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, 2025
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 Energy 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 October 31, 2025 was as follows:

Constellation Energy Corporation Common Stock, without par value	312,290,080
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
Registrants	CEG Parent and Constellation, collectively
Antelope Valley	Antelope Valley Solar Ranch One
Continental Wind	Continental Wind LLC
CR	Constellation Renewables, LLC
Crane	Crane Clean Energy Center (formerly known as Three Mile Island Unit 1)
CRP	Constellation Renewables Partners, LLC
NER	NewEnergy Receivables LLC
RPG	Renewable Power Generation, LLC
STP	South Texas Project nuclear generating station
West Medway II	West Medway Generating Station II

Former Related Entities

Exelon	Exelon Corporation
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

AEP Texas	American Electric Power Texas
AESO	Alberta Electric Systems Operator
AOCI	Accumulated Other Comprehensive Income (Loss)
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASR	Accelerated Share Repurchase
CAISO	California ISO
CenterPoint	CenterPoint Energy Houston Electric, LLC
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CMC	Carbon Mitigation Credit
CODM	Chief Operating Decision Maker
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
ERP	Enterprise Resource Planning
Exchange Act	Securities Exchange Act of 1934, as amended
FERC	Federal Energy Regulatory Commission
Former PECO Units	Limerick, Peach Bottom, and Salem nuclear generating units
Former ComEd Units	Braidwood, Byron, Dresden, LaSalle and Quad Cities nuclear generating units
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt hour
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITC	Investment Tax Credit
MDE	Maryland Department of the Environment
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody’s Investors Service, Inc.
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
NASDAQ	Nasdaq Stock Market, LLC

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
OBBBA	One Big Beautiful Bill Act of 2025
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
Pension Protection Act	Pension Protection Act of 2006
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
PPA	Power Purchase Agreement
PP&E	Property, Plant, and Equipment
PSDAR	Post-shutdown Decommissioning Activities Report
PSEG	Public Service Enterprise Group Incorporated
PTC	Production Tax Credit
PUCT	Public Utility Commission of Texas
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting (includes the Former ComEd Units, the Former PECO Units and STP)
RNF	Operating Revenues Net of Purchased Power and Fuel Expense
RTO	Regional Transmission Organization
S&P	S&P Global Ratings, a Standard & Poor's Financial Services LLC business
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOFR	Secured Overnight Financing Rate
SPP	Southwest Power Pool
STPNOC	STP Nuclear Operating Company
TMA	Tax Matters Agreement
TWh	Terawatt-hour
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
U.S. Treasury	U.S. Department of the Treasury
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit

FILING FORMAT

This combined Form 10-Q is being filed separately by Constellation Energy Corporation and Constellation Energy Generation, LLC, (the 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. These forward-looking statements include, but are not limited to, statements regarding the proposed transaction between Constellation and Calpine Corporation, the expected closing of the proposed transaction and the timing thereof. This includes statements regarding the financing of the proposed transaction and the pro forma combined company and its operations, strategies and plans, enhancements to investment-grade credit profile, synergies, opportunities and anticipated future performance and capital structure, and expected accretion to earnings per share and free cash flow. Information adjusted for the proposed transaction should not be considered a forecast of future results.

Forward-looking statements are based on current expectations, estimates and assumptions that involve a number of risks and uncertainties that could cause actual results to differ materially from those projected. 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 2024 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 18 — 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 14 — 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 Registrant undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this report.

AVAILABLE 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. We file our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports with the SEC. In addition, as soon as reasonably practicable after such materials are furnished to the SEC, we make copies of these documents available to the public free of charge through our website 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, 2025	Three Months Ended September 30, 2024	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
Operating revenues	$ 6,570	$ 6,550	$ 19,459	$ 18,186
Operating expenses				
Purchased power and fuel	3,567	3,119	11,083	8,828
Operating and maintenance	1,511	1,535	4,673	4,666
Depreciation and amortization	241	266	743	868
Taxes other than income taxes	165	165	472	446
Total operating expenses	5,484	5,085	16,971	14,808
Gain (loss) on sales of assets and businesses	—	2	—	2
Operating income (loss)	1,086	1,467	2,488	3,380
Other income and (deductions)				
Interest expense, net	(134)	(147)	(398)	(416)
Other, net	443	325	729	693
Total other income and (deductions)	309	178	331	277
Income (loss) before income taxes	1,395	1,645	2,819	3,657
Income tax (benefit) expense	466	449	928	768
Equity in income (losses) of unconsolidated affiliates	—	—	—	(1)
Net income (loss)	929	1,196	1,891	2,888
Net income (loss) attributable to noncontrolling interests	(1)	(4)	4	(9)
Net income (loss) attributable to common shareholders	$ 930	$ 1,200	$ 1,887	$ 2,897
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 929	$ 1,196	$ 1,891	$ 2,888
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(1)	(1)	(3)	(3)
Actuarial loss reclassified to periodic cost	19	15	54	53
Pension and non-pension postretirement benefit plan valuation adjustment	—	—	(34)	(4)
Unrealized gain (loss) on cash flow hedges	2	1	5	3
Unrealized gain (loss) on foreign currency translation	(8)	12	20	8
Other comprehensive income (loss), net of income taxes	12	27	42	57
Comprehensive income (loss)	941	1,223	1,933	2,945
Comprehensive income (loss) attributable to noncontrolling interests	(1)	(4)	4	(9)
Comprehensive income (loss) attributable to common shareholders	$ 942	$ 1,227	$ 1,929	$ 2,954
Average shares of common stock outstanding:				
Basic	313	313	313	315
Assumed exercise and/or distributions of stock-based awards	—	1	1	1
Diluted	313	314	314	316
Earnings per average common share				
Basic	$ 2.98	$ 3.83	$ 6.02	$ 9.20
Diluted	$ 2.97	$ 3.82	$ 6.02	$ 9.17

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
Cash flows from operating activities		
Net income (loss)	$ 1,891	$ 2,888
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,945	2,049
Deferred income taxes and amortization of ITCs	248	358
Net fair value changes related to derivatives	328	(1,161)
Net realized and unrealized (gains) losses on NDT funds	(588)	(475)
Net realized and unrealized (gains) losses on equity investments	256	115
Other non-cash operating activities	(74)	(161)
Changes in assets and liabilities:		
Accounts receivable	(184)	1,083
Inventories	(62)	31
Accounts payable and accrued expenses	(25)	(38)
Option premiums received (paid), net	49	159
Collateral received (posted), net	(192)	1,495
Income taxes	423	154
Pension and non-pension postretirement benefit contributions	(193)	(178)
Other assets and liabilities	(390)	(7,767)
Net cash flows provided by (used in) operating activities	3,432	(1,448)
Cash flows from investing activities		
Capital expenditures	(1,963)	(1,836)
Proceeds from NDT fund sales	5,525	4,934
Investment in NDT funds	(5,773)	(5,140)
Collection of DPP, net	—	7,104
Acquisitions of assets and businesses	(13)	(22)
Other investing activities	3	16
Net cash flows provided by (used in) investing activities	(2,221)	5,056
Cash flows from financing activities		
Change in short-term borrowings	—	(1,105)
Proceeds from short-term borrowings with maturities greater than 90 days	1,650	200
Repayments of short-term borrowings with maturities greater than 90 days	—	(739)
Issuance of long-term debt	—	900
Retirement of long-term debt	(1,036)	(99)
Dividends paid on common stock	(365)	(333)
Repurchases of common stock	(400)	(999)
Other financing activities	(98)	(5)
Net cash flows provided by (used in) financing activities	(249)	(2,180)
Increase (decrease) in cash, restricted cash, and cash equivalents	962	1,428
Cash, restricted cash, and cash equivalents at beginning of period	3,129	454
Cash, restricted cash, and cash equivalents at end of period	$ 4,091	$ 1,882
Supplemental disclosure of non-cash investing and financing activities		
Increase (decrease) in DPP	$ —	$ 7,682
Increase (decrease) in PP&E related to ARO update	188	(1,475)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2025	December 31, 2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,959	$ 3,022
Restricted cash and cash equivalents	132	107
Accounts receivable, net		
Customer accounts receivable (net of allowance for credit losses of $190 as of September 30, 2025 and December 31, 2024)	3,168	3,116
Other accounts receivable (net of allowance for credit losses of $8 and $6 as of September 30, 2025 and December 31, 2024, respectively)	612	602
Mark-to-market derivative assets	632	843
Inventories, net		
Natural gas, oil, and emission allowances	242	243
Materials and supplies	1,422	1,357
Renewable energy credits	786	797
Other	696	689
Total current assets	11,649	10,776
Property, plant, and equipment (net of accumulated depreciation and amortization of $18,932 and $18,088 as of September 30, 2025 and December 31, 2024, respectively)	21,990	21,235
Deferred debits and other assets		
Nuclear decommissioning trust funds	18,985	17,305
Investments	427	640
Goodwill	420	420
Mark-to-market derivative assets	459	372
Other	2,231	2,178
Total deferred debits and other assets	22,522	20,915
Total assets[(a)]	$ 56,161	$ 52,926

