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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 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

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 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 is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The number of shares outstanding of each registrant’s common stock as of September 30, 2022 was as follows:

Constellation Energy Corporation Common Stock, without par value	327,017,895
Constellation Energy Generation, LLC	Not applicable

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GLOSSARY OF TERMS AND ABBREVIATIONS

Constellation Energy Corporation and Related Entities

CEG Parent	Constellation Energy Corporation
Constellation	Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC)
Registrants	CEG Parent and Constellation, collectively
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 Postretirement Benefit Obligation
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
Brookfield Renewable	Brookfield Renewable Partners, L.P.
CES	Clean Energy Standard
CODM	Chief Operating Decision Maker
Clean Energy Law	Illinois Public Act 102-0062 signed into law on September 15, 2021
CMC	Carbon Mitigation Credit
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
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
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
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
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
LIBOR	London Interbank Offered Rate
LTIP	Long-Term Incentive Plan
MDPSC	Maryland Public Service Commission
MISO	Midcontinent Independent System Operator, Inc.
MPSC	Missouri Public Service Commission
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation

NGX	Natural Gas Exchange, Inc.
Non-Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NPNS	Normal Purchase Normal Sale scope exception
NRC	Nuclear Regulatory Commission
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PBO	Projected Benefit Obligation
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
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
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
RMC	Risk Management Committee
RNF	Revenue Net of Purchased Power and Fuel Expense
ROU	Right-of-use
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation
SNF	Spent Nuclear Fuel
SOA	Society of Actuaries
SOFR	Secured Overnight Financing Rate
SOS	Standard Offer Service
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VEBA	Voluntary Employees' Beneficiary Associations
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

FILING FORMAT

This combined Form 10-Q 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. Neither Registrant makes any representation as to information relating to the other Registrant.

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, as well as the items discussed in (1) the Registrants' combined 2021 Annual Report on Form 10-K 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, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 19, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, ITEM 1A. Risk Factors, (b) Part I, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1. Financial Statements: Note 15, Commitments and Contingencies; and (3) 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. Neither 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. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

(In millions, except per share data)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Operating revenues				
Operating revenues	$ 6,051	$ 4,082	$ 16,947	$ 13,245
Operating revenues from affiliates	—	324	160	872
Total operating revenues	6,051	4,406	17,107	14,117
Operating expenses				
Purchased power and fuel	4,695	1,542	11,749	8,103
Purchased power and fuel from affiliates	—	4	5	—
Operating and maintenance	989	761	3,422	2,955
Operating and maintenance from affiliates	—	177	44	458
Depreciation and amortization	262	866	818	2,735
Taxes other than income taxes	145	115	415	354
Total operating expenses	6,091	3,465	16,453	14,605
(Loss) gain on sales of assets and businesses	(1)	65	13	144
Operating (loss) income	(41)	1,006	667	(344)
Other income and (deductions)				
Interest expense, net	(75)	(73)	(186)	(214)
Interest expense to affiliates	—	(4)	(1)	(11)
Other, net	(196)	(115)	(1,169)	561
Total other income and (deductions)	(271)	(192)	(1,356)	336
(Loss) income before income taxes	(312)	814	(689)	(8)
Income taxes	(123)	177	(504)	108
Equity in losses of unconsolidated affiliates	(4)	(4)	(10)	(6)
Net (loss) income	(193)	633	(195)	(122)
Net (loss) income attributable to noncontrolling interests	(5)	26	(1)	125
Net (loss) income attributable to common shareholders	$ (188)	$ 607	$ (194)	$ (247)
Comprehensive (loss) income, net of income taxes				
Net (loss) income	$ (193)	$ 633	$ (195)	$ (122)
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(2)	—	(4)	—
Actuarial loss reclassified to periodic cost	28	—	73	—
Pension and non-pension postretirement benefit plan valuation adjustment	4	—	4	—
Unrealized loss on cash flow hedges	(1)	—	(1)	(1)
Unrealized loss on foreign currency translation	(6)	(4)	(4)	—
Other comprehensive income (loss), net of income taxes	23	(4)	68	(1)
Comprehensive (loss) income	(170)	629	(127)	(123)
Comprehensive (loss) income attributable to noncontrolling interests	(5)	26	(1)	125
Comprehensive (loss) income attributable to common shareholders	$ (165)	$ 603	$ (126)	$ (248)
Average shares of common stock outstanding:				
Basic	327	—	327	—
Assumed exercise and/or distributions of stock-based awards	1	—	1	—
Diluted	328	—	328	—
Earnings per average common share				
Basic	$ (0.57)	$ —	$ (0.59)	$ —
Diluted	$ (0.57)	$ —	$ (0.59)	$ —

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
(In millions)	2022	2021
Cash flows from operating activities		
Net loss	$ (195)	$ (122)
Adjustments to reconcile net loss to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,810	3,951
Asset impairments	—	537
Gain on sales of assets and businesses	(13)	(144)
Deferred income taxes and amortization of investment tax credits	(915)	(204)
Net fair value changes related to derivatives	544	(1,244)
Net realized and unrealized losses (gains) on NDT funds	1,032	(383)
Net unrealized loss on CTV investments	27	83
Other non-cash operating activities	304	(582)
Changes in assets and liabilities:		
Accounts receivable	(150)	(207)
Receivables from and payables to affiliates, net	20	82
Inventories	(166)	(29)
Accounts payable and accrued expenses	789	357
Option premiums paid, net	(163)	(186)
Collateral received, net	766	1,974
Income taxes	364	177
Pension and non-pension postretirement benefit contributions	(229)	(237)
Other assets and liabilities	(3,756)	(2,849)
Net cash flows provided by operating activities	69	974
Cash flows from investing activities		
Capital expenditures	(1,090)	(1,086)
Proceeds from NDT fund sales	3,034	5,766
Investment in NDT funds	(3,212)	(5,900)
Collection of DPP, net	3,095	3,052
Proceeds from sales of assets and businesses	41	802
Other investing activities	3	5
Net cash flows provided by investing activities	1,871	2,639
Cash flows from financing activities		
Change in short-term borrowings	(209)	(340)
Proceeds from short-term borrowings with maturities greater than 90 days	—	880
Repayments of short-term borrowings with maturities greater than 90 days	(1,180)	—
Issuance of long-term debt	9	152
Retirement of long-term debt	(1,143)	(89)
Retirement of long-term debt to affiliate	(258)	—
Changes in money pool with Exelon	—	(285)
Acquisition of CENG noncontrolling interest	—	(885)
Distributions to Exelon	—	(1,373)
Contribution from Exelon	1,750	64
Dividends paid on common stock	(139)	—
Other financing activities	(43)	(45)
Net cash flows used in financing activities	(1,213)	(1,921)
Increase in cash, restricted cash, and cash equivalents	727	1,692
Cash, restricted cash, and cash equivalents at beginning of period	576	327
Cash, restricted cash, and cash equivalents at end of period	$ 1,303	$ 2,019
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (17)	$ (77)
Increase in DPP	3,733	2,933
Increase in PP&E related to ARO update	342	550

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)		September 30, 2022		December 31, 2021
ASSETS				
Current assets				
Cash and cash equivalents	$	1,192	$	504
Restricted cash and cash equivalents		111		72
Accounts receivable				
Customer accounts receivable (net of allowance for credit losses of $55 as of September 30, 2022 and December 31, 2021)		1,819		1,669
Other accounts receivable (net of allowance for credit losses of $5 as of September 30, 2022 and December 31, 2021)		579		592
Mark-to-market derivative assets		2,557		2,169
Receivables from affiliates		—		160
Inventories, net				
Natural gas, oil and emission allowances		422		284
Materials and supplies		1,042		1,004
Renewable energy credits		524		520
Other		1,607		1,007
Total current assets		9,853		7,981
Property, plant, and equipment (net of accumulated depreciation and amortization of $16,574 and $15,873 as of September 30, 2022 and December 31, 2021, respectively)		19,705		19,612
Deferred debits and other assets				
Nuclear decommissioning trust funds		13,453		15,938
Investments		193		174
Mark-to-market derivative assets		1,252		949
Prepaid pension asset		—		1,683
Deferred income taxes		23		32
Other		2,137		1,717
Total deferred debits and other assets		17,058		20,493
Total assets[(a)]	$	46,616	$	48,086

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Corporation and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	September 30, 2022	December 31, 2021
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 693	$ 2,082
Long-term debt due within one year	181	1,220
Accounts payable	2,597	1,757
Accrued expenses	933	737
Payables to affiliates	—	131
Mark-to-market derivative liabilities	2,392	981
Renewable energy credit obligation	773	777
Other	318	311
Total current liabilities	7,887	7,996
Long-term debt	4,480	4,575
Long-term debt to affiliates	—	319
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,647	3,703
Asset retirement obligations	12,564	12,819
Pension obligations	636	—
Non-pension postretirement benefit obligations	861	847
Spent nuclear fuel obligation	1,219	1,210
Payables to affiliates	—	3,357
Payables related to Regulatory Agreement Units	2,658	—
Mark-to-market derivative liabilities	1,244	513
Other	1,251	1,133
Total deferred credits and other liabilities	23,080	23,582
Total liabilities[(a)]	35,447	36,472
Commitments and contingencies (Note 15)		
Shareholders' equity		
Predecessor Member's Equity[(b)]	—	11,250
Common stock (No par value, 1,000 shares authorized, 327 shares outstanding as of September 30, 2022)	13,255	—
Retained deficit	(483)	—
Accumulated other comprehensive loss, net	(1,969)	(31)
Total shareholders' equity	10,803	11,219
Noncontrolling interests	366	395
Total equity	11,169	11,614
Total liabilities and shareholders' equity	$ 46,616	$ 48,086

(a) Our consolidated assets include $3,133 million and $2,549 million at September 30, 2022 and December 31, 2021, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,049 million and $1,077 million at September 30, 2022 and December 31, 2021, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 18 — 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
(Unaudited)

	Nine Months Ended September 30, 2022						
	Shareholders' 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, 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) income from February 1, 2022 to March 31, 2022	—	—	(45)	—	5	—	(40)
Employee incentive plan activity from February 1, 2022 to March 31, 2022	35	9	—	—	—	—	9
Common stock dividends ($0.14/common share) from February 1, 2022 to March 31, 2022	—	—	(46)	—	—	—	(46)
Other comprehensive income, net of income taxes from February 1, 2022 to March 31, 2022	—	—	—	21	—	—	21
Balance, March 31, 2022	326,699	$ 13,212	$ (91)	$ (2,016)	$ 400	$ —	$ 11,505
Net loss	—	—	(111)	—	(2)	—	(113)
Employee incentive plans	146	29	—	—	—	—	29
Changes in equity of noncontrolling interests	—	—	—	—	(9)	—	(9)
Common stock dividends ($0.14/common share)	—	—	(47)	—	—	—	(47)
Other comprehensive income, net of income taxes	—	—	—	24	—	—	24
Balance, June 30, 2022	326,845	$ 13,241	$ (249)	$ (1,992)	$ 389	$ —	$ 11,389
Net loss	—	—	(188)	—	(5)	—	(193)
Employee incentive plans	173	14	—	—	—	—	14
Changes in equity of non-controlling interest	—	—	—	—	(18)	—	(18)
Common stock dividends ($0.14/common share)	—	—	(46)	—	—	—	(46)
Other comprehensive income, net of income taxes	—	—	—	23		—	23
Balance, September 30, 2022	327,018	$ 13,255	$ (483)	$ (1,969)	$ 366	$ —	$ 11,169

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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

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

	Nine Months Ended September 30, 2021				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2020	$ 9,624	$ 2,805	$ (30)	$ 2,277	$ 14,676
Net (loss) income	—	(793)	—	24	(769)
Changes in equity of noncontrolling interests	—	—	—	(10)	(10)
Distributions to member	—	(458)	—	—	(458)
Other comprehensive income, net of income taxes	—	—	1	—	1
Balance, March 31, 2021	$ 9,624	$ 1,554	$ (29)	$ 2,291	$ 13,440
Net (loss) income	—	(61)	—	74	13
Changes in equity of noncontrolling interests	—	—	—	(12)	(12)
Distribution to member	—	(458)	—	—	(458)
Other comprehensive income, net of income taxes	—	—	2	—	2
Balance, June 30, 2021	$ 9,624	$ 1,035	$ (27)	$ 2,353	$ 12,985
Net income	—	607	—	26	633
Changes in equity of noncontrolling interest	—	—	—	(13)	(13)
Acquisition of CENG noncontrolling interest	1,080	—	—	(1,965)	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	(288)	—	—	—	(288)
Contribution from member	64	—	—	—	64
Distributions to member	—	(457)	—	—	(457)
Other comprehensive loss, net of income taxes	—	—	(4)	—	(4)
Balance, September 30, 2021	$ 10,480	$ 1,185	$ (31)	$ 401	$ 12,035

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Operating revenues				
Operating revenues	$ 6,051	$ 4,082	$ 16,947	$ 13,245
Operating revenues from affiliates	—	324	160	872
Total operating revenues	6,051	4,406	17,107	14,117
Operating expenses				
Purchased power and fuel	4,695	1,542	11,749	8,103
Purchased power and fuel from affiliates	—	4	5	—
Operating and maintenance	989	761	3,422	2,955
Operating and maintenance from affiliates	—	177	44	458
Depreciation and amortization	262	866	818	2,735
Taxes other than income taxes	145	115	415	354
Total operating expenses	6,091	3,465	16,453	14,605
(Loss) gain on sales of assets and businesses	(1)	65	13	144
Operating (loss) income	(41)	1,006	667	(344)
Other income and (deductions)				
Interest expense, net	(75)	(73)	(186)	(214)
Interest expense to affiliates	—	(4)	(1)	(11)
Other, net	(196)	(115)	(1,169)	561
Total other income and (deductions)	(271)	(192)	(1,356)	336
(Loss) income before income taxes	(312)	814	(689)	(8)
Income taxes	(123)	177	(504)	108
Equity in losses of unconsolidated affiliates	(4)	(4)	(10)	(6)
Net (loss) income	(193)	633	(195)	(122)
Net (loss) income attributable to noncontrolling interests	(5)	26	(1)	125
Net (loss) income attributable to membership interest	$ (188)	$ 607	$ (194)	$ (247)
Comprehensive (loss) income, net of income taxes				
Net (loss) income	$ (193)	$ 633	$ (195)	$ (122)
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(2)	—	(4)	—
Actuarial loss reclassified to periodic cost	28	—	73	—
Pension and non-pension postretirement benefit plan valuation adjustment	4	—	4	—
Unrealized loss on cash flow hedges	(1)	—	(1)	(1)
Unrealized loss on foreign currency translation	(6)	(4)	(4)	—
Other comprehensive income (loss), net of income taxes	23	(4)	68	(1)
Comprehensive (loss) income	(170)	629	(127)	(123)
Comprehensive (loss) income attributable to noncontrolling interests	(5)	26	(1)	125
Comprehensive (loss) income attributable to membership interests	$ (165)	$ 603	$ (126)	$ (248)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2022	2021
Cash flows from operating activities		
Net loss	$ (195)	$ (122)
Adjustments to reconcile net loss to net cash flows (used in) provided by operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,810	3,951
Asset impairments	—	537
Gain on sales of assets and businesses	(13)	(144)
Deferred income taxes and amortization of investment tax credits	(915)	(204)
Net fair value changes related to derivatives	544	(1,244)
Net realized and unrealized losses (gains) on NDT funds	1,032	(383)
Net unrealized losses on CTV investments	27	83
Other non-cash operating activities	265	(582)
Changes in assets and liabilities:		
Accounts receivable	(126)	(207)
Receivables from and payables to affiliates, net	62	82
Inventories	(166)	(29)
Accounts payable and accrued expenses	733	357
Option premiums paid, net	(163)	(186)
Collateral received, net	766	1,974
Income taxes	364	177
Pension and non-pension postretirement benefit contributions	(229)	(237)
Other assets and liabilities	(3,803)	(2,849)
Net cash flows (used in) provided by operating activities	(7)	974
Cash flows from investing activities		
Capital expenditures	(1,090)	(1,086)
Proceeds from NDT fund sales	3,034	5,766
Investment in NDT funds	(3,212)	(5,900)
Collection of DPP, net	3,095	3,052
Proceeds from sales of assets and businesses	41	802
Other investing activities	3	5
Net cash flows provided by investing activities	1,871	2,639
Cash flows from financing activities		
Changes in short-term borrowings	(209)	(340)
Proceeds from short-term borrowings with maturities greater than 90 days	—	880
Repayments of short-term borrowings with maturities greater than 90 days	(1,180)	—
Issuance of long-term debt	9	152
Retirement of long-term debt	(1,143)	(89)
Retirement of long-term debt to affiliate	(258)	—
Changes in money pool with Exelon	—	(285)
Acquisition of CENG noncontrolling interest	—	(885)
Distributions to member	(139)	(1,373)
Contribution from Exelon	1,750	64
Other financing activities	(56)	(45)
Net cash flows used in financing activities	(1,226)	(1,921)
Increase in cash, restricted cash, and cash equivalents	638	1,692
Cash, restricted cash, and cash equivalents at beginning of period	576	327
Cash, restricted cash, and cash equivalents at end of period	$ 1,214	$ 2,019
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (17)	$ (77)
Increase in DPP	3,733	2,933
Increase in PP&E related to ARO update	342	550

