noted)

	Rates		Maturity Date	December 31, 2022	December 31, 2021
Long-term debt					
Senior unsecured notes	3.25 % -	6.25 %	2025 - 2042	$ 2,938	$ 4,219
Notes payable and other	2.10 % -	6.96 %	2023 - 2028	68	103
Nonrecourse debt:					
Fixed rates	2.29 % -	6.00 %	2031 - 2037	839	909
Variable rates	2.99 % -	7.24 %	2026 - 2027	805	870
Total long-term debt				4,650	6,101
Unamortized debt discount and premium, net				(5)	(7)
Unamortized debt issuance costs				(36)	(42)
Fair value adjustment				—	62
Long-term debt due within one year				(143)	(1,220)
Long-term debt				$ 4,466	$ 4,894

Long-term debt maturities in the periods 2023 through 2027 and thereafter are as follows:

2023	$ 143
2024	110
2025	986
2026	121
2027	735
Thereafter	2,555
Total	$ 4,650

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. As of December 31, 2021, we had $319 million recorded to intercompany notes payable to Exelon. In connection with the separation, on January 31, 2022, we paid cash to Exelon in the amount of $258 million to settle the intercompany loan. See Note 1 — Basis of Presentation for additional information.

Debt Covenants

As of December 31, 2022, we are in compliance with all 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, 2022. 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 bears interest at an average blended interest rate of 2.82%. As of December 31, 2022 and 2021, approximately $415 million and $435 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, 2022. 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 MWs. 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, 2022 and December 31, 2021, approximately $345 million and $380 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, 2022, the Continental Wind letter of credit facility had $111 million in letters of credit outstanding related to the project.

In 2017, our interests in Continental Wind were contributed to CRP. Refer to Note 22 - 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, 2022 and December 31, 2021, approximately $80 million and $90 million were outstanding, respectively. In 2017, our interests in RPG were contributed to CRP. Refer to Note 22 - Variable Interest Entities for additional information on CRP.

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 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, 2022 and 2021, $690 million and $735 million was outstanding, respectively. See Note 22 — 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, 2022 and 2021, approximately $115 million and $135 million was outstanding, respectively. See Note 16 — Derivative Financial Instruments for additional information on interest rate swaps.

(Dollars in millions, unless otherwise noted)

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.

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, 2022 and 2021. 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, 2022				December 31, 2021			
	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	$ 4,609	$ 3,688	$ 859	$ 4,547	$ 6,114	$ 5,749	$ 1,093	$ 6,842
SNF Obligation	1,230	1,021	—	1,021	1,210	1,060	—	1,060

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, 2022 and 2021:

(Dollars in millions, unless otherwise noted)

	As of December 31, 2022					As of December 31, 2021				
	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]	$ 41	$ —	$ —	$ —	$ 41	$ 113	$ —	$ —	$ —	$ 113
NDT fund investments										
Cash equivalents[b]	349	88	—	—	437	465	116	—	—	581
Equities	3,462	1,498	—	1,421	6,381	4,564	1,805	—	1,645	8,014
Fixed income										
Corporate debt[c]	—	885	264	—	1,149	—	1,145	286	—	1,431
U.S. Treasury and agencies	1,996	46	—	—	2,042	2,193	30	—	—	2,223
Foreign governments	—	39	—	—	39	—	60	—	—	60
State and municipal debt	—	53	—	—	53	—	26	—	—	26
Other	21	21	—	1,649	1,691	29	23	—	1449	1,501
Fixed income subtotal	2,017	1,044	264	1,649	4,974	2,222	1,284	286	1,449	5,241
Private credit	—	—	159	643	802	—	—	178	624	802
Private equity	—	—	—	687	687	—	—	—	673	673
Real estate	—	—	—	1,014	1,014	—	—	—	864	864
NDT fund investments subtotal[d][e]	5,828	2,630	423	5,414	14,295	7,251	3,205	464	5,255	16,175
Rabbi trust investments										
Cash equivalents	1	—	—	—	1	3	—	—	—	3
Mutual funds	39	—	—	—	39	36	—	—	—	36
Life insurance contracts	—	27	1	—	28	—	33	—	—	33
Rabbi trust investments subtotal	40	27	1	—	68	39	33	—	—	72
Investments in equities	6	—	—	—	6	43	—	—	—	43
Commodity derivative assets										
Economic hedges	3,505	11,353	5,585	—	20,443	3,017	7,223	3,899	—	14,139
Proprietary trading	—	4	6	—	10	—	19	8	—	27
Effect of netting and allocation of collateral[f][g]	(2,951)	(10,348)	(3,525)	—	(16,824)	(2,108)	(6,177)	(2769)	—	(11,054)
Commodity derivative assets subtotal	554	1,009	2,066	—	3,629	909	1,065	1,138	—	3,112
DPP consideration	—	515	—	—	515	—	365	—	—	365
Total assets	6,469	4,181	2,490	5,414	18,554	8,355	4,668	1,602	5,255	19,880
Liabilities										
Commodity derivative liabilities										
Economic hedges	(3,171)	(11,498)	(5,588)	—	(20,257)	(2,201)	(6,870)	(3,965)	—	(13,036)
Proprietary trading	—	(4)	(2)	—	(6)	—	(18)	(2)	—	(20)
Effect of netting and allocation of collateral[f][g]	3,279	10,700	3,743	—	17,722	2,189	6,642	2,735	—	11,566
Commodity derivative liabilities subtotal	108	(802)	(1,847)	—	(2,541)	(12)	(246)	(1,232)	—	(1,490)
Deferred compensation obligation	—	(57)	—	—	(57)	—	(43)	—	—	(43)
Total liabilities	108	(859)	(1,847)	—	(2,598)	(12)	(289)	(1,232)	—	(1,533)
Total net assets	$ 6,577	$ 3,322	$ 643	$ 5,414	$ 15,956	$ 8,343	$ 4,379	$ 370	$ 5,255	$ 18,347