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2025	December 31, 2024
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 1,650	$ —
Long-term debt due within one year	118	1,028
Accounts payable and accrued expenses	3,926	3,943
Mark-to-market derivative liabilities	474	467
Renewable energy credit obligation	956	1,076
Other	331	332
Total current liabilities	7,455	6,846
Long-term debt	7,269	7,384
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,578	3,331
Asset retirement obligations	13,032	12,449
Pension and non-pension postretirement benefit obligations	1,767	1,875
Spent nuclear fuel obligation	1,412	1,366
Payables related to Regulatory Agreement Units	5,222	4,518
Mark-to-market derivative liabilities	440	399
Other	1,294	1,219
Total deferred credits and other liabilities	26,745	25,157
Total liabilities[(a)]	41,469	39,387
Commitments and contingencies (Note 14)		
Shareholders' equity		
Common stock (No par value, 1,000 shares authorized, 312 and 313 shares outstanding as of September 30, 2025 and December 31, 2024, respectively)	11,022	11,402
Retained earnings (deficit)	5,588	4,066
Accumulated other comprehensive income (loss), net	(2,260)	(2,302)
Total shareholders' equity	14,350	13,166
Noncontrolling interests	342	373
Total equity	14,692	13,539
Total liabilities and shareholders' equity	$ 56,161	$ 52,926

(a) Our consolidated assets include $4,358 million and $4,318 million at September 30, 2025 and December 31, 2024, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $925 million and $968 million at September 30, 2025 and December 31, 2024, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 16 — Variable Interest Entities for additional information.

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, 2025					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2024	312,838	$ 11,402	$ 4,066	$ (2,302)	$ 373	$ 13,539
Net Income (loss)	—	—	118	—	11	129
Employee incentive plans	547	(49)	—	—	—	(49)
Changes in equity of noncontrolling interests	—	—	—	—	(6)	(6)
Common stock dividends ($0.3878/common share)	—	—	(122)	—	—	(122)
Capped call option contracts	—	(150)	—	—	—	(150)
Other comprehensive income (loss), net of income taxes	—	—	—	(7)	—	(7)
Balance, March 31, 2025	313,385	$ 11,203	$ 4,062	$ (2,309)	$ 378	$ 13,334
Net Income (loss)	—	—	839	—	(6)	833
Employee incentive plans	117	37	—	—	—	37
Changes in equity of noncontrolling interests	—	—	—	—	(15)	(15)
Common stock dividends ($0.3878/common share)	—	—	(122)	—	—	(122)
Common stock repurchased	(1,099)	(404)	—	—	—	(404)
Capped call option contracts	—	103	—	—	—	103
Other comprehensive income (loss), net of income taxes	—	—	—	37	—	37
Balance, June 30, 2025	312,403	$ 10,939	$ 4,779	$ (2,272)	$ 357	$ 13,803
Net Income (loss)	—	—	930	—	(1)	929
Employee incentive plans	58	30	—	—	—	30
Changes in equity of noncontrolling interests	—	—	—	—	(14)	(14)
Common stock dividends ($0.3878/common share)	—	—	(121)	—	—	(121)
Common stock repurchased	(183)	—	—	—	—	—
Capped call option contracts	—	53	—	—	—	53
Other comprehensive income (loss), net of income taxes	—	—	—	12	—	12
Balance, September 30, 2025	312,278	$ 11,022	$ 5,588	$ (2,260)	$ 342	$ 14,692

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, 2024					
	Shareholders' Equity					
(In millions, shares in thousands)	Issued Shares	Common Stock	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2023	317,472	$ 12,355	$ 761	$ (2,191)	$ 361	$ 11,286
Net Income (loss)	—	—	883	—	—	883
Employee incentive plans	661	(4)	—	—	—	(4)
Common stock dividends ($0.3525/common share)	—	—	(112)	—	—	(112)
Common stock repurchased	(2,900)	(504)	—	—	—	(504)
Other comprehensive income (loss), net of income taxes	—	—	—	11	—	11
Balance, March 31, 2024	315,233	$ 11,847	$ 1,532	$ (2,180)	$ 361	$ 11,560
Net Income (loss)	—	—	814	—	(5)	809
Employee incentive plans	72	8	—	—	—	8
Common stock dividends ($0.3525/common share)	—	—	(110)	—	—	(110)
Common stock repurchased	(2,091)	(505)	—	—	—	(505)
Other comprehensive income (loss), net of income taxes	—	—	—	19	—	19
Balance, June 30, 2024	313,214	$ 11,350	$ 2,236	$ (2,161)	$ 356	$ 11,781
Net Income (loss)	—	—	1,200	—	(4)	1,196
Employee incentive plans	78	29	—	—	—	29
Changes in equity of noncontrolling interests	—	—	—	—	19	19
Common stock dividends ($0.3525/common share)	—	—	(111)	—	—	(111)
Common stock repurchased	(528)	—	—	—	—	—
Other comprehensive income, net of income taxes	—	—	—	27	—	27
Balance, September 30, 2024	312,764	$ 11,379	$ 3,325	$ (2,134)	$ 371	$ 12,941

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, 2025	Three Months Ended September 30, 2024	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
Operating revenues	$ 6,570	$ 6,550	$ 19,459	$ 18,186
Operating expenses				
Purchased power and fuel	3,567	3,119	11,083	8,828
Operating and maintenance	1,511	1,535	4,673	4,666
Depreciation and amortization	241	266	743	868
Taxes other than income taxes	165	165	472	446
Total operating expenses	5,484	5,085	16,971	14,808
Gain (loss) on sales of assets and businesses	—	2	—	2
Operating income (loss)	1,086	1,467	2,488	3,380
Other income and (deductions)				
Interest expense, net	(134)	(147)	(398)	(416)
Other, net	443	325	729	693
Total other income and (deductions)	309	178	331	277
Income (loss) before income taxes	1,395	1,645	2,819	3,657
Income tax (benefit) expense	466	449	928	768
Equity in income (losses) of unconsolidated affiliates	—	—	—	(1)
Net income (loss)	929	1,196	1,891	2,888
Net income (loss) attributable to noncontrolling interests	(1)	(4)	4	(9)
Net income (loss) attributable to membership interest	$ 930	$ 1,200	$ 1,887	$ 2,897
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 929	$ 1,196	$ 1,891	$ 2,888
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(1)	(1)	(3)	(3)
Actuarial loss reclassified to periodic cost	19	15	54	53
Pension and non-pension postretirement benefit plan valuation adjustment	—	—	(34)	(4)
Unrealized gain (loss) on cash flow hedges	2	1	5	3
Unrealized gain (loss) on foreign currency translation	(8)	12	20	8
Other comprehensive income (loss), net of income taxes	12	27	42	57
Comprehensive income (loss)	941	1,223	1,933	2,945
Comprehensive income (loss) attributable to noncontrolling interests	(1)	(4)	4	(9)
Comprehensive income (loss) attributable to membership interest	$ 942	$ 1,227	$ 1,929	$ 2,954