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	September 30, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,131	$ 504
Restricted cash and cash equivalents	83	72
Accounts receivable		
Customer accounts receivable (net of allowance for credit losses of $55 as of September 30, 2022 and December 31, 2021)	1,819	1,669
Other accounts receivable (net of allowance for credit losses of $5 as of September 30, 2022 and December 31, 2021)	555	592
Mark-to-market derivative assets	2,557	2,169
Receivables from affiliates	—	160
Inventories, net		
Natural gas, oil, and emission allowances	422	284
Materials and supplies	1,042	1,004
Renewable energy credits	524	520
Other	1,607	1,007
Total current assets	9,740	7,981
Property, plant, and equipment (net of accumulated depreciation and amortization of $16,574 and $15,873 as of September 30, 2022 and December 31, 2021, respectively)	19,705	19,612
Deferred debits and other assets		
Nuclear decommissioning trust funds	13,453	15,938
Investments	193	174
Mark-to-market derivative assets	1,252	949
Prepaid pension asset	—	1,683
Deferred income taxes	23	32
Other	2,137	1,717
Total deferred debits and other assets	17,058	20,493
Total assets[(a)]	$ 46,503	$ 48,086

See the Combined Notes to Consolidated Financial Statements

Constellation Energy Generation, LLC and Subsidiary Companies
Consolidated Balance Sheets
(Unaudited)

(In millions)	September 30, 2022	December 31, 2021
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 693	$ 2,082
Long-term debt due within one year	181	1,220
Accounts payable	2,553	1,757
Accrued expenses	898	737
Payables to affiliates	42	131
Mark-to-market derivative liabilities	2,392	981
Renewable energy credit obligation	773	777
Other	317	311
Total current liabilities	7,849	7,996
Long-term debt	4,480	4,575
Long-term debt to affiliates	—	319
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,647	3,703
Asset retirement obligations	12,564	12,819
Pension obligations	636	—
Non-pension postretirement benefit obligations	861	847
Spent nuclear fuel obligation	1,219	1,210
Payables to affiliates	—	3,357
Payables related to Regulatory Agreement Units	2,658	—
Mark-to-market derivative liabilities	1,244	513
Other	1,197	1,133
Total deferred credits and other liabilities	23,026	23,582
Total liabilities[(a)]	35,355	36,472
Commitments and contingencies (Note 15)		
Equity		
Member's equity		
Membership interest	12,326	10,482
Undistributed earnings	425	768
Accumulated other comprehensive loss, net	(1,969)	(31)
Total member's equity	10,782	11,219
Noncontrolling interests	366	395
Total equity	11,148	11,614
Total liabilities and equity	$ 46,503	$ 48,086

(a) Our consolidated assets include $3,133 million and $2,549 million as of September 30, 2022 and December 31, 2021, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $1,049 million and $1,077 million as of September 30, 2022 and December 31, 2021, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 18 — 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
(Unaudited)

	Nine Months Ended September 30, 2022				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2021	$ 10,482	$ 768	$ (31)	$ 395	$ 11,614
Net income	—	106	—	5	111
Separation-related adjustments	1,844	(11)	(2,006)	7	(166)
Changes in equity of noncontrolling interests	—	—	—	(7)	(7)
Distributions to member	—	(46)	—	—	(46)
Other comprehensive income, net of income taxes	—	—	21	—	21
Balance, March 31, 2022	$ 12,326	$ 817	$ (2,016)	$ 400	$ 11,527
Net loss	—	(111)	—	(2)	(113)
Changes in equity of noncontrolling interests	—	—	—	(9)	(9)
Distribution to member	—	(47)	—	—	(47)
Other comprehensive income, net of income taxes	—	—	24	—	24
Balance, June 30, 2022	$ 12,326	$ 659	$ (1,992)	$ 389	$ 11,382
Net loss	—	(188)	—	(5)	(193)
Changes in equity of non-controlling interest	—	—	—	(18)	(18)
Distribution to member	—	(46)	—	—	(46)
Other comprehensive income, net of income taxes	—	—	23	—	23
Balance, September 30, 2022	$ 12,326	$ 425	$ (1,969)	$ 366	$ 11,148

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2021				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2020	$ 9,624	$ 2,805	$ (30)	$ 2,277	$ 14,676
Net (loss) income	—	(793)	—	24	(769)
Changes in equity of noncontrolling interests	—	—	—	(10)	(10)
Distributions to member	—	(458)	—	—	(458)
Other comprehensive income, net of income taxes	—	—	1	—	1
Balance, March 31, 2021	$ 9,624	$ 1,554	$ (29)	$ 2,291	$ 13,440
Net (loss) income	—	(61)	—	74	13
Changes in equity of noncontrolling interests	—	—	—	(12)	(12)
Distribution to member	—	(458)	—	—	(458)
Other comprehensive income, net of income taxes	—	—	2	—	2
Balance, June 30, 2021	$ 9,624	$ 1,035	$ (27)	$ 2,353	$ 12,985
Net income	—	607	—	26	633
Changes in equity of noncontrolling interest	—	—	—	(13)	(13)
Acquisition of CENG noncontrolling interest	1,080	—	—	(1,965)	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	(288)	—	—	—	(288)
Contribution from member	64	—	—	—	64
Distributions to member	—	(457)	—	—	(457)
Other comprehensive loss, net of income taxes	—	—	(4)	—	(4)
Balance, September 30, 2021	$ 10,480	$ 1,185	$ (31)	$ 401	$ 12,035

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 (the separation), 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 as of September 30, 2022 and for the three and nine months ended September 30, 2022 and 2021 are unaudited but, in our opinion include all adjustments that are considered necessary for a fair statement of the financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. 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. Constellation's December 31, 2021 Consolidated Balance Sheet was derived from audited financial statements. The interim financial statements are to be read in conjunction with prior annual financial statements and notes. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2022. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. 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.

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 now 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 facility agreements providing $4.5 billion of capacity.

Beginning on February 1, 2022, the amounts Exelon billed us for services pursuant to the TSA were $68 million and $193 million for the three and nine months ended September 30, 2022, respectively, and the amounts we billed Exelon for services pursuant to the TSA were $12 million and $32 million for the three and nine months ended September 30, 2022, respectively.

See Note 1 — Significant Accounting Policies of our 2021 Form 10-K for additional information on significant accounting policies. The following policy was added as a result of separation.

Retirement Benefits

Effective upon separation, we sponsor defined benefit pension and OPEB plans as described in Note 11 — Retirement Benefits. The plan obligations and costs of providing benefits under these plans were measured as of February 1, 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.

2. Mergers, Acquisitions, and Dispositions

CENG Put Option

Prior to August 6, 2021, we owned a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG was 100% consolidated in our financial statements. See Note 21 — Variable Interest Entities of our 2021 Form 10-K for additional information.

(Dollars in millions, unless otherwise noted)

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 have 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 in 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 10 — Income Taxes for additional information.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Net income (loss) attributable to membership interest	$ 607	$ (247)
Pre-tax increase in membership interest for purchase of EDF's 49.99% equity interest[(a)]	1,080	1,080
Decrease in membership interest due to deferred tax liabilities resulting from purchase of EDF's equity interest[(a)]	(288)	(288)
Change from net income (loss) attributable to membership interest and transfers from noncontrolling interest.	$ 1,399	$ 545

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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 MW 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 Statements of Operations and Comprehensive Income.

See Note 17 — Debt and Credit Agreements of our 2021 Form 10-K for additional information on the SolGen nonrecourse debt included as part of the transaction.

Agreement for the 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 Statements 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

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 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. See Note 3 – Regulatory Matters of our 2021 Form 10-K for additional information.

As a result of this event, we incurred a loss of approximately $880 million for the nine months ended September 30, 2021. By comparison, for the nine months ended September 30, 2022, the estimated impact reduced our overall Net loss by approximately $30 million, primarily the result of impacts from a payment to ERCOT from a defaulting market participant and the settlement of a dispute related to gas penalties. The estimated impact to our Net loss for the three months ended September 30, 2022 and 2021 was not material.

In response to the high demand and significantly reduced total generation on the system, the PUCT directed ERCOT to use an administrative price cap of $9,000/MWh during firm load shedding events. 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; 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 remaining defaults. Due to a market participant paying off their debt to ERCOT, this was reduced to approximately $1.9 billion as of September 30, 2022. Remaining defaults, under ERCOT rules, are allocated to the remaining market participants. We recorded our estimated obligation of the remaining defaults, net of legislative solutions and on a discounted basis, of approximately $16 million and $17 million as of September 30, 2022 and December 31, 2021, respectively, which was expected to be paid over a term of 62 years and 83 years, respectively.

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 remaining default owed to ERCOT. The ERCOT claim is now in mediation and is addressed in the Chapter 11 Plan of Reorganization filed by the Debtor (market participant) on September 1, 2022. The filing does not represent the final terms and conditions of settlements that the Debtor has negotiated or is continuing to negotiate. However, if approved by the bankruptcy court as filed, the issue would be resolved. A ruling is expected in the fourth quarter of 2022, and we cannot reasonably predict the outcome of this proceeding.

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.

New England Regulatory Matters

Mystic Units 8 and 9 Cost of Service Agreement. In November 2021, FERC issued an order directing a decrease to the Return on Equity ("ROE") used in the Mystic Cost of Service Agreement (the "Mystic COS") from 9.33% to 9.19%. The ROE impacts the return Mystic collects on its rate base under the agreement. 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.

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.

On December 20, 2018, FERC issued an order on the key elements of the Mystic COS, including recovery of costs associated with the operation of the Everett Marine Terminal (EMT). On July 17, 2020, FERC issued an order on rehearing of that decision. Both orders were appealed to the U.S. Court of Appeals for the D.C. Circuit. 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. See Note 3 – Regulatory Matters of our 2021 Form 10-K and Note 7 – Early Plant Retirements for additional information.

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.

Federal Regulatory Matters

Inflation Reduction Act of 2022. On August 16, 2022, Congress passed and President Biden signed into law the Inflation Reduction Act of 2022 (IRA of 2022), 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 of 2022 includes a 15% book-minimum tax on applicable corporations. We do not expect this to have a material impact to our financial statements.

Operating License Renewals

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.

On February 24, 2022, the NRC issued an order related to its review of our subsequent license renewal application for Peach Bottom. While the NRC had previously granted subsequent license renewal to the Peach Bottom units, the NRC was responding to a request for hearing that had not previously been adjudicated. In its decision, the NRC reversed itself and concluded that the previous environmental review required by the National Environmental Policy Act (NEPA) for the Peach Bottom subsequently renewed license 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 directed its staff to change the expiration dates for the licenses back to 2033 and 2034, until the completion of the NEPA analysis. The NRC directed, however, that the subsequently renewed licenses themselves remain in effect but requested views from the parties to the proceedings on this and stated that it would issue a follow-on order deciding whether to rescind the subsequently renewed licenses. On March 7, 2022, we filed a motion requesting that the NRC reevaluate its decision to amend the expiration dates of the Peach Bottom licenses. On March 25, 2022, the NRC staff issued a letter to us with amendments to the Peach Bottom license, reverting the expiration dates to 2033 and 2034, as directed by the NRC in its February 24, 2022 order. On June 3, 2022, the NRC issued a follow-on order denying our motion but affirming that the subsequently renewed licenses would not be disturbed. 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. 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.

See Note 4 — Revenue from Contracts with Customers of our 2021 Form 10-K for additional information regarding the primary sources of revenue.

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, respectively, in the Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in the Consolidated Balance Sheets for the three and nine months ended September 30, 2022 and 2021.

(Dollars in millions, unless otherwise noted)

	Contract Assets
Balance as of December 31, 2021	$ 149
Amounts reclassified to receivables	(16)
Revenues recognized	9
Balance as of March 31, 2022	$ 142
Amounts reclassified to receivables	(13)
Revenues recognized	10
Balance as of June 30, 2022	$ 139
Amounts reclassified to receivables	(5)
Revenues recognized	21
Balance as of September 30, 2022	$ 155
Balance as of December 31, 2020	$ 144
Amounts reclassified to receivables	(16)
Revenues recognized	13
Amounts previously held-for-sale	12
Balance as of March 31, 2021	$ 153
Amounts reclassified to receivables	(12)
Revenues recognized	9
Balance as of June 30, 2021	$ 150
Amounts reclassified to receivables	(15)
Revenues recognized	14
Balance as of September 30, 2021	$ 149

Contract Liabilities

We record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. We record contract liabilities in Other current liabilities and Other 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 was initially established at $16.50 per MWh of production up to the annual cap, while requiring delivery of all ZECs produced by our participating nuclear 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.

(Dollars in millions, unless otherwise noted)

The following table provides a rollforward of the contract liabilities reflected in the Consolidated Balance Sheets for the three and nine months ended September 30, 2022 and 2021.