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(a) CEG Parent has $49 million of Level 1 cash equivalents as of December 31, 2022. We exclude cash of $390 million and $417 million as of December 31, 2022 and December 31, 2021, respectively, and restricted cash of $70 million and $46 million as of December 31, 2022 and December 31, 2021, respectively. CEG Parent has excluded an additional $19 million of cash as of December 31, 2022.
(b) Includes $99 million and $116 million of cash received from outstanding repurchase agreements as of December 31, 2022 and 2021, respectively, 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 ($45) million and ($55) million as of December 31, 2022 and 2021, respectively, held in an investment vehicle primarily to hedge the equity option component of convertible debt.
(d) Includes net derivative assets of $1 million and net derivative liabilities of $1 million, which have total notional amounts of $494 million and $687 million as of December 31, 2022 and 2021, 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 $168 million and $111 million as of December 31, 2022 and 2021, respectively, which include certain derivative assets that have notional amounts of $59 million and $182 million as of December 31, 2022 and 2021, 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) Net collateral posted to counterparties totaled $328 million, $352 million, and $218 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2022. Net collateral posted to/(received from) 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.
(g) Includes $836 million and $897 million of variation margin held from the exchanges as of December 31, 2022 and 2021, respectively.

As of December 31, 2022, we have outstanding commitments to invest in private credit, private equity, and real estate investments of $235 million, $139 million, and $392 million, respectively. These commitments will be funded by our existing NDT funds.

We hold investments without readily determinable fair values with carrying amounts of $46 million and $33 million as of December 31, 2022 and 2021, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the years ended December 31, 2022 and 2021.

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, 2022 and 2021:

(Dollars in millions, unless otherwise noted)

	For the Year Ended December 31, 2022			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of January 1, 2022	$ 464	$ (94)	$ —	$ 370
Total realized / unrealized losses				
Included in net income	(2)	(753) (a)	(2)	(757)
Included in noncurrent payables to affiliates	(10)	—	—	(10)
Change in collateral	—	253	—	253
Impacts of separation	—	—	3	3
Purchases, sales, issuances and settlements				
Purchases	5	594	—	599
Sales	—	(50)	—	(50)
Settlements	(35)	(102)	—	(137)
Transfers into Level 3	2	381 (b)	—	383
Transfers out of Level 3	(1)	(10) (b)	—	(11)
Balance as of December 31, 2022	$ 423	$ 219	$ 1	$ 643
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities as of December 31, 2022	$ (2)	$ (1,265)	$ (2)	$ (1,269)

	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 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)

(a) Includes an addition of $410 million for realized losses due to the settlement of derivative contracts for both of the years ended December 31, 2022 and 2021, 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 (losses) gains included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2022, 2021, and 2020:

(Dollars in millions, unless otherwise noted)

	Operating Revenues			Purchased Power and Fuel			Other, net		
	2022	2021	2020	2022	2021	2020	2022	2021	2020
Total (losses) gains included in net income	$ (860)	$ (1,343)	$ (404)	$ 5	$ 531	$ (10)	$ (4)	$ 5	$ 2
Total unrealized (losses) gains	(1,330)	(1,577)	(31)	65	355	37	(2)	5	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 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, 2022. 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, 2022, 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 considers 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 consolidated 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 $72.43 and $4.57 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, 2022	Fair Value as of December 31, 2021	Valuation Technique	Unobservable Input	2022 Range & Arithmetic Average				2021 Range & Arithmetic Average			
Mark-to-market derivatives—Economic hedges[(a)(b)]	$ (3)	$ (66)	Discounted Cash Flow	Forward power price	$0.63	-	$283	$72	$8.86	-	$481	$55
				Forward gas price	$1.67	-	$26	$4.57	$1.69	-	$17	$3.50
			Option Model	Volatility percentage	97%	-	119%	111%	24%	-	284%	56%