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, 2025	Nine Months Ended September 30, 2024
Cash flows from operating activities		
Net income (loss)	$ 1,891	$ 2,888
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	1,945	2,049
Deferred income taxes and amortization of ITCs	248	358
Net fair value changes related to derivatives	328	(1,161)
Net realized and unrealized (gains) losses on NDT funds	(588)	(475)
Net realized and unrealized (gains) losses on equity investments	256	115
Other non-cash operating activities	(139)	(195)
Changes in assets and liabilities:		
Accounts receivable	(201)	1,085
Receivables from and payables to affiliates, net	(51)	238
Inventories	(62)	31
Accounts payable and accrued expenses	(36)	(38)
Option premiums received (paid), net	49	159
Collateral received (posted), net	(192)	1,495
Income taxes	423	154
Pension and non-pension postretirement benefit contributions	(193)	(178)
Other assets and liabilities	(346)	(7,977)
Net cash flows provided by (used in) operating activities	3,332	(1,452)
Cash flows from investing activities		
Capital expenditures	(1,963)	(1,836)
Proceeds from NDT fund sales	5,525	4,934
Investment in NDT funds	(5,773)	(5,140)
Collection of DPP, net	—	7,104
Acquisitions of assets and businesses	(13)	(22)
Other investing activities	3	16
Net cash flows provided by (used in) investing activities	(2,221)	5,056
Cash flows from financing activities		
Change in short-term borrowings	—	(1,105)
Proceeds from short-term borrowings with maturities greater than 90 days	1,650	200
Repayments of short-term borrowings with maturities greater than 90 days	—	(739)
Issuance of long-term debt	—	900
Retirement of long-term debt	(1,036)	(99)
Distributions to member	(914)	(1,331)
Contributions from member	156	—
Other financing activities	(45)	—
Net cash flows provided by (used in) financing activities	(189)	(2,174)
Increase (decrease) in cash, restricted cash, and cash equivalents	922	1,430
Cash, restricted cash, and cash equivalents at beginning of period	3,115	440
Cash, restricted cash, and cash equivalents at end of period	$ 4,037	$ 1,870
Supplemental disclosure of non-cash investing and financing activities		
Increase (decrease) in DPP	$ —	$ 7,682
Increase (decrease) in PP&E related to ARO update	188	(1,475)

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2025	December 31, 2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,949	$ 3,018
Restricted cash and cash equivalents	88	97
Accounts receivable, net		
Customer accounts receivable (net of allowance for credit losses of $190 as of September 30, 2025 and December 31, 2024)	3,168	3,116
Other accounts receivable (net of allowance for credit losses of $8 and $6 as of September 30, 2025 and December 31, 2024, respectively)	614	587
Mark-to-market derivative assets	632	843
Inventories, net		
Natural gas, oil, and emission allowances	242	243
Materials and supplies	1,422	1,357
Renewable energy credits	786	797
Other	695	689
Total current assets	11,596	10,747
Property, plant, and equipment (net of accumulated depreciation and amortization of $18,932 and $18,088 as of September 30, 2025 and December 31, 2024, respectively)	21,990	21,235
Deferred debits and other assets		
Nuclear decommissioning trust funds	18,985	17,305
Investments	427	640
Goodwill	420	420
Mark-to-market derivative assets	459	372
Other	2,225	2,174
Total deferred debits and other assets	22,516	20,911
Total assets[a]	$ 56,102	$ 52,893

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	September 30, 2025	December 31, 2024
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 1,650	$ —
Long-term debt due within one year	118	1,028
Accounts payable and accrued expenses	3,668	3,696
Payables to affiliates	298	349
Mark-to-market derivative liabilities	474	467
Renewable energy credit obligation	956	1,076
Other	324	328
Total current liabilities	7,488	6,944
Long-term debt	7,269	7,384
Deferred credits and other liabilities		
Deferred income taxes and unamortized ITCs	3,578	3,331
Asset retirement obligations	13,032	12,449
Pension and non-pension postretirement benefit obligations	1,767	1,875
Spent nuclear fuel obligation	1,412	1,366
Payables related to Regulatory Agreement Units	5,222	4,518
Mark-to-market derivative liabilities	440	399
Other	1,171	1,044
Total deferred credits and other liabilities	26,622	24,982
Total liabilities[(a)]	41,379	39,310
Commitments and contingencies (Note 14)		
Equity		
Member's equity		
Membership interest	10,144	10,538
Undistributed earnings (deficit)	6,497	4,974
Accumulated other comprehensive income (loss), net	(2,260)	(2,302)
Total member's equity	14,381	13,210
Noncontrolling interests	342	373
Total equity	14,723	13,583
Total liabilities and equity	$ 56,102	$ 52,893

(a) Our consolidated assets include $4,358 million and $4,318 million as of September 30, 2025 and December 31, 2024, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Our consolidated liabilities include $925 million and $968 million as of September 30, 2025 and December 31, 2024, respectively, of certain VIEs for which the VIE creditors do not have recourse to us. See Note 16 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30, 2025				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2024	$ 10,538	$ 4,974	$ (2,302)	$ 373	$ 13,583
Net Income (loss)	—	118	—	11	129
Changes in equity of noncontrolling interests	—	—	—	(6)	(6)
Distributions to member	(150)	(122)	—	—	(272)
Other comprehensive income (loss), net of income taxes	—	—	(7)	—	(7)
Balance, March 31, 2025	$ 10,388	$ 4,970	$ (2,309)	$ 378	$ 13,427
Net Income (loss)	—	839	—	(6)	833
Changes in equity of noncontrolling interests	—	—	—	(15)	(15)
Contribution from member	103	—	—	—	103
Distributions to member	(400)	(121)	—	—	(521)
Other comprehensive income (loss), net of income taxes	—	—	37	—	37
Balance, June 30, 2025	$ 10,091	$ 5,688	$ (2,272)	$ 357	$ 13,864
Net Income (loss)	—	930	—	(1)	929
Changes in equity of noncontrolling interests	—	—	—	(14)	(14)
Contribution from member	53	—	—	—	53
Distribution to member	—	(121)	—	—	(121)
Other comprehensive income (loss), net of income taxes	—	—	12	—	12
Balance, September 30, 2025	$ 10,144	$ 6,497	$ (2,260)	$ 342	$ 14,723

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, 2024				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings (Deficit)	Accumulated Other Comprehensive Income (Loss), net	Noncontrolling Interests	Total Equity
Balance, December 31, 2023	$ 11,537	$ 1,667	$ (2,191)	$ 361	$ 11,374
Net Income (loss)	—	883	—	—	883
Distributions to member	(499)	(111)	—	—	(610)
Other comprehensive income (loss), net of income taxes	—	—	11	—	11
Balance, March 31, 2024	$ 11,038	$ 2,439	$ (2,180)	$ 361	$ 11,658
Net Income (loss)	—	814	—	(5)	809
Distributions to member	(500)	(110)	—	—	(610)
Other comprehensive income (loss), net of income taxes	—	—	19	—	19
Balance, June 30, 2024	$ 10,538	$ 3,143	$ (2,161)	$ 356	$ 11,876
Net Income (loss)	—	1,200	—	(4)	1,196
Changes in equity of noncontrolling interests	—	—	—	19	19
Distributions to member	—	(111)	—	—	(111)
Other comprehensive income (loss), net of income taxes	—	—	27	—	27
Balance, September 30, 2024	$ 10,538	$ 4,232	$ (2,134)	$ 371	$ 13,007

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 the nation's largest producer of carbon-free 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, public sector, 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

The accompanying Consolidated Financial Statements as of September 30, 2025 and for the three and nine months ended September 30, 2025 and 2024 are unaudited but, in our opinion, include all adjustments that are considered necessary for a fair statement of the results for the periods reported herein in accordance with GAAP. All adjustments are of a normal, recurring nature, unless otherwise disclosed. The Consolidated Financial Statements include the accounts of our subsidiaries and all intercompany transactions have been eliminated. Constellation's December 31, 2024 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, 2025. 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. Certain prior period amounts have been reclassified to conform to the presentation in the current period. 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.

Summary of Significant Accounting Policies

See Note 1 — Basis of Presentation of our 2024 Form 10-K for additional information on significant accounting policies.

2. Mergers, Acquisitions, and Dispositions

Proposed Acquisition of Calpine Corporation

On January 10, 2025, we entered an agreement and plan of merger (Merger Agreement) with Calpine Corporation (Calpine) under which we will acquire all the outstanding equity interests of Calpine in a cash and stock transaction. Calpine owns and operates a generation fleet of natural gas, geothermal, battery storage, and solar assets with over 27 GWs of generation capacity, in addition to a competitive retail electric supplier platform serving approximately 60 TWhs of load annually. The merger consideration at closing will consist of an aggregate of 50 million newly issued shares of our common stock, no par value, and $4.5 billion in cash. We will also assume approximately $12.7 billion of Calpine’s outstanding debt. We expect to fund the cash portion of the transaction through a combination of cash on hand and cash flow generated by Calpine in the period between signing and closing of the transaction (that will be acquired at closing). Per the terms of the Merger Agreement, consummation of the transaction is to occur by December 31, 2025 (which date may be automatically extended to June 1, 2026, as further provided in the Merger Agreement). See Note 2 — Mergers, Acquisitions, and Dispositions of our 2024 Form 10-K for additional information.