	Contract Liabilities
Balance as of December 31, 2021	$ 75
Consideration received or due	50
Revenues recognized	(63)
Balance as of March 31, 2022	$ 62
Consideration received or due	27
Revenues recognized	(63)
Balance as of June 30, 2022	$ 26
Consideration received or due	71
Revenues recognized	(68)
Balance as of September 30, 2022	$ 29
Balance as of December 31, 2020	$ 84
Consideration received or due	31
Revenues recognized	(64)
Amounts previously held-for-sale	3
Balance as of March 31, 2021	$ 54
Consideration received or due	39
Revenues recognized	(68)
Balance as of June 30, 2021	$ 25
Consideration received or due	93
Revenues recognized	(65)
Balance as of September 30, 2021	$ 53

The following table reflects revenues recognized in the three and nine months ended September 30, 2022 and 2021, which were included in contract liabilities at December 31, 2021 and 2020, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Revenues recognized	$ 2	$ 2	$ 70	$ 81

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 September 30, 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.

	2022	2023	2024	2025	2026 and thereafter	Total
Remaining performance obligations	$ 97	$ 161	$ 63	$ 32	$ 152	$ 505

Revenue Disaggregation

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

5. Segment Information

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

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

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

The CODM evaluates the performance of our electric business activities and allocates resources based on Revenues less Purchased Power and Fuel Expense (RNF). We believe this is a useful measurement of operational performance, although it is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Our operating revenues include all sales to third parties and affiliate sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for our owned generation and fuel costs associated with tolling agreements. The results of our other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to our overall operating revenues or results of operations. Further, our unrealized mark-to-market gains and losses on economic hedging activities and our amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. The CODM does not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

(Dollars in millions, unless otherwise noted)

The following tables disaggregate the revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. The disaggregation of revenues reflects our two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. The following tables also show the reconciliation of reportable segment revenues and RNF to our total revenues and RNF for the three and nine months ended September 30, 2022 and 2021.

	Three Months Ended September 30, 2022				
	Revenues from external customers[(a)]				
	Contracts with customers	Other[(b)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,561	$ 97	$ 1,658	$ 1	$ 1,659
Midwest	1,182	(133)	1,049	(2)	1,047
New York	536	(110)	426	(3)	423
ERCOT	328	168	496	(6)	490
Other Power Regions	1,315	611	1,926	10	1,936
Total Competitive Businesses Electric Revenues	4,922	633	5,555	—	5,555
Competitive Businesses Natural Gas Revenues	471	599	1,070	—	1,070
Competitive Businesses Other Revenues[(c)]	154	(728)	(574)	—	(574)
Total Consolidated Operating Revenues	$ 5,547	$ 504	$ 6,051	$ —	$ 6,051

	Three Months Ended September 30, 2021				
	Revenues from external customers[(a)]				
	Contracts with customers	Other[(b)]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,145	$ 123	$ 1,268	$ 4	$ 1,272
Midwest	1,084	(99)	985	—	985
New York	445	10	455	—	455
ERCOT	191	165	356	2	358
Other Power Regions	948	318	1,266	(6)	1,260
Total Competitive Businesses Electric Revenues	3,813	517	4,330	—	4,330
Competitive Businesses Natural Gas Revenues	266	309	575	—	575
Competitive Businesses Other Revenues[(c)]	95	(594)	(499)	—	(499)
Total Consolidated Operating Revenues	$ 4,174	$ 232	$ 4,406	$ —	$ 4,406

(Dollars in millions, unless otherwise noted)

	Nine Months Ended September 30, 2022				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 3,894	$ 70	$ 3,964	$ 3	$ 3,967
Midwest	3,749	(401)	3,348	(3)	3,345
New York	1,492	(314)	1,178	—	1,178
ERCOT	744	476	1,220	(10)	1,210
Other Power Regions	3,756	1,423	5,179	10	5,189
Total Competitive Businesses Electric Revenues	13,635	1,254	14,889	—	14,889
Competitive Businesses Natural Gas Revenues	1,770	1,778	3,548	—	3,548
Competitive Businesses Other Revenues[c]	416	(1,746)	(1,330)	—	(1,330)
Total Consolidated Operating Revenues	$ 15,821	$ 1,286	$ 17,107	$ —	$ 17,107

	Nine Months Ended September 30, 2021				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 3,377	$ 134	$ 3,511	$ 16	$ 3,527
Midwest	3,067	(123)	2,944	1	2,945
New York	1,204	(30)	1,174	(1)	1,173
ERCOT	724	155	879	11	890
Other Power Regions	3,043	713	3,756	(27)	3,729
Total Competitive Businesses Electric Revenues	11,415	849	12,264	—	12,264
Competitive Businesses Natural Gas Revenues	1,384	1,024	2,408	—	2,408
Competitive Businesses Other Revenues[c]	291	(846)	(555)	—	(555)
Total Consolidated Operating Revenues	$ 13,090	$ 1,027	$ 14,117	$ —	$ 14,117

(a) Includes all wholesale and retail electric sales to third parties and affiliate sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. See Note 20 - 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 $681 million and $635 million for the three months ended September 30, 2022 and 2021, respectively, and unrealized mark-to-market losses of $1,899 million and $958 million for the nine months ended September 30, 2022 and 2021, respectively, and the elimination of intersegment revenues.

(Dollars in millions, unless otherwise noted)

	Three Months Ended September 30, 2022			Three Months Ended September 30, 2021		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 553	$ 2	$ 555	$ 567	$ 3	$ 570
Midwest	572	—	572	655	—	655
New York	268	(1)	267	343	3	346
ERCOT	104	(38)	66	181	(2)	179
Other Power Regions	274	(17)	257	233	(22)	211
Total RNF for Reportable Segments	1,771	(54)	1,717	1,979	(18)	1,961
Other[b]	(415)	54	(361)	881	18	899
Total RNF	$ 1,356	$ —	$ 1,356	$ 2,860	$ —	$ 2,860

	Nine Months Ended September 30, 2022			Nine Months Ended September 30, 2021		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,606	$ 6	$ 1,612	$ 1,698	$ 14	$ 1,712
Midwest	2,008	2	2,010	2,014	1	2,015
New York	822	5	827	873	7	880
ERCOT	321	(86)	235	(775)	(147)	(922)
Other Power Regions	741	(31)	710	641	(77)	564
Total RNF for Reportable Segments	5,498	(104)	5,394	4,451	(202)	4,249
Other[b]	(145)	104	(41)	1,563	202	1,765
Total RNF	$ 5,353	$ —	$ 5,353	$ 6,014	$ —	$ 6,014

(a) Includes purchases and sales from/to third parties and affiliate sales to Exelon's utility subsidiaries prior to the separation on February 1, 2022. See Note 20 - 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 $(524) million and gains of $754 million for the three months ended September 30, 2022 and 2021, respectively, and unrealized mark-to-market losses of ($571) million and gains of $1,242 million for the nine months ended September 30, 2022 and 2021, respectively;
- Accelerated nuclear fuel amortization associated with the announced early plant retirements as discussed in Note 7 - Early Plant Retirements of $42 million and $148 million for the three and nine months ended September 30, 2021, respectively.
- The elimination of intersegment RNF.

(Dollars in millions, unless otherwise noted)

6. Accounts Receivable

Allowance for Credit Losses on Accounts Receivable

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

	Three Months Ended September 30, 2022	
Balance as of June 30, 2022[(a)]	$	49
Plus: Current period provision for expected credit losses		9
Less: Write-offs, net of recoveries[(b)]		3
Balance as of September 30, 2022[(a)]	$	55
	Three Months Ended September 30, 2021	
Balance as of June 30, 2021[(a)]	$	75
Plus: Current period provision for expected credit losses		10
Less: Write-offs, net of recoveries[(b)]		1
Balance as of September 30, 2021[(a)]	$	84
	Nine Months Ended September 30, 2022	
Balance as of December 31, 2021[(a)]	$	55
Plus: Current period provision for expected credit losses		12
Less: Write-offs, net of recoveries[(b)]		12
Balance as of September 30, 2022[(a)]	$	55
	Nine Months Ended September 30, 2021	
Balance as of December 31, 2020[(a)]	$	32
Plus: Current period provision for expected credit losses[(c)]		57
Less: Write-offs, net of recoveries[(b)]		5
Balance as of September 30, 2021[(a)]	$	84

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(a) Allowance for Credit Losses on Other Accounts Receivable were not material as of the balance sheet dates.
(b) Recoveries were not material.
(c) Primarily relates to the impacts of the February 2021 extreme cold weather event. See Note 3 — Regulatory Matters for additional information.

Unbilled Customer Revenue

We recorded $369 million and $373 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of September 30, 2022 and December 31, 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. No additional funds were drawn in connection with the amendment. 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

(Dollars in millions, unless otherwise noted)

Purchasers is referred to as the DPP, which is reflected in Other current assets in the Consolidated Balance Sheets.

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

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

	As of September 30, 2022	As of December 31, 2021
Derecognized receivables transferred at fair value	$ 1,675	$ 1,265
Cash proceeds received	700	900
DPP	975	365

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Loss on sale of receivables[(a)]	$ 15	$ 1	$ 39	$ 26

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

	Nine Months Ended September 30,	
	2022	2021
Proceeds from new transfers[(a)]	$ 4,807	$ 4,440
Cash collections received on DPP and reinvested in the Facility[(b)]	3,295	2,652
Cash collections reinvested in the Facility	8,102	7,092

(a) Customer accounts receivable sold into the Facility were $8,540 million and $7,373 million for the nine months ended September 30, 2022 and 2021, respectively.
(b) Does not include $200 million net cash payments to the Purchasers in the third quarter of 2022 and $400 million cash proceeds received from the Purchasers in the first quarter of 2021.

Our risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred. 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 14 — Fair Value of Financial Assets and Liabilities and Note 18 — 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 include Exelon's utility subsidiaries. The following table presents the total receivables sold.

	Nine Months Ended September 30,	
	2022	2021
Total receivables sold	$ 312	$ 117
Related party transactions:		
Receivables sold to Exelon's utility subsidiaries prior to the separation on February 1, 2022	4	17

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 of 2022, 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 of our 2021 Form 10-K 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 of our 2021 Form 10-K 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.

(Dollars in millions, unless otherwise noted)

The total impact for the three and nine months ended September 30, 2021 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.

Income statement expense (pre-tax)	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Depreciation and amortization		
Accelerated depreciation[(a)]	$ 574	$ 1,805
Accelerated nuclear fuel amortization	42	148
Operating and maintenance		
One-time charges	(94)	(94)
Other charges	4	8
Contractual offset[(b)]	(60)	(451)
Total	$ 466	$ 1,416

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(a) Includes the accelerated depreciation of plant assets including any ARC.
(b) 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 of our 2021 Form 10-K 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 - 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, 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 three and nine months ended September 30, 2022. We recorded an immaterial amount of incremental Depreciation and amortization expense for the three months ended September 30, 2021 and $41 million for the nine months ended September 30, 2021.

(Dollars in millions, unless otherwise noted)

8. Nuclear Decommissioning

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.

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, 2021 to September 30, 2022:

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		394
Costs incurred related to decommissioning plants		(50)
Balance as of September 30, 2022[(a)]	$	12,372

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(a) Includes $45 million and $72 million as the current portion of the ARO as of September 30, 2022 and December 31, 2021, respectively, which is included in Other current liabilities in the Consolidated Balance Sheets.

During the nine months ended September 30, 2022, the net $648 million decrease in the ARO for the 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 of 2022 and useful life extension for Clinton and Dresden plants. See Note 3 - Regulatory Matters and Note 7 - Early Plant Retirements for additional information
- An 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 three and nine months ended September 30, 2022 in the Consolidated Statement of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

NDT Funds

We had NDT funds totaling $13,546 million and $16,064 million as of September 30, 2022 and December 31, 2021, respectively. The NDT funds also include $93 million and $126 million for the current portion of the NDT funds as of September 30, 2022 and December 31, 2021, respectively, which are included in Other current assets in the Consolidated Balance Sheets. See Note 19 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate our obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, respectively, 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. See Note 10 — Asset Retirement Obligations of our 2021 Form 10-K for additional information on our continued obligations associated with the former ComEd and PECO nuclear units.

The following table presents our noncurrent payables to ComEd and PECO which are recorded as Payables related to Regulatory Agreement Units as of September 30, 2022 and noncurrent Payables to affiliates as of December 31, 2021:

	September 30, 2022	December 31, 2021
ComEd	$ 2,469	$ 2,760
PECO	189	597

Additionally, during the second and third quarter of 2021, a pre-tax charge of $53 million and $140 million, respectively, 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 the temporary suspension of contractual offset accounting. With our September 15, 2021 reversal of the previous decision to retire Byron and the corresponding adjustment to the ARO for Byron, we resumed contractual offset for Byron as of that date.

See Note 10 — Asset Retirement Obligations of our 2021 Form 10-K for additional information on adjustments to the Byron ARO.

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.

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. No additional actions are required aside from the PAPUC filing in accordance with the tariff. See Note 10 – Asset Retirement Obligations of our 2021 Form 10-K for information regarding the amount collected from PECO customers for decommissioning costs of the former PECO nuclear units.

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 fall below investment grade.

See Note 1 — Basis of Presentation for additional information.

9. Asset Impairments

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

New England Asset Group

In the 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 Statements 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 EGRP 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

(Dollars in millions, unless otherwise noted)

Net income attributable to noncontrolling interests in the Consolidated Statements of Operations and Comprehensive Income.

Agreement for the Sale of Our Biomass Facility

See Note 2 — Mergers, Acquisitions, and Dispositions for information on a pre-tax impairment recorded in the second quarter of 2021 related to the Albany Green Energy biomass facility.

10. Income Taxes

Rate Reconciliation

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

	Three Months Ended September 30,	
	2022[(a)]	2021
U.S. federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	(9.5)	4.4
Qualified NDT fund income and losses	22.1	0.9
Amortization of investment tax credit, including deferred taxes on basis differences	1.9	(0.7)
Production tax credits and other credits	8.0	(1.4)
Noncontrolling interests	(0.5)	(0.6)
Other	(3.6)	(1.9)
Effective income tax rate[(b)]	39.4 %	21.7 %

	Nine Months Ended September 30,	
	2022[(a)]	2021[(a)]
U.S. federal statutory rate	21.0 %	21.0 %
Increase (decrease) due to:		
State income taxes, net of federal income tax benefit	(9.0)	90.2
Qualified NDT fund income and losses	48.6	(1,932.6)
Amortization of investment tax credit, including deferred taxes on basis differences	2.0	130.6
Production tax credits and other credits	8.3	425.1
Noncontrolling interests	—	145.2
Other	2.2	(229.5)
Effective income tax rate[(b)]	73.1 %	(1,350.0)%

(a) For every period, except the three months ended September 30, 2021, we recognized a loss on Income before income taxes. As a result, positive percentages represent an income tax benefit and negative percentages represent income tax expense for the periods presented.
(b) The 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. The effective tax rate in 2021 is primarily due to the impacts of the February 2021 extreme cold weather event on Income before income taxes.

(Dollars in millions, unless otherwise noted)

Recognition of Unrecognized Tax Benefits

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

September 30, 2022	$	29
December 31, 2021		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.

Other Tax Matters

CENG Put Option

On August 6, 2021, we entered into a settlement agreement pursuant to which we purchased EDF's equity interest in CENG. We recorded deferred tax liabilities of $288 million in Membership Interest in our 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.