(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 posted (received) on level three positions of $218 million and ($34) million as of December 31, 2022 and December 31, 2021, 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, 2022, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2023	2024	2025	2026	2027	2028 and beyond
Letters of credit	$ 2,475	$ 2,465	$ 10	$ —	$ —	$ —	$ —
Surety bonds[(a)]	978	977	1	—	—	—	—
Total commercial commitments	$ 3,453	$ 3,442	$ 11	$ —	$ —	$ —	$ —

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

Prior Merger Commitment. Consistent with a 2012 MDPSC order approving a prior merger, certain commitments were made for the development of new generation in Maryland, 55 MW of which remains unsatisfied to date. In 2016, we terminated rights to a development project intended to satisfy the remaining commitment and recorded a pre-tax $50 million loss contingency within Operating and maintenance expense in our Consolidated Statements of Operations and Comprehensive Income, representing the potential liquidated damages payment due for the shortfall, consistent with the terms of the original MDPSC order. In September 2022, a previously executed PPA with a third party became effective upon satisfaction of all conditions precedent (including an extension of time to complete the merger commitment from the MDPSC) and will result in the construction of a wind farm project with an expected commercial operation date (“COD”) of December 31, 2024. The satisfaction of the conditions precedent to the PPA, coupled with the milestones contained in the PPA to ensure the facility is constructed, demonstrate that the merger commitment is likely to be met through support of a PPA enabling the project to be constructed rather than a liquidated damages payment. As a result, we have reversed the previously recognized loss contingency and recorded a pre-tax gain of $50 million within Operating and maintenance expense in our Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2022.

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, 2022, the current liability limit per incident is $13.7 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 $13.2 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 $13.7 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 Calvert Cliffs, Ginna, and Nine Mile Point nuclear generating units or their operations.

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 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 $30 million for 2022, and was $114 million and $75 million for 2021 and 2020, 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 $252 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 consolidated 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.

(Dollars in millions, unless otherwise noted)

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 are in the process of extending the agreements for Calvert Cliffs, Ginna, Nine Mile Point, and Fitzpatrick to provide for the reimbursement of SNF storage costs through December 31, 2025.

Under the settlement agreements, we received total cumulative cash reimbursements of $1,731 million through December 31, 2022 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 $1,501 million. As of December 31, 2022 and 2021, 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, 2022	December 31, 2021
DOE receivable - current[(a)]	$ 125	$ 241
DOE receivable - noncurrent[(b)]	130	85
Amounts owed to co-owners[(c)]	(12)	(35)

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(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, 2022 and 2021:

	December 31, 2022	December 31, 2021
Former ComEd units[(a)]	$ 1,100	$ 1,083
Fitzpatrick[(b)]	130	127
Total SNF Obligation	$ 1,230	$ 1,210

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(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, 2022 was 4.169% for the deferred amount transferred from ComEd and 3.415% for the deferred FitzPatrick amount.

The following table summarizes sites for which we do not have an outstanding SNF Obligation:

(Dollars in millions, unless otherwise noted)

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 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. In addition, we are currently involved in 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 consolidated financial statements.

As of December 31, 2022 and 2021, we had accrued undiscounted amounts for environmental liabilities of $119 million and $120 million, respectively, in Accrued expenses and Other deferred credits and other liabilities in the Consolidated Balance Sheets.

Cotter Corporation. The EPA has advised Cotter Corporation (N.S.L.) (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at two sites 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 from these two Missouri superfund sites, West Lake Landfill and Latty Avenue. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to us, and ultimately retained by us per the terms of our separation from Exelon. Refer to Note 1 — Basis of Presentation for additional information on the separation.

West Lake Landfill. Including Cotter, there are three PRPs currently participating in the West Lake Landfill remediation proceeding.

In September 2018, the EPA issued its Record of Decision Amendment (RODA) for the selection of a final remedy that requires partial excavation of the radiological materials and capping the landfill. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed in the middle of 2024. In March 2019, the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. The total estimated cost of the remedy, considering the current EPA technical requirements, is approximately $295 million, including cost escalation on an undiscounted basis. Our investigation has identified several other parties who also may be PRPs and could be liable to contribute to the final remedy. We have determined that a loss associated with the EPA's partial excavation and 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 consolidated financial statements.

In September 2018, the three identified PRPs, including Cotter, signed 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 $50 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 consolidated financial statements.

Latty Avenue. 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. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. On August 3, 2020, the DOJ advised Cotter that it is seeking approximately $90 million from all the PRPs. In December 2021, a good faith offer was submitted to the government. After subsequent communications with DOJ, Cotter proposed, and DOJ agreed to consider mediation to facilitate a settlement. Pursuant to a series of agreements since 2011, the DOJ and Cotter have extended the Statute of Limitations through August 31, 2023. We have determined that a loss associated with this matter is probable and have recorded an estimated liability, included in the total amount as discussed above, that reflects management's best estimate of Cotter's allocable share of the cost. It is reasonably possible that Cotter's allocable share could differ significantly, which could have a material impact on our consolidated financial statements.