We received regulatory approval for the merger from the PUCT and NYPSC in June 2025 and from the FERC in July 2025. Completion of the transaction is subject to the expiration or termination of any agreement with the DOJ to delay the consummation of the transaction and other customary closing conditions.

Fees incurred as part of the acquisition were not material to the Consolidated Statements of Operations and Comprehensive Income for the nine months ended September 30, 2025.

Acquisition of Joint Ownership in South Texas Project

In November 2023, we completed the acquisition of NRG South Texas LP (renamed and converted as Constellation South Texas, LLC), which owns a 44% undivided ownership interest in the jointly owned STP, a 2,645 MW, dual-unit nuclear plant located in Bay City, Texas. The consideration transferred was $1.66 billion. Other owners include City Public Service Board of San Antonio (CPS, 40%) and the City of Austin, Texas (Austin, 16%). In May 2024, we executed a settlement agreement with all parties (CPS/City of San Antonio, Austin, and NRG Energy, Inc.), resolving all litigation involving our purchase of the ownership interest in STP. The terms of the settlement include us selling a 2% ownership interest in STP to CPS at the same price and terms that we paid NRG Energy, Inc. for our 44% interest. We are working towards closing the transaction which remains subject to regulatory approvals (including the NRC and PUCT), the terms of settlement are not expected to have a material impact on our consolidated financial statements. See Note 2 — Mergers, Acquisitions, and Dispositions of our 2024 Form 10-K for additional information.

3. Regulatory Matters

As discussed in Note 3 — Regulatory Matters of our 2024 Form 10-K, we are involved in various regulatory and legislative proceedings. The following discusses developments in 2025 and updates to the 2024 Form 10-K.

Federal Regulatory Matters

In July 2025, the OBBBA was signed into law, which, among other things, permanently extends key provisions of the 2017 Tax Cuts and Jobs Act, including full bonus depreciation and immediate deduction of research and development expenses. In addition, the OBBBA preserves transferability and certain federal tax credits from the IRA, specifically, 45U for existing nuclear plants through 2032 and 45Y for new nuclear projects, including uprates, restarts, and new reactors, through 2035, while enhancing the credit to allow advanced nuclear facilities to qualify for the energy communities bonus adder, subject to eligibility requirements. As it relates to both 45U and 45Y, certain foreign entity of concern rules must be met to qualify for the respective credits. Overall, the OBBBA reinforces the long-term economic viability of our nuclear generation assets. While the provisions of the OBBBA resulted in acceleration of cash benefits of approximately $200 million, the impact of these provisions recognized in the third quarter of 2025 was not material to our results of operations.

Operating License Renewals

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

In 2019, we and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. FERC subsequently issued a new 50-year license for Conowingo, effective March 1, 2021. Several environmental groups appealed FERC's ruling to the U.S. Court of Appeals for the D.C. Circuit. The court of appeals issued a decision vacating FERC's decision to grant Conowingo its license renewal and sending the matter back to FERC for further proceedings. Upon issuance of the mandate from the U.S. Court of Appeals for the D.C. Circuit, we began operating under an annual license, which renews automatically, containing the same terms as the license that was in effect prior to the 2021 FERC order. MDE informed us that as a result of the U.S. Court of Appeals decision, MDE would be resuming its administrative reconsideration of the 401 Certification.

In September 2025, we reached a settlement agreement with MDE and the other parties to the MDE reconsideration proceeding, Lower Susquehanna Riverkeeper Association, and Waterkeepers Chesapeake, which resolves all outstanding issues relating to the 401 Certification. As a result, MDE issued a Revised Water Quality Certification, which is needed for FERC to move forward with the issuance of a new 50-year license. The Revised Water Quality Certification and accompanying settlement agreement provide for a modified operational flow regime, funding for water quality and resiliency projects, commitments for trash and debris removal, fish and eel passage improvements, funding for freshwater mussel restoration and control of invasive species like

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

snakeheads and blue catfish, and funds to support additional studies on dredging and related activities. Our commitments under the various provisions of this settlement are not effective unless and until FERC approves and issues the new license. The terms of this settlement have no impact on the prior settlement agreement with the DOI.

The financial impact of this settlement and other commitments related to this renewal are estimated to be $15 million to $20 million per year, on average, recognized over the term of the 50-year renewal, inclusive of capital and operating costs. The actual timing and amount of the majority of these costs are not currently fixed and will vary from year to year throughout the life of the new license. We cannot currently predict when FERC will issue the new license. Depreciation provisions continue to assume operation through 2071 given our expectation that a 50-year license will be issued.

Peach Bottom Units 2 and 3. In March 2020, the NRC approved a second 20-year license renewal for Peach Bottom Units 2 and 3. As a result, Peach Bottom Units 2 and 3 were granted the authority to operate through 2053 and 2054, respectively.

Notwithstanding its 2020 approval, in February 2022, the NRC took action to modify Peach Bottom's subsequently renewed licenses in response to a request for hearing that the NRC had not previously adjudicated. In its February 2022 decision, the NRC reversed itself and concluded that the previous environmental review required by the National Environmental Policy Act (NEPA) for the Peach Bottom subsequently renewed licenses was incomplete because it did not adequately address environmental impacts resulting from renewing the units' licenses for an additional 20 years. As a result, the NRC undertook a rulemaking to modify its regulations and guidance to specifically address environmental impacts during the period of subsequent license renewal. In addition, the NRC modified the expiration dates for the Peach Bottom licenses from 2053 and 2054 to 2033 and 2034, respectively, pending the completion of the updated NEPA analysis.

In September 2025, the NRC completed its environmental impact review of Peach Bottom Units 2 and 3, restoring the expiration dates of the respective operating licenses to 2053 and 2054, consistent with current accounting estimates utilized for both depreciation and ARO assumed retirement dates.

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 sustainable solutions.

See Note 4 — Revenue from Contracts with Customers of our 2024 Form 10-K for additional information regarding the performance obligations, revenue recognition, and payment terms associated with these sources of revenue.

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, 2025. 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 mark-to-market derivatives and certain power and gas sales contracts which contain variable volumes and/or variable pricing.

	2025	2026	2027	2028	2029 and thereafter	Total
Remaining performance obligations	$ 56	$ 287	$ 181	$ 116	$ 211	$ 851

Transaction Price Allocated to Previously Satisfied Performance Obligations

Our Clinton and Quad Cities units contract with certain utilities in Illinois which require delivery of all ZECs produced during each planning year (June through May), with total compensation limited by an annual cap for each planning year designed to limit the cost of ZECs to each utility's customers. ZECs delivered that, if paid, would result in the annual cap being exceeded may be paid in subsequent years at the vintage year price as long as the payments would not exceed the annual cap in the year paid. The program commenced June 2017 and continues through May 2027. In various planning years since the program began, we delivered ZECs to the utilities in excess of the annual compensation cap.

The ZEC price and annual compensation cap effective for each planning year are administratively determined by the IPA. For the June 2025 through May 2026 planning year, the ZEC price has been established at $1.17 per ZEC, subject to an annual cap of $224 million. ZECs generated and delivered during this planning year will not exceed the annual cap, and as a result we recognized $201 million of revenue during the second quarter of 2025 as a receivable for ZECs delivered in prior planning years, with payment expected in the third quarter of 2026. As of September 30, 2025, this receivable is included within Customer accounts receivable, net in the Consolidated Balance Sheets.

For the June 2024 through May 2025 planning year, the ZEC price was established at $9.38 per ZEC, subject to an annual cap of $222 million. ZECs generated and delivered during this planning year did not exceed the annual cap, however the revenue recognized during the second quarter of 2024 for ZECs delivered in prior planning years was not material.

Revenue Disaggregation

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

5. Segment Information

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

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

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

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

Constellation's CEO is considered the CODM and evaluates the performance of our electric business activities and allocates resources based on segment RNF, primarily through review of budget-to-actual variance analyses. RNF is Operating revenues net of Purchased power and fuel expenses. 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. In our evaluation of operating segments, we noted the CODM reviews a variety of performance and profitability measures at a consolidated level with a primary focus on RNF reporting at the regional level. Our operating revenues include all sales to third parties as well as government assistance. Purchased power and fuel expenses are considered the significant segment expense. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for our owned generation and fuel costs associated with tolling agreements. The results of our other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include wholesale and retail sales of natural gas, energy-related sales in the United Kingdom, as well as sales of other energy-related products and sustainable solutions that are not significant to our overall results of operations. Further, our unrealized mark-to-market gains and losses on economic hedging activities and our amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. The CODM does not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

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 power sales by geographic region.