Tax Matters Agreement

In connection with the separation, we entered into a 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 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 reflected a payable of $103 million upon separation 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 March 31, 2022. As of September 30, 2022, the amounts within Accounts payable and Noncurrent other liabilities are $55 million and $50 million, respectively.

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 Exelon tax sharing agreement then existing, 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 September 30, 2022, we had $106 million in Other accounts receivable and $409 million in Other deferred debits and other assets for the reclassified tax attributes.

(Dollars in millions, unless otherwise noted)

11. 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 current participants (inclusive of employees transferred 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 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 present our benefit obligations net of plan assets on our balance sheet within the following line items:

	September 30, 2022		December 31, 2021	
	Pension Benefits	OPEB	Pension Benefits	OPEB
Prepaid pension asset	$ —	$ —	$ 1,683	$ —
Other current liabilities	(9)	(17)	—	—
Pension obligations	(636)	—	—	—
Non-pension postretirement benefit obligations	—	(861)	—	(847)
(Unfunded) funded status (net benefit obligation less plan assets)	$ (645)	$ (878)	$ 1,683	$ (847)

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.

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 expectations regarding future long-term capital market performance, weighted by our target asset class allocations.

(Dollars in millions, unless otherwise noted)

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. In 2022, we adopted the revised mortality tables and projection scales released by the SOA.

The following table summarizes the assumptions we used to determine the benefit obligations as of February 1, 2022 and costs for 2022:

	Pension	OPEB
Discount rate[(a)]	3.23 %	3.21 %
Investment crediting rate[(b)]	3.86 %	N/A
Expected return on plan assets[(c)]	7.00 %	6.50 %
Rate of compensation increase	3.75 %	3.75 %
Mortality table	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	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.
(c) Applicable to our pension and OPEB plans with plan assets, with the OPEB rate representing a weighted average.

Components of Net Periodic Benefit Costs (Credits)

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.

(Dollars in millions, unless otherwise noted)

The following tables present the components of our net periodic benefit costs (credits), prior to capitalization and co-owner allocations, for the three and nine months ended September 30, 2022 and 2021:

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,		Three Months Ended September 30,	
	2022	2021	2022	2021	2022	2021
Components of net periodic benefit cost (credit)						
Service cost	$ 31	$ 36	$ 6	$ 8	$ 37	$ 44
Non-service components of pension benefits & OPEB cost (credit)						
Interest cost	74	59	14	12	88	71
Expected return on assets	(143)	(123)	(14)	(15)	(157)	(138)
Amortization of:						
Prior service cost (credit)	—	—	(2)	(3)	(2)	(3)
Actuarial loss (gain)	37	50	—	3	37	53
Settlement charges	5	10	—	—	5	10
Non-service components of pension benefits & OPEB credit[a]	(27)	(4)	(2)	(3)	(29)	(7)
Net periodic benefit cost[b,c]	$ 4	$ 32	$ 4	$ 5	$ 8	$ 37

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021	2022	2021
Components of net periodic benefit cost (credit)						
Service cost	$ 94	$ 109	$ 18	$ 22	$ 112	$ 131
Non-service components of pension benefits & OPEB cost (credit)						
Interest cost	217	177	42	34	259	211
Expected return on assets	(423)	(370)	(42)	(44)	(465)	(414)
Amortization of:						
Prior service cost (credit)	1	—	(5)	(7)	(4)	(7)
Actuarial loss (gain)	111	149	(1)	8	110	157
Settlement charges	5	14	—	—	5	14
Non-service components of pension benefits & OPEB credit[a]	(89)	(30)	(6)	(9)	(95)	(39)
Net periodic benefit cost[b,c]	$ 5	$ 79	$ 12	$ 13	$ 17	$ 92

(a) The pension benefit and OPEB non-service costs (credits) for the three and nine months ended September 30, 2021 are reflected in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income. Effective February 1, 2022, these non-service costs (credits) are reflected in Other, net in the Consolidated Statements of Operations and Comprehensive Income.

(b) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2022 totaled $33 million and $98 million, respectively. The pension benefit and OPEB non-service credits reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2022 totaled ($27) million and ($85) million, respectively.

(Dollars in millions, unless otherwise noted)

(c) The pension benefit and OPEB service costs reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2021 totaled $32 million and $103 million, respectively. The pension benefit and OPEB non-service credits reflected in the Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2021 totaled ($11) million and ($36) million, respectively.

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 September 30, 2022:

	September 30, 2022
Pension plans	12.2
OPEB plans:	
Benefit Eligibility Age	7.5
Expected Retirement	8.3

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 of 2006 (the Act), and management of the pension obligation. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status on an ABO basis 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. There are no additional contributions expected for the remainder of 2022.

Our non-qualified pension plans are not funded given that they are not subject to statutory minimum contribution requirements. While OPEB plans are also not subject to statutory minimum contribution requirements, we do fund certain plans. For our funded OPEB plans, contributions generally equal accounting costs; however, we consider several factors in determining the level of contributions to these plans, including liabilities management and levels of benefit claims paid. The estimated benefit payments to the non-qualified pension plans in 2022 are $21 million and the planned contributions to the OPEB plans, including estimated benefit payments to unfunded plans is $27 million. The benefit payments to the non-qualified pension plans and OPEB plans were $8 million and $8 million for the three months ended September 30, 2022, respectively. The benefit payments to the non-qualified pension plans and OPEB plans were $16 million and $21 million for the nine months ended September 30, 2022, respectively.

(Dollars in millions, unless otherwise noted)

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all pension and OPEB plans were:

	Pension Benefits	OPEB
2022[a]	$ 532	$ 108
2023	521	108
2024	524	108
2025	536	107
2026	533	107
2027 through 2031	2,710	540
Total estimated future benefits payments through 2031	$ 5,356	$ 1,078

(a) Amount represents estimated benefit payments for the calendar year.

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 liabilities. 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 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.

Defined Contribution Savings Plans

We sponsor the Constellation Employee Savings Plan, a 401(k) defined contribution savings plan. 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 $16 million and $14 million for the three months ended September 30, 2022 and 2021, respectively, and $44 million and $40 million for the nine months ended September 30, 2022 and 2021, respectively.

12. Derivative Financial Instruments

We use derivative instruments to manage commodity price risk, interest rate risk, and foreign exchange risk related to ongoing business operations.

Authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include NPNS, cash flow hedges, and fair value hedges. All derivative economic hedges related to commodities, referred to as economic hedges, are recorded at fair value through earnings. For all NPNS derivative instruments, accounts receivable or accounts payable are recorded when derivatives settle and revenue or expense is recognized in earnings as the underlying physical commodity is sold or consumed.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the 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 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 September 30, 2022 and December 31, 2021:

(Dollars in millions, unless otherwise noted)

September 30, 2022	Economic Hedges	Proprietary Trading	Collateral [a][b]	Netting[a]	Total
Mark-to-market derivative assets (current assets)	$ 27,702	$ 24	$ (372)	$ (24,816)	$ 2,538
Mark-to-market derivative assets (noncurrent assets)	7,103	1	(27)	(5,848)	1,229
Total mark-to-market derivative assets	34,805	25	(399)	(30,664)	3,767
Mark-to-market derivative liabilities (current liabilities)	(27,225)	(21)	50	24,816	(2,380)
Mark-to-market derivative liabilities (noncurrent liabilities)	(7,205)	—	114	5,848	(1,243)
Total mark-to-market derivative liabilities	(34,430)	(21)	164	30,664	(3,623)
Total mark-to-market derivative net assets (liabilities)	$ 375	$ 4	$ (235)	$ —	$ 144
December 31, 2021					
Mark-to-market derivative assets (current assets)	$ 10,915	$ 25	$ 152	$ (8,923)	$ 2,169
Mark-to-market derivative assets (noncurrent assets)	3,224	2	15	(2,298)	943
Total mark-to-market derivative assets	14,139	27	167	(11,221)	3,112
Mark-to-market derivative liabilities (current liabilities)	(10,143)	(19)	262	8,923	(977)
Mark-to-market derivative liabilities (noncurrent liabilities)	(2,893)	(1)	83	2,298	(513)
Total mark-to-market derivative liabilities	(13,036)	(20)	345	11,221	(1,490)
Total mark-to-market derivative net assets (liabilities)	$ 1,103	$ 7	$ 512	$ —	$ 1,622

(a) We net all available amounts allowed under the derivative authoritative guidance in our Consolidated Balance Sheets. 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 September 30, 2022 and December 31, 2021 and not reflected in the tables above.
(b) Includes $2,013 million and $897 million of variation margin held from the exchanges as of September 30, 2022 and December 31, 2021, respectively.

Economic Hedges (Commodity Price Risk)

For the three and nine months ended September 30, 2022 and 2021, 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Income Statement Location	(Losses) Gains		(Losses) Gains	
Operating revenues	$ (691)	$ (637)	$ (1,913)	$ (961)
Purchased power and fuel	171	1,392	1,346	2,209
Total	$ (520)	$ 755	$ (567)	$ 1,248

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on owned and contracted generation positions that have not been hedged. For merchant revenues not already hedged via comprehensive state programs, such as the CMC in Illinois, we utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant revenues are hedged on an approximate rolling 90%/60%/30% basis. We may also enter into transactions that are outside of this ratable hedging program. As of September 30, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 92%-95% for 2022 and 2023, respectively.

Proprietary Trading (Commodity Price Risk)

(Dollars in millions, unless otherwise noted)

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 three and nine months ended September 30, 2022 and 2021, activity associated with proprietary trading activities were not material.

Interest Rate and Foreign Exchange Risk

We utilize interest rate swaps to manage our interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were $563 million and $486 million as of September 30, 2022 and December 31, 2021, respectively.

The following table provides the mark-to-market derivative assets and liabilities as of September 30, 2022:

September 30, 2022	Economic Hedges	Netting[(a)]	Total
Mark-to-market derivative assets (current assets)	$ 27	$ (8)	$ 19
Mark-to-market derivative assets (noncurrent assets)	23	—	23
Total mark-to-market derivative assets	50	(8)	42
Mark-to-market derivative liabilities (current liabilities)	(20)	8	(12)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1)	—	(1)
Total mark-to-market derivative liabilities	(21)	8	(13)
Total mark-to-market derivative net assets (liabilities)	$ 29	$ —	$ 29

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(a) We net all available amounts allowed under the derivative authoritative guidance in our Consolidated Balance Sheets. 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 risk for the three and nine months ended September 30, 2022 and 2021 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 commodity 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

(Dollars in millions, unless otherwise noted)

September 30, 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, NGX, and Nodal commodity exchanges.

Rating as of September 30, 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	$ 1,515	$ 584	$ 931	—	$ —
Non-investment grade	14	—	14	—	—
No external ratings					
Internally rated — investment grade	109	—	109	—	—
Internally rated — non-investment grade	330	89	241	—	—
Total	$ 1,968	$ 673	$ 1,295	—	$ —

Net Credit Exposure by Type of Counterparty	As of September 30, 2022
Investor-owned utilities, marketers, power producers	$ 1,057
Energy cooperatives and municipalities	96
Financial institutions	53
Other	89
Total	$ 1,295

(a) As of September 30, 2022, credit collateral held from counterparties where we had credit exposure included $530 million of cash and $143 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 a combination of several months of future payments (e.g., capacity payments) and 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	September 30, 2022	December 31, 2021
Gross fair value of derivative contracts containing this feature[(a)]	$ (8,882)	$ (3,872)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	5,336	2,424
Net fair value of derivative contracts containing this feature[(c)]	$ (3,546)	$ (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 September 30, 2022 and December 31, 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.

	September 30, 2022	December 31, 2021
Cash collateral posted[a]	$ 1,370	$ 713
Letters of credit posted[a]	1,146	755
Cash collateral held[a]	1,605	182
Letters of credit held[a]	161	124
Additional collateral required in the event of a credit downgrade below investment grade (at BB+/Ba1)[b][c]	3,115	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.

13. Debt and Credit Agreements

Short-Term Borrowings

We meet our short-term liquidity requirements primarily through the issuance of commercial paper. We may use our credit facility for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects our commercial paper program supported by the revolving credit agreements and bilateral credit agreements as of September 30, 2022 and December 31, 2021:

Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
September 30, 2022	December 31, 2021	September 30, 2022	December 31, 2021
$ 493	$ 702	3.95 %	0.66 %

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

(Dollars in millions, unless otherwise noted)

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establishing a $3.5 billion revolving credit facility at a variable interest rate of SOFR plus 1.275%, with a maturity of February 1, 2027 and on February 9, 2022, we entered into a $1 billion liquidity facility with the primary purpose of supporting our letter of credit issuances with a maturity of January 31, 2027.

As of September 30, 2022, we had the following aggregate bank commitments, credit facility borrowings and available capacity under our respective credit facilities:

				Available Capacity as of September 30, 2022	
Facility Type	**Aggregate Bank Commitment**	**Facility Draws**	**Outstanding Letters of Credit**	**Actual**	**To Support Additional Commercial Paper**
Syndicated Revolver[(a)]	$ 3,500	$ —	$ 1,503	$ 1,997	$ 1,504
Bilaterals[(b)]	1,200	—	1,034	166	—
Liquidity Facility[(c)]	971	—	861	110	—
Project Finance	131	—	111	20	—
Total	$ 5,802	$ —	$ 3,509	$ 2,293	$ 1,504

(a) Excludes $44 million of credit facility agreements arranged at minority and community banks. These facilities expired on October 7, 2022. As of September 30, 2022, there were no letters of credit issued under these facilities.
(b) On July 15, 2022, a bilateral credit agreement initiated on November 21, 2019 decreased from $150 million to $100 million. On August 12, 2022, we initiated a new bilateral credit agreement for $50 million. This credit agreement does not contain a maturity date and is automatically renewed based on the contingency standards within the specific agreement. On August 24, 2022, we initiated a new bilateral credit agreement for $100 million with a maturity date of August 23, 2024.
(c) 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 September 30, 2022, without posting additional collateral, the actual availability of facility, prior to outstanding letters of credit was $877 million.

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 date of March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder is unsecured. 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 Sheet 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 bear interest at a variable rate of LIBOR plus 0.875% until March 31, 2022 and a rate of LIBOR plus 1% thereafter and all indebtedness thereunder is unsecured. The loan agreement was amended on January 24, 2022 to change the maturity date to June 30, 2022 from August 5, 2022. We repaid the term loan on April 15, 2022 that was reflected in Short-term borrowings in the Consolidated Balance Sheet as of December 31, 2021. See Note 2 — Mergers, Acquisitions, and Dispositions of our 2021 Form 10-K for additional information.

(Dollars in millions, unless otherwise noted)

Long-Term Debt

Debt Issuances and Redemptions

During the nine months ended September 30, 2022, the following long-term debt was issued:

Type	Interest Rate	Maturity	Amount	Use of Proceeds
Energy Efficiency Project Financing[(a)]	2.20% - 2.44%	March 31, 2023 - February 29, 2024	$ 9	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 the nine months ended September 30, 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	3 month LIBOR + 2.50%	December 15, 2027	41
Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	36
West Medway II Nonrecourse Debt	1 month LIBOR + 2.875%	March 31, 2026	17
Antelope Valley DOE Nonrecourse Debt	2.29% - 3.56%	January 5, 2037	14
RPG Nonrecourse Debt	4.11%	March 31, 2035	9
Energy Efficiency Project Financing	3.71%	December 31, 2022	3

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 Corporate. In connection with the separation, on January 31, 2022, we paid cash to Exelon Corporate in the amount of $258 million to settle the intercompany loan with the difference of $61 million recorded to membership interest.