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, PECO, or BGE. 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, 2022 and 2021, we recorded estimated liabilities of approximately $95 million and $81 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2022, approximately $23 million of this amount related to 253 open claims presented to us, while the remaining $72 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 are now defendants in approximately 150 lawsuits in the MDL brought by several hundred plaintiffs and more than 130 insurance companies.

Defendants filed Motions to Dismiss the amended complaints in five bellwether cases in July 2022. Briefing was completed in September 2022, and oral argument was held on October 11 and 12, 2022. On February 3, 2023, the court granted the motions to dismiss in part and denied them in part. As a result, we remain a defendant in the lawsuits. On June 27, 2022, a new group of 24 plaintiff customers filed a petition in Starr County seeking damages and redress for property damage and other injury. One plaintiff household was a customer of Constellation NewEnergy, Inc. as the Retail Electricity Provider (REP). This is the first time that Constellation has been named in a winter storm lawsuit as a REP. 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. 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. On May 25, 2022, a settlement was approved by the MPSC. In connection with the settlement, the liability was revised to $11 million as of June 30, 2022, and was paid in the third quarter of 2022. On June 14, 2022, the lawsuit in Missouri federal court was dismissed.

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

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. Our LTIP authorized 20,000,000 shares of common stock for these awards. 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. The impact of this modification was not material to our stock-based compensation expense for the year ended December 31, 2022.

Our employees were granted stock-based awards through the Exelon LTIP prior to separation, which primarily included performance share awards, restricted stock units, and stock options. We also granted cash awards. Performance share awards were 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 have resulted in cash settlement of the entire award.

The following table presents the stock-based compensation expense included in the Consolidated Statements of Operations and Comprehensive Income. The information does not include expenses related to the cash awards as they are not considered stock-based compensation plans under the applicable authoritative guidance:

(Dollars in millions, unless otherwise noted)

	Year Ended December 31,		
	2022[(a)]	2021[(b)]	2020[(b)]
Total stock-based compensation expense included in operating and maintenance expense	$ 116	$ 47	$ 27
Income tax benefit	(29)	(12)	(7)
Total after-tax stock-based compensation expense	$ 87	$ 35	$ 20

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(a) Costs recognized for the year ended December 31, 2022 are related to the Constellation LTIP.
(b) Costs recognized for the years ended December 31, 2021 and 2020 were allocated to us by Exelon under the Exelon LTIP prior to separation.

We receive a tax deduction based on the intrinsic value of the award on the distribution date for restricted stock units. The tax deduction related to performance share awards was not material for the year ended December 31, 2022. For each award, throughout the requisite service period, we recognize the tax benefit related to compensation costs. The following table presents information regarding our realized tax benefit when distributed:

	December 31, 2022
Restricted stock units	$ 2

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards are typically settled 50% in common stock and 50% in cash at the end of the three-year performance period, subject to certain ownership thresholds that, if met, may result in cash settlement of the entire award.

The common stock portion of the performance share awards is considered an equity award and is valued based on our stock price on the grant date. The cash portion of the performance share awards is considered a liability award which is remeasured each reporting period based on the current stock price. As the value of the common stock and cash portions of the awards are based on the stock price during the performance period, coupled with changes in the total expected payout of the award, the compensation costs are subject to volatility until payout is established.

For nonretirement-eligible employees, performance share awards are recognized over the vesting period of three years using the straight-line method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant. We process forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes our nonvested performance share awards activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2021	—	$ —
Granted	1,575,542	48.33
Change in performance	728,054	47.30
Forfeited	(22,617)	48.55
Undistributed vested awards[(a)]	(1,431,637)	48.35
Nonvested at December 31, 2022	849,342	$ 47.40

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(a) Includes 1,272,921 of performance share awards that vested but were not distributed to retirement-eligible employees during 2022.

The following table summarizes the weighted average grant date fair value and the total fair value of performance share awards vested:

(Dollars in millions, unless otherwise noted)

	December 31, 2022[a]
Weighted average grant date fair value (per share)	$ 48.33
Total fair value of performance shares vested	69

(a) As of December 31, 2022, $28 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.7 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized ratably over the first six months in the year of grant if the employee reaches retirement eligibility prior to July 1st of the grant year or through the date of which the employee reaches retirement eligibility. We process forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes our nonvested restricted stock unit activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2021	—	$ —
Granted	1,497,651	54.17
Vested	(144,903)	49.82
Forfeited	(62,238)	59.47
Undistributed vested awards[a]	(499,842)	55.16
Nonvested at December 31, 2022	790,668	$ 53.72

(a) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2022.

The following table summarizes the weighted average grant date fair value and the total fair value of restricted stock units vested:

	December 31, 2022[a]
Weighted average grant date fair value (per share)	$ 54.17
Total fair value of performance shares vested	35

(a) As of December 31, 2022, $27 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.0 years.