The following tables, which relate directly to our Consolidated Statements of Operations and Comprehensive Income, provide the reconciliation of operating revenues, purchased power and fuel expenses, and RNF for our reportable segments for the three and nine months ended September 30, 2025 and 2024.

Three Months Ended September 30, 2025	Revenues from contracts with customers	Other revenues[a]	Total Operating revenues	Total Purchased power and fuel expenses	Total RNF
Mid-Atlantic	$ 1,770	$ (7)	$ 1,763	$ (871)	$ 892
Midwest	1,222	168	1,390	(447)	943
New York	582	(24)	558	(159)	399
ERCOT	375	253	628	(213)	415
Other Power Regions	1,313	230	1,543	(1,200)	343
Total Reportable Segments	5,262	620	5,882	(2,890)	2,992
Other[b][c]	441	247	688	(677)	11
Total Consolidated Results	$ 5,703	$ 867	$ 6,570	$ (3,567)	$ 3,003
Three Months Ended September 30, 2024					
Mid-Atlantic	$ 1,504	$ 99	$ 1,603	$ (794)	$ 809
Midwest	958	317	1,275	(391)	884
New York	472	35	507	(150)	357
ERCOT	307	216	523	(120)	403
Other Power Regions	1,213	230	1,443	(1,010)	433
Total Reportable Segments	4,454	897	5,351	(2,465)	2,886
Other[b][c]	319	880	1,199	(654)	545
Total Consolidated Results	$ 4,773	$ 1,777	$ 6,550	$ (3,119)	$ 3,431

(Dollars in millions, unless otherwise noted)

Nine Months Ended September 30, 2025	Revenues from contracts with customers	Other revenues[a]	Total Operating revenues	Total Purchased power and fuel expenses	Total RNF
Mid-Atlantic	$ 4,811	$ 65	$ 4,876	$ (2,393)	$ 2,483
Midwest	3,958	359	4,317	(1,489)	2,828
New York	1,772	(117)	1,655	(458)	1,197
ERCOT	1,003	486	1,489	(589)	900
Other Power Regions	3,719	558	4,277	(3,560)	717
Total Reportable Segments	15,263	1,351	16,614	(8,489)	8,125
Other[b][d]	1,706	1,139	2,845	(2,594)	251
Total Consolidated Results	$ 16,969	$ 2,490	$ 19,459	$ (11,083)	$ 8,376
Nine Months Ended September 30, 2024					
Mid-Atlantic	$ 4,154	$ (6)	$ 4,148	$ (1,906)	$ 2,242
Midwest	2,951	586	3,537	(1,185)	2,352
New York	1,428	106	1,534	(460)	1,074
ERCOT	819	382	1,201	(375)	826
Other Power Regions	3,673	579	4,252	(3,157)	1,095
Total Reportable Segments	13,025	1,647	14,672	(7,083)	7,589
Other[b][d]	1,413	2,101	3,514	(1,745)	1,769
Total Consolidated Results	$ 14,438	$ 3,748	$ 18,186	$ (8,828)	$ 9,358

(a) Includes revenues from nuclear PTCs as well as derivatives and leases. Intersegment activity in all periods presented is not material.
(b) Represents revenue activities not allocated to a region. See text above for a description of included activities.
(c) Revenues from contracts with customers includes natural gas revenues of $237 million and $184 million and other revenues includes unrealized mark-to-market losses of ($156) million and gains of $516 million for the three months ended September 30, 2025 and 2024, respectively.
(d) Revenues from contracts with customers includes natural gas revenues of $1,252 million and $1,024 million and other revenues includes unrealized mark-to-market losses of ($356) million and gains of $769 million for the nine months ended September 30, 2025 and 2024, respectively.

6. Government Assistance

Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. The nuclear PTC provides a transferable credit up to $15 per MWh (a base credit of $3 per MWh with a five times multiplier provided certain prevailing wage requirements are met) and is subject to phase-out when annual gross receipts are between $25.00 per MWh and $43.75 per MWh and $26.00 per MWh and $44.75 per MWh for 2024 and 2025, respectively. We evaluated and expect to meet the annual prevailing wage requirements at all of our nuclear units and are eligible for the five times multiplier. Both the amount of the PTC and the gross receipts thresholds adjust for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year. The benefits of the PTC may be realized through a credit against our federal income taxes or transferred via sale to an unrelated party. In July 2025, Congress passed the OBBBA which affirmed the provisions of the nuclear PTC with no material changes.

For the three and nine months ended September 30, 2025, our Consolidated Statements of Operations and Comprehensive Income included an estimated nuclear PTC benefit in Operating revenues of approximately $175 million and $220 million, respectively. For the three and nine months ended September 30, 2024, our Consolidated Statements of Operations and Comprehensive Income included an estimated nuclear PTC benefit in Operating revenues of approximately $670 million and $1,380 million, respectively. Our estimates require the exercise of judgment in determining the amount of nuclear PTC expected for each of our nuclear units. The nuclear PTC continues to be the subject of additional guidance, from the U.S. Treasury and IRS, and may materially impact the total amount of the benefits we receive.

(Dollars in millions, unless otherwise noted)

Nuclear PTCs are initially recorded within Other deferred debits and other assets within the Consolidated Balance Sheets and reclassified as a reduction to Accounts payable and accrued expenses when used to reduce our federal income tax payable, or an increase in Cash and cash equivalents or Other current assets when sold, depending on the specific payment terms of each contract.

There were no agreements for sales of nuclear PTCs executed in 2025. During the third quarter of 2024, we executed agreements for the sale of $1 billion of nuclear PTCs to unaffiliated third parties at a nominal discount, with approximately $670 million of cash proceeds received upon sale (included within Cash flows from operating activities in our Consolidated Statements of Cash Flows) and approximately $195 million received in the fourth quarter of 2024. Cash received in 2025 on sale agreements executed in 2024 was approximately $95 million. As of September 30, 2025, our Consolidated Balance Sheets reflect approximately $125 million of nuclear PTCs within Other deferred debits and other assets. As of December 31, 2024, our Consolidated Balance Sheets reflected $185 million of estimated nuclear PTCs within Other deferred debits and other assets, and $95 million within Other current assets. Additionally, as of September 30, 2025 and December 31, 2024, we recognized a reduction to Accounts payable and accrued expenses in our Consolidated Balance Sheets of $270 million and $150 million, respectively, for estimated nuclear PTCs that we have utilized as a credit against our current federal income taxes payable.

Many of the state-sponsored programs providing compensation for the emissions-free attributes of generation from certain of our nuclear units include contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received. As of September 30, 2025 and December 31, 2024, we have recognized approximately $1,140 million and $1,030 million, respectively, of estimated payables within Other deferred credits and other liabilities, Accounts payable and accrued expenses or as offsets to Customer accounts receivable in our Consolidated Balance Sheets associated with programs requiring refunds or pass through of the nuclear PTC. During the three and nine months ended September 30, 2025, we recognized a reduction to net operating revenue of approximately $220 million and $30 million, respectively, associated with these programs in our Consolidated Statements of Operations and Comprehensive Income, compared to a reduction to net operating revenue of approximately $115 million and increase to net operating revenue (pre-tax) of approximately $10 million during the three and nine months ended September 30, 2024, respectively. As with the actual amount of the nuclear PTC earned, which cannot be determined until after the end of the calendar year, any change resulting from additional guidance received may materially impact amounts due under state-sponsored programs.

7. Accounts Receivable

Allowance for Credit Losses on Accounts Receivable

The following table presents the rollforward of allowance for credit losses on Customer accounts receivable. The activity and balances were not material for the nine months ended September 30, 2024 given it did not include an allowance related to the sales of customer accounts receivable disclosed below.

Balance as of December 31, 2024	$ 190
Current period provision for expected credit losses	35
Write-offs, net of recoveries[a]	(35)
Balance as of September 30, 2025	$ 190

(a) Recoveries were not material.

The Allowance for credit losses on Other accounts receivable was not material as of the balance sheet dates.

Unbilled Customer Revenue

We recorded $1,045 million and $1,109 million of unbilled customer revenues in Customer accounts receivables, net in the Consolidated Balance Sheets as of September 30, 2025 and December 31, 2024, respectively.

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

Sales of Customer Accounts Receivable

In 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 (Purchasers) to sell certain customer accounts receivable (Facility). On December 31, 2024, we amended the Facility. We no longer sell receivables to the Purchasers and all outstanding receivables were assigned back to us. Under the Facility's prior terms, NER sold eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers were reported as sales of receivables in the consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP. As a result of the receivables being assigned back to NER under the amended Facility, NER forgave any and all remaining DPP owed by the Purchasers. The reassignment of receivables resulted in the recognition of $1,529 million of Customer accounts receivable as of December 31, 2024. See Note 12 — Debt and Credit Agreements for terms of the amended Facility.