Debt Covenants

As of September 30, 2022, we are in compliance with all debt covenants.

14. Fair Value of Financial Assets and Liabilities

We measure and classify fair value measurements in accordance with the hierarchy as defined by GAAP. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

(Dollars in millions, unless otherwise noted)

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of the short-term liabilities, long-term debt, and the SNF obligation as of September 30, 2022 and December 31, 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.

	September 30, 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	$ 4,661	$ 3,577	$ 907	$ 4,484	$ 6,114	$ 5,749	$ 1,093	$ 6,842
SNF Obligation	1,219	975	—	975	1,210	1,060	—	1,060

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 September 30, 2022 and December 31, 2021:

(Dollars in millions, unless otherwise noted)

	As of September 30, 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)]	$ 16	$ —	$ —	$ —	$ 16	$ 113	$ —	$ —	$ —	$ 113
NDT fund investments										
Cash equivalents[(b)]	494	94	—	—	588	465	116	—	—	581
Equities	3,153	1,330	2	1,145	5,630	4,564	1,805	—	1,645	8,014
Fixed income										
Corporate debt[(c)]	—	982	264	—	1,246	—	1,145	286	—	1,431
U.S. Treasury and agencies	1,960	19	—	—	1,979	2,193	30	—	—	2,223
Foreign governments	—	42	—	—	42	—	60	—	—	60
State and municipal debt	—	46	—	—	46	—	26	—	—	26
Other	20	19	—	1,665	1,704	29	23	—	1,449	1,501
Fixed income subtotal	1,980	1,108	264	1,665	5,017	2,222	1,284	286	1,449	5,241
Private credit	—	—	164	640	804	—	—	178	624	802
Private equity	—	—	—	678	678	—	—	—	673	673
Real estate	—	—	—	1,007	1,007	—	—	—	864	864
NDT fund investments subtotal[(d)(e)]	5,627	2,532	430	5,135	13,724	7,251	3,205	464	5,255	16,175
Rabbi trust investments										
Cash equivalents	1	—	—	—	1	3	—	—	—	3
Mutual funds	36	—	—	—	36	36	—	—	—	36
Life insurance contracts	—	27	1	—	28	—	33	—	—	33
Rabbi trust investments subtotal	37	27	1	—	65	39	33	—	—	72
Investments in equities	6	—	—	—	6	43	—	—	—	43
Mark-to-market derivative assets										
Economic hedges	6,689	16,175	11,991	—	34,855	3,017	7,223	3,899	—	14,139
Proprietary trading	—	11	14	—	25	—	19	8	—	27
Effect of netting and allocation of collateral[(f)(g)]	(5,233)	(15,882)	(9,956)	—	(31,071)	(2,108)	(6,177)	(2,769)	—	(11,054)
Mark-to-market derivative assets subtotal	1,456	304	2,049	—	3,809	909	1,065	1,138	—	3,112
DPP consideration	—	975	—	—	975	—	365	—	—	365
Total assets	7,142	3,838	2,480	5,135	18,595	8,355	4,668	1,602	5,255	19,880
Liabilities										
Mark-to-market derivative liabilities										
Economic hedges	(5,438)	(15,909)	(13,104)	—	(34,451)	(2,201)	(6,870)	(3,965)	—	(13,036)
Proprietary trading	—	(12)	(9)	—	(21)	—	(18)	(2)	—	(20)
Effect of netting and allocation of collateral[(f)(g)]	5,492	15,733	9,611	—	30,836	2,189	6,642	2,735	—	11,566
Mark-to-market derivative liabilities subtotal	54	(188)	(3,502)	—	(3,636)	(12)	(246)	(1,232)	—	(1,490)
Deferred compensation obligation	—	(53)	—	—	(53)	—	(43)	—	—	(43)
Total liabilities	54	(241)	(3,502)	—	(3,689)	(12)	(289)	(1,232)	—	(1,533)
Total net assets (liabilities)	$ 7,196	$ 3,597	$ (1,022)	$ 5,135	$ 14,906	$ 8,343	$ 4,379	$ 370	$ 5,255	$ 18,347

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(a) CEG Parent has $44 million of Level 1 cash equivalents as of September 30, 2022. We exclude cash of $1,123 million and $417 million as of September 30, 2022 and December 31, 2021, respectively, and restricted cash of $75 million and $46 million as of September 30, 2022 and December 31, 2021, respectively. CEG Parent has excluded an additional $61 million of cash as of September 30, 2022.
(b) Includes $89 million and $116 million of cash received from outstanding repurchase agreements as of September 30, 2022 and December 31, 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 ($38) million and ($55) million as of September 30, 2022 and December 31, 2021, respectively, held in an investment vehicle primarily to hedge the equity option component of convertible debt.
(d) Includes net derivative liabilities of $1 million, which have total notional amounts of $432 million and $687 million as of September 30, 2022 and December 31, 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 $178 million and $111 million as of September 30, 2022 and December 31, 2021, respectively, which include certain derivative assets that have notional amounts of $140 million and $182 million as of September 30, 2022 and December 31, 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) Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $259 million, ($149) million, and ($345) million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of September 30, 2022. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $81 million, $465 million, and ($34) million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2021.
(g) Includes $2,013 million and $897 million of variation margin held from the exchanges as of September 30, 2022 and December 31, 2021, respectively.

As of September 30, 2022, we have outstanding commitments to invest in private credit, private equity, and real estate investments of $242 million, $144 million, and $412 million, respectively. These commitments will be funded by our existing NDT funds.

We hold investments without readily determinable fair values with carrying amounts of $45 million and $33 million as of September 30, 2022 and December 31, 2021, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and nine months ended September 30, 2022 and the year ended December 31, 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 three and nine months ended September 30, 2022 and 2021:

(Dollars in millions, unless otherwise noted)

	For the Three Months Ended September 30, 2022			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of June 30, 2022	$ 431	$ (743)	$ 1	$ (311)
Total realized / unrealized (losses) gains				
Included in net income	—	(925) (a)	—	(925)
Included in Payable related to Regulatory Agreement Units	(2)	—	—	(2)
Change in collateral	—	(58)	—	(58)
Purchases, sales, issuances and settlements				
Purchases	—	333	—	333
Sales	—	(7)	—	(7)
Settlements	—	—	—	—
Transfers into Level 3	1	1 (b)	—	2
Transfers out of Level 3	—	(54) (b)	—	(54)
Balance as of September 30, 2022	$ 430	$ (1,453)	$ 1	$ (1,022)
The amount of total (losses) gains included in income attributed to the change in unrealized (losses) gains related to assets and liabilities as of September 30, 2022	$ (1)	$ (889)	$ —	$ (890)

	For the Three Months Ended September 30, 2021		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of June 30, 2021	$ 461	$ (465)	$ (4)
Total realized / unrealized gains (losses)			
Included in net income	3	(970) (a)	(967)
Included in noncurrent payables to affiliates	11	—	11
Change in collateral	—	(413)	(413)
Purchases, sales, issuances and settlements			
Purchases	2	6	8
Sales	—	6	6
Settlements	(2)	—	(2)
Transfers into Level 3	—	2 (b)	2
Transfers out of Level 3	—	(27) (b)	(27)
Balance as of September 30, 2021	$ 475	$ (1,861)	$ (1,386)
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2021	$ 3	$ (1,004)	$ (1,001)

(Dollars in millions, unless otherwise noted)

	For the Nine Months Ended September 30, 2022			
	NDT Fund Investments	Mark-to-Market Derivatives	Life Insurance Contracts	Total
Balance as of December 31, 2021	$ 464	$ (94)	$ —	$ 370
Total realized / unrealized losses				
Included in net income	(2)	(1,823) (a)	(2)	(1,827)
Included in Payable related to Regulatory Agreement Units	(11)	—	—	(11)
Change in collateral	—	(312)	—	(312)
Impacts of separation	—	—	3	3
Purchases, sales, issuances and settlements				
Purchases	5	499	—	504
Sales	—	(44)	—	(44)
Settlements	(28)	(30)	—	(58)
Transfers into Level 3	2	418 (b)	—	420
Transfers out of Level 3	—	(67) (b)	—	(67)
Balance as of September 30, 2022	$ 430	$ (1,453)	$ 1	$ (1,022)
The amount of total losses included in income attributed to the change in unrealized losses related to assets and liabilities as of September 30, 2022	$ (2)	$ (1,951)	$ (2)	$ (1,955)

	For the Nine Months Ended September 30, 2021		
	NDT Fund Investments	Mark-to-Market Derivatives	Total
Balance as of December 31, 2020	$ 497	$ 430	$ 927
Total realized / unrealized gains (losses)			
Included in net income	4	(1,606) (a)	(1,602)
Included in noncurrent payables to affiliates	18	—	18
Change in collateral	—	(751)	(751)
Purchases, sales, issuances and settlements			
Purchases	3	120	123
Sales	—	7	7
Settlements	(48)	—	(48)
Transfers into Level 3	1	3 (b)	4
Transfers out of Level 3	—	(64) (b)	(64)
Balance as of September 30, 2021	$ 475	$ (1,861)	$ (1,386)
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2021	$ 4	$ (1,527)	$ (1,523)

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(a) Includes a reduction of $35 million for realized gains and an addition of $98 million for realized losses due to the settlement of derivative contracts for the three and nine months ended September 30, 2022, respectively. Includes an addition of $34 million for realized losses and a reduction of $80 million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 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 tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2022 and 2021:

(Dollars in millions, unless otherwise noted)

	For the Three Months Ended September 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2022	2021	2022	2021	2022	2021
Total (losses) gains included in net income	$ (545)	$ (1,274)	$ (380)	$ 304	$ —	$ 3
Total unrealized (losses) gains	(768)	(1,361)	(121)	357	(1)	3

	For the Nine Months Ended September 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2022	2021	2022	2021	2022	2021
Total (losses) gains included in net income	$ (1,786)	$ (1,944)	$ (67)	$ 338	$ (4)	$ 4
Total unrealized (losses) gains	(2,353)	(1,969)	402	443	(4)	4

Valuation Techniques Used to Determine Fair Value

Our valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 18 — Fair Value of Financial Assets and Liabilities of our 2021 Form 10-K.

Valuation Techniques Used to Determine Net Asset Value

Certain NDT Fund Investments are not classified within the fair value hierarchy and are included under the heading “Not subject to leveling” in the table above. These investments are measured at fair value using NAV per share as a practical expedient and include commingled funds, mutual funds which are not publicly quoted, managed private credit funds, private equity and real estate funds.

For commingled funds and mutual funds, which are not publicly quoted, the fair value is primarily derived from the quoted prices in active markets on the underlying securities and can typically be redeemed monthly with 30 or less days of notice and without further restrictions. 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. Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. 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 and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

Mark-to-Market Derivatives

See Note 12 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

(Dollars in millions, unless otherwise noted)

The following table presents the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value as of September 30, 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)]	$ (1,113)	$ (66)	Discounted Cash Flow	Forward power price	$9.26	-	$1,108	$100	$8.86	-	$481	$55
				Forward gas price	$2.55	-	$31	$5.25	$1.69	-	$17	$3.50
			Option Model	Volatility percentage	100%	-	128%	113%	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 received on level 3 positions of $345 million and $34 million as of September 30, 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. 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.

15. Commitments and Contingencies

Commitments

Commercial Commitments. Commercial commitments as of September 30, 2022, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2022	2023	2024	2025	2026	2027 and beyond
Letters of credit	$ 3,509	$ 2,125	$ 1,384	$ —	$ —	$ —	$ —
Surety bonds[(a)]	978	256	722	—	—	—	—
Total commercial commitments	$ 4,487	$ 2,381	$ 2,106	$ —	$ —	$ —	$ —

(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.

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 financial statements.

We had accrued undiscounted amounts for environmental liabilities of $122 million and $120 million as of September 30, 2022 and December 31, 2021, 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 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 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 February 28, 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 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 September 30, 2022 and December 31, 2021, we recorded estimated liabilities of approximately $97 million and $81 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2022, approximately $24 million of this amount related to 257 open claims presented to us, while the remaining $73 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 150 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. The motions were taken under advisement. 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 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.

16. Stock-Based Compensation Plans

Stock-Based Compensation

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 three and nine months ended September 30, 2022.

(Dollars in millions, unless otherwise noted)

The following table presents the stock-based compensation expense included in our 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Total stock-based compensation expense included in operating and maintenance expense	$ 53	$ 8	$ 85	$ 30
Income tax benefit	(13)	(2)	(21)	(8)
Total after-tax stock-based compensation expense	$ 40	$ 6	$ 64	$ 22

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.

During the nine months ended September 30, 2022, we granted performance share awards, inclusive of those converted at separation, totaling 1,501,673 shares with a weighted-average grant date fair value of $47.23. As of September 30, 2022, $31 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.0 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.

During the nine months ended September 30, 2022, we granted restricted stock units, inclusive of those converted at separation, totaling 1,371,997 shares with a grant date fair value of $45.22. As of September 30, 2022, $29 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.3 years.

(Dollars in millions, unless otherwise noted)

17. Changes in Accumulated Other Comprehensive Loss

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

Three Months Ended September 30, 2022	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (8)	$ (1,963)	$ (21)	$ (1,992)
OCI before reclassifications	—	—	(6)	(6)
Amounts reclassified from AOCI	(1)	30	—	29
Net current-period OCI	(1)	30	(6)	23
Ending balance	$ (9)	$ (1,933)	$ (27)	$ (1,969)

Three Months Ended September 30, 2021	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (7)	$ —	$ (20)	$ (27)
OCI before reclassifications	(1)	—	(3)	(4)
Net current-period OCI	(1)	—	(3)	(4)
Ending balance	$ (8)	$ —	$ (23)	$ (31)

Nine Months Ended September 30, 2022	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (8)	$ —	$ (23)	$ (31)
Separation-related adjustments	—	(2,006)	—	(2,006)
OCI before reclassifications	(1)	—	(4)	(5)
Amounts reclassified from AOCI	—	73	—	73
Net current-period OCI	(1)	(1,933)	(4)	(1,938)
Ending balance	$ (9)	$ (1,933)	$ (27)	$ (1,969)

Nine Months Ended September 30, 2021	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items(a)	Foreign Currency Items	Total
Beginning balance	$ (7)	$ —	$ (23)	$ (30)
OCI before reclassifications	(1)	—	—	(1)
Net current-period OCI	(1)	—	—	(1)
Ending balance	$ (8)	$ —	$ (23)	$ (31)

(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 11 — Retirement Benefits for additional information. See our Statements of Operations and Comprehensive Income for individual components of AOCI.

(Dollars in millions, unless otherwise noted)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Pension and non-pension postretirement benefit plans:				
Actuarial loss reclassified to periodic benefit cost	$ (9)	$ —	$ (24)	$ —
Pension and non-pension postretirement benefit plans valuation adjustment	—	—	680	—

18. Variable Interest Entities

At September 30, 2022 and December 31, 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.