21. Changes in Accumulated Other Comprehensive Income

The following tables present changes in AOCI, net of tax, by component:

(Dollars in millions, unless otherwise noted)

	Losses on Cash Flow Hedges		Pension and Non-Pension Postretirement Benefit Plan Items[a]		Foreign Currency Items		Total	
Balance at December 31, 2019	$	(5)	$	—	$	(27)	$	(32)
OCI before reclassifications		(2)		—		4		2
Net current-period OCI		(2)		—		4		2
Balance at December 30, 2020	$	(7)	$	—	$	(23)	$	(30)
OCI before reclassifications		(1)		—		—		(1)
Net current-period OCI		(1)		—		—		(1)
Balance at December 30, 2021	$	(8)	$	—	$	(23)	$	(31)
Separation-related adjustments		—		(2,006)		—		(2,006)
OCI before reclassifications		(1)		186		(3)		182
Amounts reclassified from AOCI		—		95		—		95
Net current-period OCI		(1)		(1,725)		(3)		(1,729)
Balance at December 30, 2022	$	(9)	$	(1,725)	$	(26)	$	(1,760)

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(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 15 — Retirement Benefits for additional information. See our Statements of Operations and Comprehensive Income for individual components of AOCI.

The following table presents income tax (expense) benefit allocated to each component of our other comprehensive income (loss):

	Year Ended December 31,					
	2022		2021		2020	
Pension and non-pension postretirement benefit plans:						
Actuarial loss reclassified to periodic benefit cost	$	(33)	$	—	$	—
Pension and non-pension postretirement benefit plans valuation adjustment[a]		619		—		—

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(a) Includes $680 million of income tax benefit related to the separation adjustment for the year ended December 31, 2022.

22. Variable Interest Entities

As of December 31, 2022 and 2021, 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.

(Dollars in millions, unless otherwise noted)

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, 2022 and 2021. 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.

	December 31, 2022	December 31, 2021
Cash and cash equivalents	$ 51	$ 35
Restricted cash and cash equivalents	46	48
Accounts receivable		
Customer	20	24
Other	9	6
Inventories, net		
Materials and supplies	12	14
Other current assets	549	405
Total current assets	687	532
Property, plant and equipment, net	1,965	2,027
Other noncurrent assets	190	215
Total noncurrent assets	2,155	2,242
Total assets[(a)]	$ 2,842	$ 2,774
Long-term debt due within one year	$ 60	$ 70
Accounts payable	17	10
Accrued expenses	23	21
Other current liabilities	2	1
Total current liabilities	102	102
Long-term debt	764	822
Asset retirement obligations	173	151
Other noncurrent liabilities	3	3
Total noncurrent liabilities	940	976
Total liabilities[(b)]	$ 1,042	$ 1,078

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(a) Our balances include unrestricted assets for current unamortized energy contract assets of $23 million and $23 million, disclosed within other current assets in the table above and noncurrent unamortized energy contract assets of $178 million and $202 million, disclosed within other noncurrent assets in the table above as of December 31, 2022 and 2021, respectively.

(b) Our balances include liabilities with recourse of $1 million and $1 million as of December 31, 2022 and 2021, respectively.

(Dollars in millions, unless otherwise noted)

As of December 31, 2022 and 2021, our consolidated VIEs included the following:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason we are the primary beneficiary:
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.	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.
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.

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, 2022 and 2021, 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, 2022			December 31, 2021		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 715	$ —	$ 715	$ 772	$ 372	$ 1,144
Total liabilities[a]	54	—	54	80	216	296
Our ownership interest in VIE[a]	—	—	—	—	139	139
Other ownership interests in VIE[a]	661	—	661	692	17	709

(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, 2022 and 2021.

As of December 31, 2022 and 2021, 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. We have a 90% equity ownership in a distributed energy company. We sold this investment in the fourth quarter of 2022 resulting in it no longer being classified as an unconsolidated VIE.	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.

23. 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,		
	2022	2021	2020
Gross receipts[(a)]	$ 130	$ 99	$ 99
Property	274	268	265
Payroll	130	109	113

(a) Represent gross receipts taxes related to our retail operations. The offsetting collection of gross receipts taxes from customers is recorded in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

	Other, net		
	For the Years Ended December 31,		
	2022	2021	2020
Decommissioning-related activities:			
Net realized income on NDT funds[a]			
Regulatory Agreement Units	$ 333	$ 817	$ 185
Non-Regulatory Agreement Units	97	449	160
Net unrealized (losses) gains on NDT funds			
Regulatory Agreement Units	(1,354)	351	724
Non-Regulatory Agreement Units	(798)	209	391
Regulatory offset to NDT fund-related activities[b]	820	(917)	(729)
Decommissioning-related activities	(902)	909	731
Investment income	58	—	—
Non-service net periodic benefit credit[c]	110	—	—
Net realized and unrealized (losses) gains from equity investments[d]	(13)	(160)	186
Return to provision adjustment[e]	(49)	—	—