The following table presents our cash proceeds associated with the Facility prior to the amendment.

	Nine Months Ended September 30, 2024
Proceeds from new transfers[(a)]	$ 1,688
Cash collections received on DPP[(b)]	7,404
Cash collections reinvested in the Facility	$ 9,092

(a) Customer accounts receivable sold into the Facility was $9,370 million.
(b) Does not include the $300 million net cash payments made to the Purchasers in order to reduce the outstanding borrowing amount under the Facility.

We previously recognized the cash proceeds received upon sale in Cash flows from operating activities within the Changes in Other assets and liabilities line in the Consolidated Statements of Cash Flows, which was ($7,682) million for the nine months ended September 30, 2024. The collection and reinvestment of DPP was recognized in Cash flows from investing activities in the Collection of DPP, net line in the Consolidated Statements of Cash Flows, which was $7,104 million for the nine months ended September 30, 2024.

See Note 16 — Variable Interest Entities for additional information on NER.

Other Sales of Customer Accounts Receivables

We are required, under supplier tariffs, to sell customer receivables to certain utility companies at a nominal discount. The total gross receivables sold were $3,207 million and $228 million for the nine months ended September 30, 2025 and 2024, respectively. Prior to the Facility amendment discussed in the preceding paragraphs, certain accounts receivable subject to these supplier tariffs were sold to the Purchasers under the Facility.

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. See Note 10 — Asset Retirement Obligations of our 2024 Form 10-K for additional information regarding AROs and the financial statement impact of changes in estimates.

The following table provides a rollforward of the nuclear decommissioning AROs reflected in the Consolidated Balance Sheets from December 31, 2024 to September 30, 2025:

Balance as of December 31, 2024	$ 12,186
Accretion expense	467
Net increase due to changes in, and timing of, estimated future cash flows	108
Costs incurred related to decommissioning plants	(12)
Balance as of September 30, 2025	$ 12,749

(Dollars in millions, unless otherwise noted)

During the nine months ended September 30, 2025, the net $108 million increase in the ARO for the changes in, and timing of, estimated future cash flows was driven primarily by higher escalation rates partially offset by higher discount rates and revised cost studies for Braidwood, Byron, Clinton, and LaSalle plants.

NDT Funds

We had NDT funds totaling $19,040 million and $17,321 million as of September 30, 2025 and December 31, 2024, respectively. The current portions of the NDT funds, which are included in Other current assets in our Consolidated Balance Sheets, were not material as of September 30, 2025 and December 31, 2024. See Note 17 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreement Units

See Note 1 — Basis of Presentation and Note 10 — Asset Retirement Obligations of our 2024 Form 10-K for additional information on the Regulatory Agreement Units.

The following table presents our noncurrent payables to ComEd, PECO, CenterPoint, and AEP Texas reflected as Payables related to Regulatory Agreement Units in the Consolidated Balance Sheets as of September 30, 2025 and December 31, 2024:

	September 30, 2025	December 31, 2024
ComEd	$ 4,231	$ 3,780
PECO	427	247
CenterPoint	418	365
AEP Texas	146	126
Payables related to Regulatory Agreement Units	$ 5,222	$ 4,518

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 for radiological decommissioning of the facility at the end of its life.

We filed our biennial decommissioning funding status report with the NRC in March 2025 for all units, including our shutdown units, except for STP units which were included in a separate report to the NRC submitted by STPNOC. The status reports demonstrated adequate decommissioning funding assurance based on trust fund values as of December 31, 2024 for all our units except for Peach Bottom Unit 1. Financial assurance for decommissioning Peach Bottom Unit 1 is provided by collections from PECO customers. See Note 10 — Asset Retirement Obligations of our 2024 Form 10-K for additional information.

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

9. Income Taxes

Rate Reconciliation

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

	Three Months Ended September 30,			
	2025		2024	
U.S. federal statutory income tax	21.0 %	$ 293	21.0 %	$ 345
(Decrease) increase due to:				
State income taxes, net of federal income tax benefit[a]	5.1	71	4.8	80
Foreign tax effects	0.1	1	0.1	1
Tax credits				
PTC	(2.8)	(40)	(8.0)	(132)
Amortization of ITC, including deferred taxes on basis differences	(0.3)	(4)	(0.3)	(5)
Other	(0.2)	(3)	(0.1)	(1)
Nontaxable or nondeductible items				
Share-based payment awards	—	—	(0.1)	(1)
Excess officers compensation	1.0	14	1.3	21
Other	0.9	12	0.4	6
Other adjustments				
Qualified NDT fund income and losses	8.6	122	8.2	135
Effective income tax[b]	33.4 %	$ 466	27.3 %	$ 449

	Nine Months Ended September 30, 2025			
	2025		2024	
U.S. federal statutory income tax	21.0 %	$ 592	21.0 %	$ 768
(Decrease) increase due to:				
State income taxes, net of federal income tax benefit[a]	4.2	118	1.1	39
Foreign tax effects	0.1	2	0.1	2
Tax credits				
PTC	(1.9)	(53)	(7.7)	(281)
Amortization of ITC, including deferred taxes on basis differences	(0.4)	(10)	(0.3)	(10)
Other	(0.3)	(8)	(0.4)	(14)
Nontaxable or nondeductible items				
Share-based payment awards	(1.4)	(40)	(0.4)	(16)
Excess officers compensation	1.1	30	0.8	30
Other	0.4	13	0.2	9
Other adjustments				
Qualified NDT fund income and losses	10.1	284	6.6	241
Effective income tax[b]	32.9 %	$ 928	21.0 %	$ 768

(a) State taxes in California, Illinois, Maryland, Massachusetts, and New Jersey made up the majority (greater than 50%) of the tax effect in this category.
(b) Amounts may not recalculate due to rounding.

Other Tax Matters

One Big Beautiful Bill Act

In July 2025, Congress passed the OBBBA which, among other things, included certain changes in tax law. See Note 3 — Regulatory Matters for additional information.

Tax Matters Agreement

In connection with the separation, we entered 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 in which we were included in joint federal and state filings. However, the TMA specifies the portion of this tax liability for which we will bear contractual responsibility, and we and Exelon 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 of September 30, 2025 and December 31, 2024, respectively, our Consolidated Balance Sheets reflect $42 million and $39 million in Other deferred credits and other liabilities, for tax liabilities where we maintain contractual responsibility to Exelon.

Tax Refunds and Attributes. The TMA provides for the allocation of certain pre-closing tax attributes between us and Exelon. Tax attributes will be allocated in accordance with the principles set forth in the existing Exelon tax sharing agreement, unless otherwise required by law. Under the TMA, we will be entitled to refunds for taxes for which we are responsible. In addition, it is expected that Exelon will have tax attributes that may be used to offset Exelon’s future tax liabilities. A significant portion of such attributes were generated by our business. In February 2024, we executed an amendment to the TMA that modified the timing of Exelon's payment of amounts due to us. During the second quarter of 2025 and 2024, we received payments for tax attributes utilized by Exelon related to the 2024 and 2023 tax years of $127 million and $183 million, respectively. As of September 30, 2025 and December 31, 2024, respectively, we had $174 million and $138 million in Other accounts receivable and $38 million and $201 million in Other deferred debits and other assets for the reclassified tax attributes expected to be utilized by Exelon after separation in accordance with the terms of the TMA.

(Dollars in millions, unless otherwise noted)

10. Retirement Benefits

Components of Net Periodic Benefit (Credits) Costs

See Note 1 — Basis of Presentation of our 2024 Form 10-K for additional information on where we report the service cost and other non-service cost (credit) components for all plans.

The following tables present the components of our net periodic benefit (credit) cost for the three and nine months ended September 30, 2025 and 2024. The amounts below are shown prior to capitalization and co-owner allocations, the effects of which were not material for any of the periods presented.