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 September 30, 2022 and December 31, 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.

	September 30, 2022	December 31, 2021
Cash and cash equivalents	$ 64	$ 35
Restricted cash and cash equivalents	42	48
Accounts receivable		
Customer	25	24
Other	8	6
Inventories, net		
Materials and supplies	12	14
Other current assets	1,022	405
Total current assets	1,173	532
Property, plant and equipment, net	1,971	2,027
Other noncurrent assets	195	215
Total noncurrent assets	2,166	2,242
Total assets[(a)]	$ 3,339	$ 2,774
Long-term debt due within one year	$ 60	$ 70
Accounts payable	19	10
Accrued expenses	20	21
Other current liabilities	2	1
Total current liabilities	101	102
Long-term debt	775	822
Asset retirement obligations	171	151
Other noncurrent liabilities	3	3
Total noncurrent liabilities	949	976
Total liabilities[(b)]	$ 1,050	$ 1,078

(Dollars in millions, unless otherwise noted)

(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, noncurrent unamortized energy contract assets of $183 million and $202 million, disclosed within other noncurrent assets in the table above as of September 30, 2022 and December 31, 2021, respectively.
(b) Our balances include liabilities with recourse of $1 million and $1 million as of September 30, 2022 and December 31, 2021, respectively.

As of September 30, 2022 and December 31, 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 of our 2021 Form 10-K 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.

(Dollars in millions, unless otherwise noted)

As of September 30, 2022 and December 31, 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.

The following table presents summary information about our significant unconsolidated VIE entities:

	September 30, 2022			December 31, 2021		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 716	$ 344	$ 1,060	$ 772	$ 372	$ 1,144
Total liabilities[(a)]	55	206	261	80	216	296
Our ownership interest in VIE[(a)]	—	122	122	—	139	139
Other ownership interests in VIE[(a)]	661	16	677	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 September 30, 2022 and December 31, 2021.

As of September 30, 2022 and December 31, 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.	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.

19. Supplemental Financial Information

Supplemental Statement of Operations Information

The following tables provide additional information about material items recorded within our Consolidated Statements of Operations and Comprehensive Income.

	Operating revenues			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Operating lease income	$ 29	$ 29	$ 46	$ 44
Variable lease income	77	71	204	207

	Taxes other than income taxes			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Gross receipts[(a)]	$ 39	$ 27	$ 100	$ 73
Property	67	66	206	199
Payroll	36	26	99	83

(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			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Decommissioning-related activities:				
Net realized income on NDT funds[(a)]				
Regulatory Agreement Units	$ 61	$ 263	$ 333	$ 698
Non-Regulatory Agreement Units	15	102	115	392
Net unrealized (losses) gains on NDT funds				
Regulatory Agreement Units	(386)	(195)	(1,777)	84
Non-Regulatory Agreement Units	(225)	(88)	(1,077)	38
Regulatory offset to NDT fund-related activities[(b)]	262	(38)	1,160	(607)
Decommissioning-related activities	(273)	44	(1,246)	605
Non-service net periodic benefit credit[(c)]	27	—	79	—
Net unrealized (losses) gains on CTV investments[(d)]	(2)	(179)	(27)	(83)

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of income taxes related to all NDT fund activity for those units. With our September 15, 2021 reversal of the previous decision to retire Byron, we resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of our 2021 Form 10-K 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 11 — Retirement Benefits for additional information.
(d) Net unrealized (losses) gains on CTV investments that became publicly traded in the fourth quarter of 2020 and the first half of 2021.

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded within our Consolidated Statements of Cash Flows.

	Depreciation, amortization and accretion	
	Nine Months Ended September 30,	
	2022	2021
Property, plant, and equipment[(a)]	$ 798	$ 2,698
Amortization of intangible assets, net[(a)]	20	37
Amortization of energy contract assets and liabilities[(b)]	28	23
Nuclear fuel[(c)]	561	810
ARO accretion[(d)]	403	383
Total depreciation, amortization, and accretion	$ 1,810	$ 3,951

(a) Included in Depreciation and amortization expense in the Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Operating revenues or Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Purchased power and fuel expense in the Consolidated Statements of Operations and Comprehensive Income.
(d) Included in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.

(Dollars in millions, unless otherwise noted)

	Other non-cash operating activities			
	CEG Parent		Constellation	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Pension and non-pension postretirement benefit costs	$ 12	$ 92	$ 12	$ 92
Allowance for credit losses	12	59	12	59
Other decommissioning-related activity[(a)]	(116)	(810)	(116)	(810)
Energy-related options[(b)]	239	45	239	45
Severance costs	—	(75)	—	(75)
Long-term incentive plan	35	—	—	—
Amortization of operating ROU asset	65	98	65	98
Loss on sale of receivables	39	26	39	26
Fair value adjustments related to gas imbalances	65	—	65	—
Prior merger commitment[(c)]	(50)	—	(50)	—

(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 of our 2021 Form 10-K 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 15 - Commitments and Contingencies for additional information.

(Dollars in millions, unless otherwise noted)

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

	CEG Parent	Constellation
September 30, 2022		
Cash and cash equivalents	$ 1,192	$ 1,131
Restricted cash and cash equivalents	111	83
Total cash, restricted cash, and cash equivalents	$ 1,303	$ 1,214
December 31, 2021		
Cash and cash equivalents	$ 504	$ 504
Restricted cash and cash equivalents	72	72
Total cash, restricted cash, and cash equivalents	$ 576	$ 576
September 30, 2021		
Cash and cash equivalents	$ 1,957	$ 1,957
Restricted cash and cash equivalents	62	62
Total cash, restricted cash, and cash equivalents	$ 2,019	$ 2,019
December 31, 2020		
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

For additional information on restricted cash see Note 1 — Significant Accounting Policies of our 2021 Form 10-K.

Supplemental Balance Sheet Information

The following table provides additional information about material items recorded within our Consolidated Balance Sheets.

	Accrued expenses	
September 30, 2022	CEG Parent	Constellation
Compensation-related accruals[(a)]	$ 395	$ 359
Taxes accrued	401	401
December 31, 2021		
Compensation-related accruals[(a)]	$ 356	$ 356
Taxes accrued	272	272

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

20. 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.

(Dollars in millions, unless otherwise noted)

Operating Revenues from Affiliates

The following table presents our Operating revenues from affiliates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022[g]	2021
ComEd[a]	$ —	$ 96	$ 58	$ 249
PECO[b]	—	59	33	142
BGE[c]	—	65	18	195
PHI	—	99	51	276
Pepco[d]	—	69	39	199
DPL[e]	—	25	10	63
ACE[f]	—	5	2	14
Other	—	5	—	10
Total operating revenues from affiliates	$ —	$ 324	$ 160	$ 872

(a) We have an ICC-approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. We also sell RECs and ZECs to ComEd.
(b) We provide electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, we have a ten-year agreement with PECO to sell solar AECs.
(c) We provide a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.
(d) We provide electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
(e) We provide a portion of DPL's energy requirements under its MDPSC and DEPSC approved market-based SOS commodity programs.
(f) We provide electric supply to ACE under contracts executed through ACE's competitive procurement process.
(g) Represents only January 2022 costs prior to separation on February 1, 2022.

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 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			
Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
2022	2021	2022[a]	2021	2022	2021	2022[a]	2021
$ —	$ 145	$ 44	$ 424	$ —	$ 43	$ 15	$ 76

(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 tables present 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

(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 September 30, 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 8 — Nuclear Decommissioning for additional information.

Item 2. **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 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.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth our GAAP consolidated Net (loss) income for the three and nine months ended September 30, 2022 compared to the same period in 2021. For additional information regarding the financial results for the three and nine months ended September 30, 2022 and 2021 see the discussions of Results of Operations below.

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2022	2021		2022	2021	
GAAP Net (loss) income	$ (188)	$ 607	$ (795)	$ (194)	$ (247)	$ 53

Adjusted EBITDA (non-GAAP). In analyzing and planning for our business, we supplement our use of GAAP net income 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 income 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) income attributable to common shareholders as determined in accordance with GAAP and Adjusted EBITDA (non-GAAP) for the three and nine months ended September 30, 2022 compared to the same period in 2021.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Net (Loss) Income Attributable to Common Shareholders	$ (188)	$ 607	$ (194)	$ (247)
Income Taxes[(a)]	(149)	177	(472)	108
Depreciation and Amortization[(b)]	262	866	818	2,735
Interest Expense, Net	75	77	187	225
Unrealized Loss (Gain) on Fair Value Adjustments[(c)]	550	(614)	645	(1,191)
Asset Impairments[(d)]	—	45	—	537
Plant Retirements and Divestitures[(e)]	5	(62)	(3)	(15)
Decommissioning-Related Activities[(f)]	88	(130)	1,126	(1,014)
Pension & OPEB Non-Service Credits	(27)	(11)	(85)	(36)
Separation Costs[(g)]	30	16	99	25
COVID-19 Direct Costs[(h)]	—	5	—	24
Acquisition-Related Costs[(i)]	—	11	—	21
ERP System Implementation Costs[(j)]	5	5	16	10
Change in Environmental Liabilities	3	5	12	7
Cost Management Program	—	4	—	9
Prior Merger Commitment[(k)]	(50)	—	(50)	—
Noncontrolling Interests[(l)]	(12)	(34)	(37)	(40)
Adjusted EBITDA (non-GAAP)	$ 592	$ 967	$ 2,062	$ 1,158

(a) In 2022, includes amounts contractually owed to Exelon under the tax matters agreement 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 of a wind project in the third quarter of 2021, and nine months ended, September 30, 2021 also includes an impairment in the New England asset group, and an impairment recorded as a result of the sale of the Albany Green Energy biomass facility.
(e) In 2021, primarily reflects accelerated nuclear fuel amortization for Byron and Dresden, partially offset by a gain on sale of our solar business which occurred in the first quarter of 2021 and a reversal of one-time charges resulting from the reversal of the previous decision to retire Byron and Dresden.
(f) Reflects all gains and losses associated with NDTs, ARO accretion, ARO remeasurement, and any earnings neutral impacts of contractual offset for Regulatory Agreement Units.
(g) 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.
(h) 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.
(i) Reflects costs related to the acquisition of EDF's interest in CENG, which was completed in the third quarter of 2021.
(j) Reflects costs related to a multi-year Enterprise Resource Program (ERP) system implementation.
(k) Reversal of a charge related to a prior 2012 merger commitment.
(l) 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

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021	Favorable (Unfavorable) Variance
Operating revenues	$ 6,051	$ 4,406	$ 1,645	$ 17,107	$ 14,117	$ 2,990
Operating expenses						
Purchased power and fuel	4,695	1,546	(3,149)	11,754	8,103	(3,651)
Operating and maintenance	989	938	(51)	3,466	3,413	(53)
Depreciation and amortization	262	866	604	818	2,735	1,917
Taxes other than income taxes	145	115	(30)	415	354	(61)
Total operating expenses	6,091	3,465	(2,626)	16,453	14,605	(1,848)
(Loss) gain on sales of assets and businesses	(1)	65	(66)	13	144	(157)
Operating (loss) income	(41)	1,006	(1,047)	667	(344)	1,011
Other income and (deductions)						
Interest expense, net	(75)	(77)	2	(187)	(225)	38
Other, net	(196)	(115)	(81)	(1,169)	561	(1,730)
Total other income and (deductions)	(271)	(192)	(79)	(1,356)	336	(1,692)
(Loss) income before income taxes	(312)	814	(1,126)	(689)	(8)	(681)
Income taxes	(123)	177	300	(504)	108	(612)
Equity in losses of unconsolidated affiliates	(4)	(4)	—	(10)	(6)	(4)
Net (loss) income	(193)	633	(826)	(195)	(122)	(73)
Net (loss) income attributable to noncontrolling interests	(5)	26	(31)	(1)	125	(126)
Net (loss) income attributable to common shareholders	$ (188)	$ 607	$ (795)	$ (194)	$ (247)	53

Three Months Ended September 30, 2022 Compared to Three Months Ended September 30, 2021. **Net (loss) income attributable to common shareholders** was unfavorable by $795 million primarily due to:

- Unfavorable mark-to-market activity;
- Unfavorable net realized and unrealized NDT activity;
- Higher labor, contracting and materials;
- Lower capacity revenues; and
- Unfavorable portfolio optimization activity

The unfavorable items were partially offset by:

- 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;
- Impact of our annual update to the nuclear ARO for Non-Regulatory Agreement Units;
- Favorable impact of net realized and unrealized CTV investment activity; and
- The reversal of a charge related to a 2012 prior merger commitment

Nine months ended September 30, 2022 Compared to Nine months ended September 30, 2021. **Net loss attributable to common shareholders** was favorable by $53 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, the absence of the reversal of charges recorded in the third quarter of 2021 associated with the reversal of the previous decision, and our decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;
- 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;
- Higher realized energy prices;
- Impact of our annual update to the nuclear ARO for Non-Regulatory Agreement Units;
- Lower nuclear fuel costs due to the absence of accelerated amortization of nuclear fuel and lower prices; and
- The reversal of a charge related to a 2012 prior merger commitment

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 impacts from nuclear outages;
- Higher separation costs; 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: natural gas, as well as other miscellaneous business activities that are not significant to overall operating revenues or results of operations.