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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 and the elimination of income taxes related to all NDT fund activity 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. 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) Historically, we were allocated our portion of pension and OPEB non-service credits (costs) from Exelon, which was included in Operating and maintenance expense. Effective February 1, 2022, the non-service credit (cost) components will now be included in Other, net, in accordance with single employer plan accounting. See Note 15 — Retirement Benefits for additional information.
(d) For 2022, represents Net realized and unrealized (losses) gains from equity investments. For 2021 and 2020, represents Net unrealized (losses) gains from equity investments.
(e) This reflects amounts contractually owed to Exelon under the tax matters agreement, which is offset in Income taxes. See Note 14 — Income Taxes for additional information.

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,		
	2022	2021	2020
Property, plant, and equipment[a]	$ 1,065	$ 2,954	$ 2,070
Amortization of intangible assets, net[a]	26	49	53
Amortization of energy contract assets and liabilities[b]	35	31	30
Nuclear fuel[c]	758	992	983
ARO accretion[d]	543	514	500
Total depreciation, amortization, and accretion	$ 2,427	$ 4,540	$ 3,636

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(a) Included in Depreciation and amortization expense in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

(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.

	Cash paid during the year		
	For the Years Ended December 31,		
	2022	2021	2020
Interest (net of amount capitalized)	$ 230	$ 275	$ 331
Income taxes (net of refunds)	287	426	70

	Other non-cash operating activities					
	CEG Parent			Constellation		
	For the Years Ended December 31,			For the Years Ended December 31,		
	2022	2021	2020	2022	2021	2020
Pension and non-pension postretirement benefit costs	$ 17	$ 123	$ 115	$ 17	$ 123	$ 115
Other decommissioning-related activity[(a)]	(263)	(946)	(659)	(263)	(946)	(659)
Energy-related options[(b)]	293	125	104	293	125	104
Severance costs	(1)	(73)	90	(1)	(73)	90
Long-term incentive plan	44	—	—	—	—	—
Provision for excess and obsolete inventory	(12)	(13)	128	(12)	(13)	128
Amortization of operating ROU asset	75	119	155	75	119	155
Loss on sale of receivables	69	36	30	69	36	30
Fair value adjustments related to gas imbalances	37	—	—	37	—	—
Prior merger commitment[(c)]	(50)	—	—	(50)	—	—

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(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 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.
(c) Reversal of a charge related to a prior 2012 merger commitment. See Note 19 - Commitments and Contingencies for additional information.

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, 2022	CEG Parent	Constellation
Cash and cash equivalents	$ 422	$ 403
Restricted cash and cash equivalents	106	98
Total cash, restricted cash, and cash equivalents	$ 528	$ 501

(Dollars in millions, unless otherwise noted)

December 31, 2021	CEG Parent	Constellation
Cash and cash equivalents	$ 504	$ 504
Restricted cash and cash equivalents	72	72
Total cash, restricted cash, and cash equivalents	$ 576	$ 576

December 31, 2020	CEG Parent	Constellation
Cash and cash equivalents	$ 226	$ 226
Restricted cash and cash equivalents	89	89
Cash, restricted cash, and cash equivalents - Held for Sale	12	12
Total cash, restricted cash, and cash equivalents	$ 327	$ 327

December 31, 2019	CEG Parent	Constellation
Cash and cash equivalents	$ 303	$ 303
Restricted cash and cash equivalents	146	146
Total cash, restricted cash, and cash equivalents	$ 449	$ 449

For additional information on restricted cash, see Note 1 — Basis of Presentation.

Supplemental Balance Sheet Information

The following tables provide additional information about material items recorded in the Consolidated Balance Sheets.

	Investments	
	December 31, 2022	December 31, 2021
Equity method investments	$ 82	$ 62
Other investments:		
Employee benefit trusts and investments[(a)]	68	72
Equity investments without readily determinable fair values	46	33
Other available for sale debt security investments	6	7
Total investments	$ 202	$ 174

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(a) Debt and equity security investments are recorded at fair market value.

	Accrued expenses	
December 31, 2022	CEG Parent	Constellation
Compensation-related accruals[(a)]	$ 540	$ 502
Taxes accrued	257	257

	Accrued expenses	
December 31, 2021	CEG Parent	Constellation
Compensation-related accruals[(a)]	$ 356	$ 356
Taxes accrued	272	272

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(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.