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
Three Months Ended September 30,	2025	2024	2025	2024	2025	2024
Components of net periodic benefit (credit) cost:						
Service cost	$ 21	$ 22	$ 4	$ 4	$ 25	$ 26
Non-service components of pension benefits & OPEB (credit) cost:						
Interest cost	101	95	19	18	120	113
Expected return on assets	(122)	(123)	(9)	(11)	(131)	(134)
Amortization of:						
Prior service (credit) cost	1	1	(2)	(2)	(1)	(1)
Actuarial (gain) loss	26	25	(2)	(3)	24	22
Settlement charges	1	3	—	—	1	3
Non-service components of pension benefits & OPEB (credit) cost	7	1	6	2	13	3
Net periodic benefit (credit) cost	$ 28	$ 23	$ 10	$ 6	$ 38	$ 29

	Pension Benefits		OPEB		Total Pension Benefits and OPEB	
Nine Months Ended September 30,	2025	2024	2025	2024	2025	2024
Components of net periodic benefit (credit) cost:						
Service cost	$ 63	$ 67	$ 13	$ 13	$ 76	$ 80
Non-service components of pension benefits & OPEB (credit) cost:						
Interest cost	306	286	58	54	364	340
Expected return on assets	(367)	(371)	(25)	(32)	(392)	(403)
Amortization of:						
Prior service (credit) cost	1	1	(5)	(5)	(4)	(4)
Actuarial (gain) loss	77	76	(6)	(7)	71	69
Settlement charges	1	7	—	—	1	7
Non-service components of pension benefits & OPEB (credit) cost	18	(1)	22	10	40	9
Net periodic benefit (credit) cost	$ 81	$ 66	$ 35	$ 23	$ 116	$ 89

11. 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, including NPNS, are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. All derivative instruments, excluding NPNS, 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 delivered.

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, our energy-related economic hedges 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 were downgraded below investment grade. As our senior unsecured debt rating is currently rated at BBB+ and Baa1 by S&P and Moody's, respectively, it would take a three-notch downgrade by S&P or Moody's for our rating to go 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 energy-related products. We believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

To the extent the amount of energy we produce or procure differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in the prices of electricity, natural gas, and 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.

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. Beginning in 2024, our existing nuclear fleet is eligible for a nuclear PTC, an important tool in managing commodity price risk for each nuclear unit not already receiving state support. The nuclear PTC provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year. See Note 6 — Government Assistance for additional information.

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

In locations and periods where our load serving activities do not naturally offset existing generation portfolio risk, remaining commodity price exposure is managed through portfolio hedging activities. Portfolio hedging activities are generally concentrated in the prompt three years, when customer demand and market liquidity enable effective price risk mitigation. During this prompt three-year period, we seek to mitigate the price risk associated with our load serving contracts, non-nuclear generation, and any residual price risk for our nuclear generation that the nuclear PTC and state programs may not fully mitigate. We also enter transactions that further optimize the economic benefits of our overall portfolio.

The following tables provide a summary of the commodity derivative fair value balances recorded as of September 30, 2025 and December 31, 2024:

September 30, 2025	Economic Hedges	Collateral[(a)]	Netting[(a)]	Total
Mark-to-market derivative assets (current)	$ 6,245	$ 218	$ (5,836)	$ 627
Mark-to-market derivative assets (noncurrent)	4,444	166	(4,152)	458
Total mark-to-market derivative assets	10,689	384	(9,988)	1,085
Mark-to-market derivative liabilities (current)	(6,495)	195	5,836	(464)
Mark-to-market derivative liabilities (noncurrent)	(4,788)	197	4,152	(439)
Total mark-to-market derivative liabilities	(11,283)	392	9,988	(903)
Total mark-to-market derivative net assets (liabilities)	$ (594)	$ 776	$ —	$ 182

December 31, 2024	Economic Hedges	Collateral[(a)]	Netting[(a)]	Total
Mark-to-market derivative assets (current)	$ 5,518	$ 152	$ (4,860)	$ 810
Mark-to-market derivative assets (noncurrent)	3,672	120	(3,421)	371
Total mark-to-market derivative assets	9,190	272	(8,281)	1,181
Mark-to-market derivative liabilities (current)	(5,498)	173	4,860	(465)
Mark-to-market derivative liabilities (noncurrent)	(3,961)	141	3,421	(399)
Total mark-to-market derivative liabilities	(9,459)	314	8,281	(864)
Total mark-to-market derivative net assets (liabilities)	$ (269)	$ 586	$ —	$ 317

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

The following table summarizes the net buy/(sell) notional position of commodity derivative transactions, excluding our NPNS derivatives that are not recorded at fair value, as of September 30, 2025 and December 31, 2024:

	Total Net Position (In Millions)		
Commodity Type	September 30, 2025	December 31, 2024	Unit of Measure
Electricity	(261)	(130)	MWh
Natural Gas	(130)	33	MMBtu
Emissions	(32)	(18)	Short Ton

(Dollars in millions, unless otherwise noted)

Economic Hedges (Commodity Price Risk)

For the three and nine months ended September 30, 2025 and 2024, we recognized the following net pre-tax commodity mark-to-market gains (losses), which are also included 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,	
Income Statement Location	**2025**	**2024**	**2025**	**2024**
Operating revenues	$ (158)	$ 519	$ (354)	$ 774
Purchased power and fuel	28	(119)	67	404
Total	$ (130)	$ 400	$ (287)	$ 1,178

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 $1,506 million and $592 million as of September 30, 2025 and December 31, 2024, respectively.

The mark-to-market derivative assets and liabilities as of September 30, 2025 and December 31, 2024 and 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, 2025 and 2024 were not material. The mark-to-market gains and losses associated with management of interest rate and foreign currency exchange rate risk are also included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

Credit Risk

We would be exposed to credit-related losses in the event of non-performance by counterparties on executed derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts as of the reporting date.

For commodity derivatives, we enter into enabling agreements that allow for payment netting with our counterparties, which reduces our exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allows for cross product netting. In addition to right of offset 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 other risk management criteria. 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.

(Dollars in millions, unless otherwise noted)

The following tables provide information on the credit exposure for derivative instruments, NPNS and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2025. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, forward values on non-derivative contracts and exposure through RTOs, ISOs, as well as commodity exchanges. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties.

Rating as of September 30, 2025	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	$ 775	$ 13	$ 762	1	$ 151
Non-investment grade	7	—	7	—	—
No external ratings					
Internally rated — investment grade	134	6	128	—	—
Internally rated — non-investment grade	152	36	116	—	—
Total	$ 1,068	$ 55	$ 1,013	1	$ 151

(a) As of September 30, 2025, credit collateral held from counterparties where we had credit exposure included $1 million of cash and $54 million of letters of credit.

Net Credit Exposure by Type of Counterparty	As of September 30, 2025
Investor-owned utilities, marketers, power producers	$ 834
Energy cooperatives and municipalities	85
Financial Institutions	46
Other	48
Total	$ 1,013

Credit-Risk-Related Contingent Features

As part of the normal course of business, we routinely enter into physically and financially settled contracts for the purchase and sale of 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 ratings from S&P and Moody's. 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 ratings (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 such cases, we believe an amount of several months of future payments (e.g., capacity payments) rather than a calculation of fair value is a reasonable estimate for the contingent collateral obligation, which has been factored into the disclosure below.

(Dollars in millions, unless otherwise noted)

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, 2025	December 31, 2024
Gross fair value of derivative contracts containing this feature	$ (1,374)	$ (1,346)
Offsetting fair value of derivative contracts under master netting arrangements	575	602
Net fair value of derivative contracts containing this feature	$ (799)	$ (744)

As of September 30, 2025 and December 31, 2024, 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, 2025	December 31, 2024
Cash collateral posted[(a)]	$ 828	$ 635
Letters of credit posted[(a)]	900	890
Cash collateral held[(a)]	52	49
Letters of credit held[(a)]	130	91
Additional collateral required in the event of a credit downgrade below investment grade (at BB+/Ba1)[(b)(c)(d)]	2,440	1,949

(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 and excludes any contracts with individual retail counterparties.
(d) A loss of investment grade credit rating would require a three-notch downgrade from current levels of BBB+ and Baa1 at S&P and Moody's, respectively.

We routinely enter 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, we are required to post collateral once certain unsecured credit limits are exceeded.

12. 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.

Credit Agreements

In September 2025, we amended our existing revolving credit facility (RCF) to increase the available aggregate commitment from $4.5 billion to $7.0 billion, which included incremental revolving credit commitments of $2.5 billion and extension of the maturity date to September 2030. The incremental commitments will be available upon the closing of the Calpine acquisition. See Note 2 — Mergers, Acquisitions, and Dispositions for additional information. The RCF may be drawn down in the form of loans and/or to support commercial paper and letter of credit issuances.