For the three and nine months ended September 30, 2022 compared to 2021, Operating revenues by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2022	2021	Variance	% Change[(a)]	2022	2021	Variance	% Change[(a)]
Mid-Atlantic	$ 1,659	$ 1,272	$ 387	30.4 %	$ 3,967	$ 3,527	$ 440	12.5 %
Midwest	1,047	985	62	6.3 %	3,345	2,945	400	13.6 %
New York	423	455	(32)	(7.0) %	1,178	1,173	5	0.4 %
ERCOT	490	358	132	36.9 %	1,210	890	320	36.0 %
Other Power Regions	1,936	1,260	676	53.7 %	5,189	3,729	1,460	39.2 %
Total electric revenues	5,555	4,330	1,225	28.3 %	14,889	12,264	2,625	21.4 %
Other	1,177	711	466	65.5 %	4,117	2,811	1,306	46.5 %
Mark-to-market losses	(681)	(635)	(46)		(1,899)	(958)	(941)	
Total Operating revenues	$ 6,051	$ 4,406	$ 1,645	37.3 %	$ 17,107	$ 14,117	$ 2,990	21.2 %

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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)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Variance	% Change	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021	Variance	% Change
Nuclear Generation[a]								
Mid-Atlantic	13,540	13,753	(213)	(1.5)%	39,272	40,203	(931)	(2.3)%
Midwest	24,275	23,909	366	1.5 %	71,079	70,363	716	1.0 %
New York[b]	5,979	6,688	(709)	(10.6)%	18,563	19,820	(1,257)	(6.3)%
Total Nuclear Generation	43,794	44,350	(556)	(1.3)%	128,914	130,386	(1,472)	(1.1)%
Natural Gas, Oil, and Renewables								
Mid-Atlantic	230	491	(261)	(53.2)%	1,573	1,675	(102)	(6.1)%
Midwest	126	177	(51)	(28.8)%	774	763	11	1.4 %
New York	—	—	—	— %	—	1	(1)	(100.0)%
ERCOT	4,987	4,670	317	6.8 %	10,873	10,250	623	6.1 %
Other Power Regions	2,401	2,409	(8)	(0.3)%	7,179	7,641	(462)	(6.0)%
Total Natural Gas, Oil, and Renewables	7,744	7,747	(3)	— %	20,399	20,330	69	0.3 %
Purchased Power								
Mid-Atlantic	6,508	4,565	1,943	42.6 %	12,164	12,123	41	0.3 %
Midwest	74	77	(3)	(3.9)%	425	386	39	10.1 %
ERCOT	705	595	110	18.5 %	2,855	2,626	229	8.7 %
Other Power Regions	13,869	13,585	284	2.1 %	39,964	38,778	1,186	3.1 %
Total Purchased Power	21,156	18,822	2,334	12.4 %	55,408	53,913	1,495	2.8 %
Total Supply/Sales by Region								
Mid-Atlantic	20,278	18,809	1,469	7.8 %	53,009	54,001	(992)	(1.8)%
Midwest	24,475	24,163	312	1.3 %	72,278	71,512	766	1.1 %
New York[b]	5,979	6,688	(709)	(10.6)%	18,563	19,821	(1,258)	(6.3)%
ERCOT	5,692	5,265	427	8.1 %	13,728	12,876	852	6.6 %
Other Power Regions	16,270	15,994	276	1.7 %	47,143	46,419	724	1.6 %
Total Supply/Sales by Region	72,694	70,919	1,775	2.5 %	204,721	204,629	92	— %

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(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants. Includes the total output for fully owned plants and the total output for CENG prior to the acquisition of EDF's interest on August 6, 2021 as CENG was fully consolidated. See Note 2 — Mergers, Acquisitions, and Dispositions of our 2021 Form 10-K 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Nuclear fleet capacity factor[(a)]	96.4 %	97.7 %	94.5 %	95.3 %
Refueling outage days	5	22	147	172
Non-refueling outage days	26	—	51	10

(a) Prior year capacity factor was previously reported as 96.0% and 95.0% for the three and nine months ended September 30, 2021, respectively. The update reflects a change to the ratio from using the full average annual mean capacity to the net monthly mean capacity when calculating capacity factor. There is no change to actual output and the full year capacity factor would be the same under both methodologies.

ZEC Prices. We are compensated through state programs for the carbon-free attributes for certain 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 three and nine months ended September 30, 2022 and 2021.

	Three Months Ended September 30,				Nine Months Ended September 30,			
State (Region)[(a)]	2022	2021	Variance	% Change	2022	2021	Variance	% Change
New Jersey (Mid-Atlantic)	$ 10.00	$ 10.00	$ —	— %	$ 10.00	$ 10.00	$ —	— %
Illinois (Midwest)[(b)]	12.01	16.50	(4.49)	(27.2)%	14.50	16.50	(2.00)	(12.1)%
New York (New York)	21.38	21.38	—	— %	21.38	20.78	0.60	2.9 %

(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.
(b) Subject to a cap on total consideration to be received by us for each delivery period. See Note 4 — Revenue from Contracts with Customers for additional information.

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 three and nine months ended September 30, 2022, the average CMC price per MWh was a net negative value ($51.70) and ($51.85), respectively. See Note 3 - Regulatory Matters of our 2021 Form 10-K 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, depending on our net monthly position. The following tables present the average capacity reference prices ($/MW Day) for each of our major regions. Prices reflect the weighted averages for the various auction periods within the three and nine months ended September 30, 2022 and 2021.

Location (Region)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Variance	% Change	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021	Variance	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic)	$ 97.86	$ 165.73	$ (67.87)	(41.0)%	$ 135.57	$ 178.03	$ (42.46)	(23.8)%
ComEd (Midwest)	68.96	195.55	(126.59)	(64.7)%	139.29	191.42	(52.13)	(27.2)%
Rest of State (New York)	108.22	164.40	(56.18)	(34.2)%	89.67	98.47	(8.80)	(8.9)%
Southeast New England (Other)	126.67	154.37	(27.70)	(17.9)%	142.06	166.76	(24.70)	(14.8)%

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)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Variance	% Change	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021	Variance	% Change
PJM West (Mid-Atlantic)	$ 90.43	$ 41.81	$ 48.62	116.3 %	$ 74.33	$ 33.78	$ 40.55	120.0 %
ComEd (Midwest)	81.99	39.70	42.29	106.5 %	62.90	31.87	31.03	97.4 %
Central (New York)	74.96	36.29	38.67	106.6 %	60.89	26.68	34.21	128.2 %
North (ERCOT)	97.58	39.18	58.40	149.1 %	68.47	193.18	(124.71)	(64.6)%
Southeast Massachusetts (Other)[a]	86.27	43.82	42.45	96.9 %	89.01	41.18	47.83	116.1 %

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

For the three and nine months ended September 30, 2022 compared to 2021, changes in **Operating revenues** by region were approximately as follows:

	Variance	% Change[a]	Three Months Ended September 30	Variance	% Change[a]	Nine Months Ended September 30
Mid-Atlantic	$ 387	30.4 %	• favorable wholesale load revenue of $210 primarily due to higher energy prices and higher volumes • favorable retail load revenue of $180 primarily due to higher energy prices	$ 440	12.5 %	• favorable retail load revenue of $415 primarily due to higher energy prices • favorable wholesale load revenue of $100 primarily due to higher energy prices partially offset by lower volumes; partially offset by • unfavorable settled economic hedges of ($60) due to settled prices relative to hedged prices

Midwest	62	6.3 %	• favorable retail load revenue of $120 primarily due to higher energy prices; partially offset by • unfavorable net wholesale load and generation revenue of ($35) primarily due to lower cleared capacity volumes	400	13.6 %	• favorable net wholesale load and generation revenue of $460 primarily due to higher energy prices and higher volumes, partially offset by CMC program activity and lower cleared capacity volumes • favorable retail load revenue of $220 primarily due to higher energy prices; partially offset by • unfavorable settled economic hedges of ($270) due to settled prices relative to hedged prices
New York	(32)	(7.0)%	• unfavorable settled economic hedges of ($125) due to settled prices relative to hedged prices; partially offset by • favorable retail load revenue of $95 primarily due to higher energy prices and higher volumes	5	0.4 %	• favorable retail load revenue of $235 primarily due to higher energy prices and higher volumes • favorable generation revenue of $115 primarily 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 ($325) due to settled prices relative to hedged prices
ERCOT	132	36.9 %	• favorable retail load revenue of $110 primarily due to higher energy prices and higher volumes	320	36.0 %	• favorable settled economic hedges of $335 due to settled prices relative to hedged prices • favorable retail load revenue of $70 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 ($65) primarily due to lower energy prices relative to the prior year due to the February 2021 extreme cold weather event
Other Power Regions	676	53.7 %	• favorable wholesale load revenue of $340 primarily due to higher energy prices and higher volumes • favorable settled economic hedges of $180 due to settled prices relative to hedged prices • favorable retail load revenue of $135 primarily due to higher energy prices	1,460	39.2 %	• favorable wholesale load revenue of $590 primarily due to higher energy prices and higher volumes • favorable settled economic hedges of $535 due to settled prices relative to hedged prices • favorable retail load revenue of $295 primarily due to higher energy prices and higher volumes
Other	466	65.5 %	• favorable gas revenue, including settled financial hedges, of $510 primarily due to higher gas prices	1,306	46.5 %	• favorable gas revenue, including settled financial hedges, of $1,360 primarily due to higher gas prices • favorable energy revenue of $190 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 ($220)
Mark-to-market[b]	(46)		• losses on economic hedging activities of ($681) in 2022 compared to losses of ($635) in 2021	(941)		• losses on economic hedging activities of ($1,899) in 2022 compared to losses of ($958) in 2021
Total	$ 1,645	37.3 %		$ 2,990	34.6 %	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 12 — 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: 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 three and nine months ended September 30, 2022 compared to 2021, Purchased power and fuel by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2022	2021	Variance	% Change[(a)]	2022	2021	Variance	% Change[(a)]
Mid-Atlantic	$ 1,104	$ 702	$ (402)	(57.3)%	$ 2,355	$ 1,815	$ (540)	(29.8) %
Midwest	475	330	(145)	(43.9)%	1,335	930	(405)	(43.5) %
New York	156	109	(47)	(43.1)%	351	293	(58)	(19.8) %
ERCOT	424	179	(245)	(136.9)%	975	1,812	837	46.2 %
Other Power Regions	1,679	1,049	(630)	(60.1)%	4,479	3,165	(1,314)	(41.5) %
Total electric purchased power and fuel	3,838	2,369	(1,469)	(62.0)%	9,495	8,015	(1,480)	(18.5) %
Other	1,014	566	(448)	(79.2)%	3,587	2,288	(1,299)	(56.8) %
Mark-to-market gains	(157)	(1,389)	(1,232)		(1,328)	(2,200)	(872)	
Total purchased power and fuel	$ 4,695	$ 1,546	$ (3,149)	(203.7)%	$ 11,754	$ 8,103	$ (3,651)	(45.1) %

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

For the three and nine months ended September 30, 2022 compared to 2021, changes in **Purchased power and fuel** by region were approximately as follows:

	Variance	% Change[(a)]	Three Months Ended September 30	Variance	% Change[(a)]	Nine Months Ended September 30
Mid-Atlantic	$ (402)	(57.3) %	• unfavorable purchased power and net capacity impact of ($400) primarily due to higher energy prices, lower capacity prices earned and lower nuclear generation	$ (540)	(29.8) %	• unfavorable purchased power and net capacity impact of ($565) primarily due to higher energy prices, lower nuclear generation, and lower capacity prices earned; partially offset by • favorable settlement of economic hedges of $40 due to settled prices relative to hedged prices
Midwest	(145)	(43.9) %	• unfavorable purchased power and net capacity impact of ($160) primarily due to higher energy prices and lower capacity prices earned	(405)	(43.5) %	• unfavorable purchased power and net capacity impact of ($485) primarily due to higher energy prices, higher load, and lower capacity prices earned; partially offset by • favorable nuclear fuel cost of $80 primarily due to accelerated amortization of nuclear fuel in prior periods

New York	(47)	(43.1)%	• unfavorable purchased power and net capacity impact of ($40) primarily due to higher energy prices, higher load, and lower capacity prices earned	(58)	(19.8)%	• unfavorable purchased power and net capacity impact of ($140) primarily due to higher energy prices, higher load, and lower nuclear generation; partially offset by • favorable settlement of economic hedges of $90 due to settled prices relative to hedged prices
ERCOT	(245)	(136.9)%	• unfavorable purchased power of ($110) primarily due to higher energy prices, higher load, and absence of favorable recovery related to the February 2021 extreme cold weather event • unfavorable settlement of economic hedges of ($105) due to settled prices relative to hedged prices • unfavorable fuel cost of ($30) primarily due to higher gas prices relative to the prior year	837	46.2 %	• favorable purchased power of $590 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 $155 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	(630)	(60.1)%	• unfavorable purchased power and net capacity impact of ($635) primarily due to higher energy prices and higher load • unfavorable fuel cost of ($120) primarily due to higher gas prices; partially offset by • unfavorable environmental product optimization of ($60); partially offset by • favorable settlement of economic hedges of $200 due to settled prices relative to hedged prices	(1,314)	(41.5)%	• unfavorable purchased power and net capacity impact of ($1,775) primarily due to higher energy prices, higher load, lower generation and lower cleared capacity volumes • unfavorable fuel cost of ($340) primarily due to higher gas prices • unfavorable environmental product optimization of ($80); partially offset by • favorable settlement of economic hedges of $900 due to settled prices relative to hedged prices
Other	(448)	(79.2)%	• unfavorable net gas purchase costs and settlement of economic hedges of ($465)	(1,299)	(56.8)%	• unfavorable net gas purchase costs and settlement of economic hedges of ($1,545) • unfavorable energy purchases of ($155) primarily due to higher energy prices • unfavorable fair value adjustment related to gas imbalances of ($100); partially offset by • favorable impact due to the absence of LDC and pipeline penalties due to the February 2021 extreme cold weather event of $330 • favorable impact due to the absence of accelerated nuclear fuel amortization associated with announced early plant retirements of $150
Mark-to-market[b]	(1,232)		• gains on economic hedging activities of $157 in 2022 compared to gains of $1,389 in 2021	(872)		• gains on economic hedging activities of $1,328 in 2022 compared to gains of $2,200 in 2021
Total	$ (3,149)	(203.7)%		$ (3,651)	(45.1)%	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

For the three and nine months ended September 30, 2022 compared to 2021, changes in **Operating and maintenance expense** consisted of the following:

	Three Months Ended September 30	Nine Months Ended September 30
	(Decrease) Increase	(Decrease) Increase
Labor, contracting, and materials[(a)]	$ 153	$ 180
Plant retirements and divestitures[(b)]	94	88
Separation costs[(c)]	14	56
Credit loss expense[(d)]	(1)	(45)
COVID-19 direct costs	(5)	(24)
Nuclear refueling outage costs, including the co-owned Salem generating units	(17)	59
Asset impairments	(45)	(537)
Prior merger commitment[(e)]	(50)	(50)
Decommissioning-related activities[(f)]	(99)	287
Other	7	39
Total (decrease) increase	$ 51	$ 53

(a) Primarily reflects increased employee-related costs, including labor, stock-based compensation, and other incentives, etc.
(b) Reflects the absence of the reversal of charges recorded in the third quarter of 2021 associated with the reversal of the previous decision to early retire Byron and Dresden.
(c) 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.
(d) Primarily a result of the February 2021 extreme cold weather event.
(e) Reversal of a charge related to a prior merger commitment.
(f) 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 our 2021 Form 10-K for additional information.

Depreciation and amortization expense decreased for the three and nine months ended September 30, 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.

Taxes other than income taxes increased for the three and nine months ended September 30, 2022 compared to the same period in 2021, primarily due to increased gross receipt tax related to our retail operations. The offsetting collection of gross receipts tax related to our retail operations is recorded in Operating revenues.

(Loss) gain on sales of assets and businesses decreased for the three and nine months ended September 30, 2022 compared to the same period in 2021, primarily due to gains on sales of equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021 and a gain on sale of our solar business in 2021.

Interest expense, net decreased for the three and nine months ended September 30, 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 our 2021 Form 10-K for additional information on the CR credit facility and interest rate swaps.

Other, net decreased for the three and nine months ended September 30, 2022 compared to the same period in 2021, due to activity described in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	2022	2021
Net unrealized (losses) gains on NDT funds[(a)]	$ (225)	$ (94)	$ (1,077)	$ 33
Net realized (losses) gains on sale of NDT funds[(a)]	(7)	101	45	349
Interest and dividend income on NDT funds[(a)]	22	26	70	73
Contractual elimination of income tax expense[(b)]	(63)	11	(284)	150
Non-service net periodic benefit credit[(c)]	27	—	79	—
Net unrealized (losses) gains from CTV investments[(d)]	(2)	(179)	(27)	(83)
Return to provision adjustment[(e)]	26	—	(32)	—
TSA billings[(f)]	12	—	32	—
Other	14	20	25	39
Total Other, net	$ (196)	$ (115)	$ (1,169)	$ 561

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(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 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 (costs) 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 11 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.
(d) Net unrealized gains and losses from CTV investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.
(e) This reflects amounts contractually owed to Exelon under the tax matters agreement, which is offset in Income taxes. See Note 10 - 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 39.4% and 21.7% for the three months ended September 30, 2022 and 2021, respectively, and 73.1% and (1350.0)% for the nine months ended September 30, 2022 and 2021, respectively. The 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 10 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Net income attributable to noncontrolling interests primarily relates to CRP for the three and nine months ended September 30, 2022 and includes CENG and CRP for the same period in 2021. The decrease for the three and nine months ended September 30, 2022, compared to 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 our 2021 Form 10-K for additional information.