(Dollars in millions, unless otherwise noted)

24. 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,		
	2022[(a)]	2021	2020
ComEd[(b)]	$ 58	$ 376	$ 330
PECO[(c)]	33	196	190
BGE[(d)]	18	236	315
PHI	51	366	367
Pepco[(e)]	39	270	279
DPL[(f)]	10	79	75
ACE[(g)]	2	17	13
Other	—	14	9
Total operating revenues from affiliates	$ 160	$ 1,188	$ 1,211

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(a) Represents only January 2022 costs prior to separation on February 1, 2022.
(b) 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.
(c) 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.
(d) We provide a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.
(e) We provide electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
(f) We provide a portion of DPL's energy requirements under its MDPSC and DEPSC approved market-based SOS commodity programs.
(g) 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 were directly charged or allocated to us. Certain of these services will continue after the separation and are covered by the TSA. See Note 1 — Basis of Presentation 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,		
2022[(a)]	2021	2020	2022[(a)]	2021	2020
$ 44	$ 588	$ 552	$ 15	$ 129	$ 54

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(a) Represents only January 2022 costs prior to separation on February 1, 2022.

(Dollars in millions, unless otherwise noted)

Current Receivables from/Payables to affiliates

The following table presents Current receivables from affiliates and Current payables to affiliates:

	December 31, 2021	
	Receivables from affiliates:	Payables to affiliates:
ComEd	$ 84	$ 13
PECO	30	—
BGE	4	—
Pepco	20	—
DPL	4	—
ACE	7	—
BSC	—	102
Other	11	16
Total(a)	$ 160	$ 131

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(a) Prior to the completion of the separation on February 1, 2022, we engaged in transactions with affiliates of Exelon in the normal course of business. As of December 31, 2022, all transactions with Exelon or its affiliates are third-party transactions.

Payables Related to Regulatory Agreement Units

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.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During the fourth quarter of 2022, 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 or submit with the SEC. These disclosure controls and procedures have been designed to ensure that (a) information relating to our consolidated subsidiaries, 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, 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, 2022, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Changes in Internal Control Over Financial Reporting

We continually strive to improve our disclosure controls and procedures to enhance the quality of our financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2022 that have materially affected, or are reasonably likely to materially affect, any of our internal control over financial reporting.

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, 2022. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2022 and, therefore, concluded that our 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 16, 2023

Name	Age	Position	Period
Dominguez, Joseph	60	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	47	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	52	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.	57	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.	56	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	51	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	50	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	46	Senior Vice President and Controller	2022 - Present
		Vice President and Controller, Exelon Generation Company, LLC	2016 - 2022

Directors, Director Nomination Process and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)), and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in our definitive 2023 proxy statement (2023 Constellation Proxy Statement) to be filed with the SEC on or before April 30, 2023 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Conduct and Ethics

In connection with the completion of the separation from Exelon, our Board of Directors adopted a code of conduct and ethics (the “Code of Ethics”), effective February 1, 2022, 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 provisions of our Code of Ethics that apply to, or grant a waiver from a provision of our Code of Ethics for any executive officer, we will publicly disclose such amendment or waiver on our website and as required by applicable law or regulation. The information contained on, or accessible from, our website is not part of this annual report by reference or otherwise.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under "Executive Compensation Data" and "Report of the Compensation Committee" in the Constellation Proxy Statement for the 2023 Annual Meeting of Shareholders which is incorporated herein by reference.

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

The information required by this item will be set forth under "Ownership of Constellation Stock" in the Constellation Proxy Statement for the 2023 Annual Meeting of Shareholders which is incorporated herein by reference.

Securities Authorized for Issuance under Constellation Equity Compensation Plans

	[A] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[B] Weighted-average price of outstanding Options, warrants and rights	[C] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [A]) (Note 2)
Equity compensation plans approved by security holders	$ 2,984,589	N/A	$ 37,533,641

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(1) Balance includes outstanding performance shares and restricted stock units that were granted under the Constellation LTIP (including shares awarded under those plans and deferred into the stock deferral plan) and deferred stock units granted to directors as part of their compensation. Unvested performance shares are subject to performance metrics and to a CFO/Debt modifier. In addition, pursuant to the terms of the Constellation LTIP plan, 50% of final payouts are made in the form of shares of common stock and 50% is made in form of in cash, or if the participant has exceeded 200% of their stock ownership requirement, 100% of the final payout is made in cash. For performance shares, the total includes the maximum number of shares that could be issued assuming all participants receive 50% of payouts in shares and assuming the performance and CFO/Debt modifier metrics were both at maximum, representing best case performance, for a total of 1,552,925 shares. If the performance and total shareholder return modifier metrics were at "target", the number of securities to be issued for such awards would be 776,463. The balance also includes 127,664 shares to be issued upon the conversion of deferred stock units awarded to members of the Constellation board of directors. Conversion of the deferred stock units to shares of common stock occurs after a director terminates service on the Constellation board.

(2) Includes 17,638,730 shares remaining available for issuance from the employee stock purchase plan and 19,894,911 shares remaining available for issuance to former Constellation employees with outstanding awards made under the prior Constellation LTIP.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under "Related Persons Transactions" and "Director Independence" in the Constellation Proxy Statement for the 2023 Annual Meeting of Shareholders which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under "The Ratification of PricewaterhouseCoopers LLP as Constellation's Independent Registered Public Accounting Firm for 2023" in the Constellation Proxy Statement for the 2023 Annual Meeting of Shareholders which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

(1) Constellation Energy Corporation and Subsidiary Companies

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 16, 2023 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2022, 2021, and 2020

Consolidated Statements of Cash Flows for the Years Ended December 31, 2022, 2021, and 2020

Consolidated Balance Sheets at December 31, 2022 and 2021

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2022, 2021, and 2020

Combined Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2022, 2021, and 2020

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 Corporation and Subsidiary Companies

Constellation Energy Generation, LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions and adjustments: Charged to Costs and Expenses	Additions and adjustments: Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2022					
Allowance for credit losses	$ 59	$ 10	$ —	$ 18 [(a)]	$ 51
Deferred tax valuation allowance	22	—	(11)	—	11
Reserve for obsolete materials	250	11	(6)	17	238
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)	$ 5 [(a)]	$ 32
Deferred tax valuation allowance	24	—	(1)	—	23
Reserve for obsolete materials	143	123 [(b)]	(1)	—	265

(a) Write-offs, net of recoveries of individual accounts receivable.
(b) 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 Combined Notes to Consolidated Financial Statements for additional information.

(2) Constellation Energy Generation, LLC and Subsidiary Companies

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 16, 2023 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2022, 2021, and 2020

Consolidated Statements of Cash Flows for the Years Ended December 31, 2022, 2021, and 2020

Consolidated Balance Sheets at December 31, 2022 and 2021

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2022, 2021, and 2020

Combined Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2022, 2021, and 2020 [(a)]

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

(a) The Constellation Energy Generation, LLC Schedule II - Valuation and Qualifying Accounts for Years ended December 31, 2022, 2021, and 2020 is the same as the Constellation Energy Corporation Schedule II.

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 SEC 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	Second Amended and Restated Bylaws of Constellation Energy Corporation, effective July 26, 2022 (File No. 001-41137, Form 8-K dated July 29, 2022, Exhibit 3.1)
3-3	Amended and Restated Certificate of Organization, as amended, of Constellation (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 3.3)
3-4	Amended and Restated Operating Agreement of Constellation (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 3.4)
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 (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 4.11)
4-12	First Supplemental Indenture, dated as of February 9, 2022, between Constellation and Deutsche Bank Trust Company Americas, as trustee (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 4.12)

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 (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 4.14)
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 (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 4.15)
4-16	Amended and Restated Declaration of Trust of Fells Point Funding Trust, dated as of February 9, 2022 (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 4.16)
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 (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 4.17)
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 (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.10)

10-11	Constellation Energy Corporation Non-Employee Deferred Stock Unit Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.11)
10-12	Constellation Energy Corporation Unfunded Deferred Compensation Plan for Directors (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.12)
10-13	Constellation Energy Group Deferred Compensation Plan for Non-Employee Directors (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.13)
10-14*	Constellation Energy Corporation Senior Management Severance Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.14)
10-15*	Constellation Energy Corporation Deferred Compensation Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.15)
10-16*	Constellation Energy Corporation Supplemental Management Retirement Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.16)
10-17	Constellation Energy Corporation PECO Supplemental Pension Benefit Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.17)
10-18*	Constellation Energy Group Nonqualified Deferred Compensation Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.18)
10-19	Constellation Energy Group Benefits Restoration Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.19)
10-20	Constellation Energy Corporation Supplemental Pension Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.20)
10-21*	Constellation Energy Corporation Long-Term Incentive Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.21)
10-22	Constellation Energy Corporation Employee Stock Purchase Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.22)
10-23*	Form of Restricted Stock Unit Retention Award under the Constellation Energy Corporation Long-Term Incentive Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.23)
10-24*	Form of Restricted Stock Unit Award under the Constellation Energy Corporation Long-Term Incentive Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.24)
10-25*	Form of Performance Share Award under the Constellation Energy Corporation Long-Term Incentive Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.25)
10-26*	Form of Separation Agreement under the Constellation Energy Corporation Senior Management Severance Plan (File No. 001-41137, Form 10-K dated February 25, 2022, Exhibit 10.26)
10-27	Amendment No. 3 to Receivables Purchase Agreement, dated as of August 16, 2022, 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. 001-41137, Form 8-K, dated August 18, 2022, Exhibit 10.1).
	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	Nneka Rimmer
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, 2022 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, 2022 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)

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* Management contract or compensatory plan or arrangement.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Baltimore and State of Maryland on the 16th day of February, 2023.

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 16th day of February, 2023.

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	**Ashish Khandpur**
Yves C. de Balmann	**Robert Lawless**
Bradley Halverson	**John Richardson**
Charles Harrington	**Nneka Rimmer**
Julie Holzrichter	

By:	/s/ DAVID DARDIS	February 16, 2023
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 16th day of February, 2023.

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 16th day of February, 2023.

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)