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. We incurred separation costs of $30 million and $99 million for the three and nine months ended September 30, 2022, respectively, which are primarily recorded in Operating and maintenance expense. Separation costs for the three and nine months ended September 30, 2021 were not material. 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. These costs have been excluded from Adjusted EBITDA (non-GAAP). See Note 1 — Basis of Presentation of the Combined Notes to Consolidated Financial Statements for additional information.

Other Key Business Drivers

Power Markets

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 therefore, we have enough nuclear fuel to support all our refueling needs for multiple years regardless of sanctions. We are taking 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. We are also working 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 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 September 30, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 92%-95% for 2022 and 2023, respectively. We have been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

We procure natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Approximately 55% of our uranium concentrate requirements from 2022 through 2026 are supplied by three suppliers. In the event of non-performance by these or other suppliers, we believe that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Geopolitical developments have the potential to impact delivery from multiple suppliers in the international uranium processing industry. Non-performance by these counterparties could have a material adverse impact on our consolidated financial statements.

See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements and ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Other Environmental Regulation

Federal Climate Change Legislation and Regulation. On August 16, 2022, 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/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.

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 Supreme Court granted certiorari to examine the extent of EPA's authority to regulate GHGs from power plants. The electric utilities coalition filed a brief and participated in oral argument before the Supreme Court. On June 30, 2022, the Supreme Court issued a decision holding that 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 EPA has indicated it will promulgate new GHG limits for existing power plants in March 2023.

State Climate Change Legislation and Regulation. On July 1, 2022, Pennsylvania formally began participation in the 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 CO2 emissions. Non-emitting resources do not have to purchase or hold these allowances. The process of bringing Pennsylvania into the RGGI began in October 2019 when the Governor of Pennsylvania signed an Executive Order directing the PA DEP to commence the rulemaking to join the RGGI and that rule went into effect with Pennsylvania joining RGGI on July 1, 2022. However, on July 8, 2022, the Commonwealth Court of Pennsylvania entered two preliminary injunctions preventing Pennsylvania from participating in RGGI while ongoing legal challenges proceed. At least one of those injunctions currently remains in place while it is appealed to the Pennsylvania Supreme Court, where briefing of the appeal will be completed by December 4, 2022. In addition, the Commonwealth Court of Pennsylvania is scheduled to hear oral arguments in November 2022 on the merits of the challenges to Pennsylvania entering RGGI. On September 26, the Virginia State Air Pollution Control Board published a Notice of Intended Regulatory Action to begin the process for repealing "Regulation for Emissions Trading," which implemented Virginia's participation in RGGI. The Virginia Department of Environmental Quality was directed to reevaluate Virginia's participation in RGGI and begin a regulatory process to end it per a governor's order.

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 coal- and oil-fired 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. This rule has been subject to various challenges since issuance, see PART I, ITEM 1. BUSINESS of our 2021 Form 10-K for additional information on the procedural history of this matter. 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 U.S. Court of Appeals 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 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 U.S. Court of Appeals for the D.C. Circuit granted unopposed motions to substitute Constellation in place of Exelon in these cases. Comments on the proposed regulation were due April 11, 2022. If EPA promulgates a final rule revoking the 2020 revised supplemental finding determination, then the cases currently before the U.S. Court of Appeals for 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.

Critical Accounting Policies and Estimates

Management makes a number of significant estimates, assumptions, and judgements in the preparation of our financial statements. The following policy was added as a result of separation. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in our 2021 Form 10-K for further information.

Retirement Benefits

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, and hedge funds.

Expected Rate of Return on Plan Assets. 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. 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. In 2022, we adopted the revised 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 on the remeasurement completed at separation as discussed in Note 11 — 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 2022 cost:						
Discount rate[(a)]	3.23 %	3.21 %	0.5 %	$ (22)	$ (1)	$ (23)
	3.23 %	3.21 %	(0.5) %	28	7	35
EROA	7.00 %	6.50 %	0.5 %	(41)	(4)	(45)
	7.00 %	6.50 %	(0.5) %	41	4	45
Change in benefit obligation:						
Discount rate[(a)]	3.23 %	3.21 %	0.5 %	(536)	(99)	(635)
	3.23 %	3.21 %	(0.5) %	620	115	735

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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 11 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension and OPEB plans.

Liquidity and Capital Resources

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 various facilities with aggregate bank commitments of $5.8 billion. We utilize these facilities to support our commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the “Credit Matters” section below for additional information. We expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 13 — 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 8 — Nuclear Decommissioning 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 September 30, 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. An additional exemption request to allow the TMI Unit 1 NDT funds to be used for site restoration costs was submitted to the NRC on May 20, 2021. 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 15 — 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 nine months ended September 30, 2022 and 2021:

Increase (decrease) in cash flows from operating activities	
Net loss	$ (73)
Adjustments to reconcile net income to cash:	
Collateral received, net	(1,208)
Changes in working capital and other noncurrent assets and liabilities	(617)
Pension and non-pension postretirement benefit contributions	8
Option premiums paid, net	23
Income taxes	187
Other non-cash operating activities	775
Decrease in cash flows from operating activities	$ (905)

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 the nine months ended September 30, 2022 and 2021 were as follows:

- 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 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral.

- **Changes in working capital and other noncurrent assets and liabilities** primarily reflect reduced DPP consideration related to the revolving accounts receivable financing arrangement entered into on April 8, 2020, a decrease in Accounts payable resulting from the impact of certain penalties for natural gas delivery associated with the February 2021 extreme cold weather event, increased inventory due to rising gas prices and decreased sales of emissions allowances. There is a partial offset for this decrease due to increases in Accounts payable related to rising gas prices and the Illinois CMC program, and reimbursements of costs associated with the storage of SNF. Additionally, there is a partial offset for this decrease in Cash Flows from Investing activities due to cash proceeds received from the Purchasers during the first quarter of 2021. See Note 6 — Accounts Receivable and Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the sales of customer accounts receivable and on the February 2021 extreme cold weather event, respectively and Note 19 — Commitments and Contingencies of our 2021 Form 10-K for additional information on the storage of SNF.

- See Note 10 — Income Taxes of the Combined Notes to Consolidated Financial Statements and the Consolidated Statements of Cash Flows for additional information on **income taxes**.

- See Note 19 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Consolidated Statements of Cash Flows for additional information on **non-cash operating activities**.

Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the nine months ended September 30, 2022 and 2021:

(Decrease) increase in cash flows from investing activities	
Proceeds from sales of assets and businesses	(761)
Investment in NDT funds, net	(44)
Capital expenditures	(4)
Collection of DPP, net	43
Other investing activities	(2)
Decrease in cash flows from investing activities	$ (768)

Significant investing cash flow impact for the nine months ended September 30, 2022 and 2021 was as follows:

- **Proceeds from sales of assets and businesses** decreased primarily due to the sale of a significant portion of our solar business and a biomass facility 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.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the nine months ended September 30, 2022 and 2021:

(Decrease) increase in cash flows from financing activities		
Contribution from Exelon	$	1,686
Distributions to Exelon		1,373
Acquisition of CENG noncontrolling interest		885
Changes in money pool with Exelon		285
Dividends paid on common stock		(139)
Long-term debt, net		(1,455)
Changes in short-term borrowings, net		(1,929)
Other financing activities		2
Increase in cash flows from financing activities	$	708

Significant financing cash flow impacts for the nine months ended September 30, 2022 and 2021 were as follows:

- **Contribution from Exelon** is 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.
- **Distributions to Exelon** relate 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.
- 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.
- **Changes 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.
- **Long-term debt, net,** varies due to debt issuances and redemptions each year. Refer to Note 13 - Debt and Credit Agreements 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 13 - Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings.

Dividends

Quarterly dividends declared by our Board of Directors during the nine months ended September 30, 2022 and for the third quarter of 2022 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

Credit Matters and Cash Requirements

We fund liquidity needs for capital expenditures, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. As of September 30, 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 the third quarter of 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 of our 2021 Form 10-K for additional information regarding the effects of uncertainty in the capital and credit markets.

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

If we lost our investment grade credit rating as of September 30, 2022, we would have been required to provide incremental collateral estimated to be approximately $3.1 billion to meet collateral obligations for derivatives, non-derivatives, NPNS, and applicable payables and receivables, net of the contractual right of offset under master netting agreements. As of September 30, 2022, we had $2.2 billion of available capacity and $1.2 billion of cash on hand. In the event of a credit downgrade that required us to provide incremental collateral exceeding our available capacity, we would be required to access additional liquidity through the capital markets. See Note 12 — Derivative Financial Instruments and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

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 of 2006 (the Act), and management of the pension obligation. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The contributions below reflect a funding strategy to make levelized annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This level funding strategy helps minimize 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. Unlike the qualified pension plans, our non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, we do fund certain of our plans. For our funded OPEB plans, contributions generally equal accounting costs; however, we consider several factors in determining the level of contributions to our OPEB plans, including liabilities management and levels of benefit claims paid. The estimated benefit payments to the non-qualified pension plans in 2022 are $21 million and the planned contributions to the OPEB plans, including estimated benefit payments to unfunded plans is $27 million. The benefit payments to the non-qualified pension plans and OPEB plans for the nine months ended September 30, 2022 were $16 million and $21 million, respectively.

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 11 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on pension and OPEB contributions.

Cash Requirements for Other Financial Commitments

Refer to Liquidity and Capital Resources of our 2021 Form 10-K for additional information on our cash requirements for financial commitments.

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 our 2021 Form 10-K for additional information on our project finance structures 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our credit facilities.

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 facility 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 12 — 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. We have only engaged S&P and Moody's for ratings coverage following separation. Subsequently, on October 13, 2022, S&P raised our senior unsecured debt rating to 'BBB' from 'BBB-' citing the passage of the IRA of 2022 as a material credit positive for us.

ITEM 3. 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. The following discussion serves as an update to ITEM 7A - QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of our 2021 Annual Report on Form 10-K incorporated herein by reference.

Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental, regulatory and environmental policies, and other factors. To the extent the total amount of energy we generate and purchase differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in commodity prices. We seek to mitigate our commodity price risk through the sale and purchase of electricity, 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 2022 through 2024.

As of September 30, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 97%-100% and 92%-95% for 2022 and 2023, respectively. 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 $2.50/MWh reduction in the annual average around-the-clock energy price based on September 30, 2022 market conditions and hedged position would be a decrease in pre-tax net income of approximately $3 million and $32 million for 2022 and 2023, respectively. See Note 12 — 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 55% of our uranium concentrate requirements from 2022 through 2026 are supplied by three suppliers. To-date we have not experienced any counterparty credit risk associated with these suppliers stemming from the Russia 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 processing industry. Non-performance by these counterparties could have a material adverse impact on 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.

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, 2021 to September 30, 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 12 — 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 September 30, 2022 and December 31, 2021.

	Mark-to-market Energy Contract Net Assets (Liabilities)
Balance as of December 31, 2021	$ 1,622 (a)
Total change in fair value during 2022 of contracts recorded in result of operations	698
Reclassification to realized at settlement of contracts recorded in results of operations	(1,270)
Changes in allocated collateral	(745)
Net option premium paid	163
Option premium amortization	(239)
Upfront payments and amortizations(b)	(108)
Foreign currency translation	23
Balance as of September 30, 2022	$ 144 (a)

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

Fair Values

The following table presents maturity and source of fair value for mark-to-market commodity contract net assets (liabilities). The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of our total mark-to-market net assets (liabilities), net of allocated collateral. Second, the table shows the maturity, by year, of our commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 14 — 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						
	2022	2023	2024	2025	2026	2027 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ 494	$ 487	$ 291	$ 144	$ 67	$ 27	$ 1,510
Prices provided by external sources (Level 2)	(335)	772	(278)	(79)	7	—	87
Prices based on model or other valuation methods (Level 3)	(500)	(689)	(43)	(100)	(70)	(51)	(1,453)
Total	$ (341)	$ 570	$ (30)	$ (35)	$ 4	$ (24)	$ 144

(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 ($235) million at September 30, 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 12 — 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 September 30, 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 amounts in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, and commodity exchanges, which are discussed in ITEM 7A - QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of our 2021 Annual Report on Form 10-K .

Rating as of September 30, 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	$ 1,515	$ 584	$ 931	—	$ —
Non-investment grade	14	—	14	—	—
No external ratings					
Internally rated—investment grade	109	—	109	—	—
Internally rated—non-investment grade	330	89	241	—	—
Total	$ 1,968	$ 673	$ 1,295	—	$ —

(a) As of September 30, 2022, credit collateral held from counterparties where we had credit exposure included $530 million of cash and $143 million of letters of credit.

Rating as of September 30, 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	$ 1,348	$ 114	$ 53	$ 1,515
Non-investment grade	14	—	—	14
No external ratings				
Internally rated—investment grade	109	—	—	109
Internally rated—non-investment grade	283	40	7	330
Total	$ 1,754	$ 154	$ 60	$ 1,968

Net Credit Exposure by Type of Counterparty	As of September 30, 2022	
Investor-owned utilities, marketers, power producers	$	1057
Energy cooperatives and municipalities		96
Financial institutions		53
Other		89
Total	$	1,295

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 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements and Note 15 — 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 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. In addition, we entered into supply forward contracts with certain utilities with one-sided collateral postings only from us. To post collateral, we depend on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

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 nine months ended September 30, 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 12 — 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 $678 million reduction in the fair value of the trust assets as of September 30, 2022. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices.

ITEM 4. CONTROLS AND PROCEDURES

During the third 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 with the SEC. These disclosure controls and procedures have been designed to ensure that (a) information, including information related 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, evaluated, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of September 30, 2022, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives. 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 were no changes in internal control over financial reporting during the third quarter of 2022 that materially affected, or are reasonably likely to materially affect, any of our internal controls over financial reporting.

PART II. OTHER INFORMATION

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

ITEM 1. 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 15 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this report. Such descriptions are incorporated herein by these references.

ITEM 1A. RISK FACTORS

At September 30, 2022, our risk factors were consistent with the risk factors described in our 2021 Form 10-K in ITEM 1A. RISK FACTORS.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
3.1	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).
10.1	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).
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith.

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2022 filed by the following officers for the following companies:

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 (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2022 filed by the following officers for the following companies:

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

SIGNATURES

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

CONSTELLATION ENERGY CORPORATION

/s/ JOSEPH DOMINGUEZ	/s/ DANIEL L. EGGERS
Joseph Dominguez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 8, 2022

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

CONSTELLATION ENERGY GENERATION, LLC

/s/ JOSEPH DOMINGUEZ	/s/ DANIEL L. EGGERS
Joseph Dominguez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 8, 2022