The RCF fixed facility fee rate is 0.175% and borrowings under the RCF bear interest at a rate based upon either the Daily Simple SOFR rate or a Term SOFR rate, plus an adder based upon our credit rating. The adders for the

(Dollars in millions, unless otherwise noted)

Daily Simple SOFR-based borrowings and Term SOFR borrowings are 0.075% and 1.075%, respectively. The letters of credit bear interest at a rate of 1.075%.

If we were to lose our investment grade credit rating, the maximum adders for Daily Simple SOFR rate borrowings and Term SOFR rate borrowings would be 1.00% and 2.00%, respectively. The credit agreements also require us to pay facility fees based upon the aggregate commitments. The fees vary depending upon our credit rating.

Accounts Receivable Facility

In December 2024, we amended the Facility to provide NER access to revolving loans from a number of financial institutions (Lenders) secured by certain customer accounts receivable. As part of the amendment, the maximum funding limit of the Facility was increased from $1.1 billion to $1.5 billion and the maturity date was extended to December 2027. Under previous terms of the Facility, certain customer accounts receivable were sold to the Purchasers. Immediately following the amendment, all receivables previously sold were assigned back to us and receivables will no longer be sold to the Purchasers under the amendment. Subsequent to the amendment, draws and repayments related to the Facility will be reflected as Proceeds from short-term borrowings and Repayments of short-term borrowings, respectively, in the Consolidated Statements of Cash Flows. Draws on the facility bear interest at a commercial paper rate or a Daily One Month Term SOFR or Term SOFR rate, plus an adder of 0.10% per annum. Interest is payable monthly. There were no draws on the Facility as of September 30, 2025.

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

As of September 30, 2025 and December 31, 2024, we had the following aggregate bank commitments, credit facility borrowings and available capacity under our respective credit facilities:

Facility Type	Aggregate Bank Commitment	Facility Draws	Outstanding Letters of Credit[a]	Outstanding Commercial Paper[b]	Total Available Capacity
September 30, 2025					
Revolving Credit Facility	$ 4,500	$ —	$ 49	$ —	$ 4,451
Bilaterals[c]	2,350	—	1,167	—	1,183
Accounts Receivable Facility	1,500	—	—	—	1,500
Liquidity Facility	971	—	789	—	159 [c]
Project Finance	137	—	122	—	15
Total	$ 9,458	$ —	$ 2,127	$ —	$ 7,308
December 31, 2024					
Revolving Credit Facility	$ 4,500	$ —	$ 51	$ —	$ 4,449
Bilaterals	1,850	—	1,095	—	755
Accounts Receivable Facility	1,500	—	—	—	1,500
Liquidity Facility	971	—	907	—	21 [c]
Project Finance	137	—	120	—	17
Total	$ 8,958	$ —	$ 2,173	$ —	$ 6,742

(a) Excludes an additional outstanding letter of credit which was not issued under these facilities of $15 million as of September 30, 2025 and December 31, 2024. See Note 14 — Commitments and Contingencies for additional information.
(b) Our commercial paper program is supported by the revolving credit agreement. In order to maintain our commercial paper program in the amounts indicated above, we must have a credit facility in place, at least equal to the amount of our commercial paper program. As of September 30, 2025 and December 31, 2024, the maximum program size of our commercial paper program was $4.5 billion. We do not issue commercial paper in an aggregate amount exceeding the then available capacity under our credit facility. There were no commercial paper borrowings outstanding as of September 30, 2025 and December 31, 2024.

(Dollars in millions, unless otherwise noted)

(c) In January 2025, we initiated a new bilateral credit agreement for $200 million, with no maturity date. In March 2025, a bilateral credit agreement initiated in March 2023 was extended for an additional two years to March 2027. In March 2025, we initiated a new bilateral credit agreement for $300 million, scheduled to mature March 2026.

(d) 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, 2025 and December 31, 2024, without posting additional collateral, the actual availability of facility, prior to outstanding letters of credit was $948 million and $928 million, respectively.

Short-Term Loan Agreements

As of September 30, 2025 we had the following short-term loan agreements, both of which are unsecured and reflected in Short-term borrowings in the Consolidated Balance Sheets:

Month Initiated	Interest Rate	Maturity	Outstanding Amount as of September 30, 2025	Outstanding Amount as of December 31, 2024
May 2025	1-month SOFR + 0.90%	May 2026	$ 900	$ —
September 2025	1-month SOFR + 0.90%	September 2026	750	—

Long-Term Debt

Debt Issuances and Redemptions

During the nine months ended September 30, 2025, the following long-term debt was issued (redeemed):

Type	Interest Rate	Maturity	Amount
2025 Senior Notes	3.25%	June 2025	$ (900)
CR Nonrecourse Debt	3-month SOFR + 2.25%	December 2027	(34)
Continental Wind Nonrecourse Debt	6.00%	February 2033	(31)
West Medway II Nonrecourse Debt	1-month SOFR + 3.225% - 3.350%	March 2026	(26)
Tax Exempt Pollution Control Revenue Bonds	4.45%	March 2025	(23)
Antelope Valley DOE Nonrecourse Debt	2.29% - 3.56%	January 2037	(15)
RPG Nonrecourse Debt	4.11%	March 2035	(7)
Total long-term debt issued (redeemed)			$ (1,036)

Debt Covenants

As of September 30, 2025, we are in compliance with all debt covenants.

(Dollars in millions, unless otherwise noted)

13. Fair Value of Financial Assets and Liabilities

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

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

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following table presents the carrying amounts and fair values of our long-term debt and SNF obligation as of September 30, 2025 and December 31, 2024. 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, 2025				December 31, 2024			
	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	$ 7,387	$ 7,060	$ 681	$ 7,741	$ 8,412	$ 7,805	$ 716	$ 8,521
SNF Obligation	1,412	1,407	—	1,407	1,366	1,278	—	1,278

Valuation Techniques Used to Determine Fair Value and Net Asset Value

Our valuation techniques used to measure the fair value and net asset value of the assets and liabilities are in accordance with the policies discussed in Note 17 — Fair Value of Financial Assets and Liabilities of our 2024 Form 10-K.

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

Recurring Fair Value Measurements

The following table presents 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, 2025 and December 31, 2024:

	September 30, 2025				December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$ 30	$ —	$ —	$ 30	$ 120	$ —	$ —	$ 120
NDT fund investments								
Cash equivalents[b]	368	172	—	540	187	163	—	350
Equities	6,291	1,537	—	7,828	5,230	1,897	—	7,127
Fixed income	2,209	1,564	387	4,160	2,089	1,462	368	3,919
Private credit	—	—	130	130	—	—	134	134
Assets measured at NAV	—	—	—	6,382	—	—	—	5,791
NDT fund investments subtotal[c]	8,868	3,273	517	19,040	7,506	3,522	502	17,321
Rabbi trust investments	63	43	1	107	58	41	1	100
Investments in equities	112	—	—	112	389	—	—	389
Mark-to-market derivative assets								
Economic hedges	1,264	4,893	4,538	10,695	1,278	5,306	2,641	9,225
Effect of netting and allocation of collateral	(1,118)	(4,645)	(3,841)	(9,604)	(1,097)	(4,790)	(2,123)	(8,010)
Mark-to-market derivative assets subtotal	146	248	697	1,091	181	516	518	1,215
Total assets measured at fair value	9,219	3,564	1,215	20,380	8,254	4,079	1,021	19,145
Liabilities								
Mark-to-market derivative liabilities								
Economic hedges	(1,270)	(5,090)	(4,934)	(11,294)	(1,222)	(5,462)	(2,778)	(9,462)
Effect of netting and allocation of collateral	1,207	4,991	4,182	10,380	1,180	5,157	2,259	8,596
Mark-to-market derivative liabilities subtotal	(63)	(99)	(752)	(914)	(42)	(305)	(519)	(866)
Deferred compensation obligation	—	(116)	—	(116)	—	(93)	—	(93)
Total liabilities measured at fair value	(63)	(215)	(752)	(1,030)	(42)	(398)	(519)	(959)
Total net assets	$ 9,156	$ 3,349	$ 463	$ 19,350	$ 8,212	$ 3,681	$ 502	$ 18,186

(a) CEG Parent has $75 million and $130 million of Level 1 cash equivalents as of September 30, 2025 and December 31, 2024, respectively. We exclude cash of $3,928 million and $2,924 million, and restricted cash of $79 million and $71 million as of September 30, 2025 and December 31, 2024, respectively. CEG Parent has excluded an additional $9 million and $4 million of cash as of September 30, 2025 and December 31, 2024, respectively.
(b) Includes net liabilities of $149 million and $148 million as of September 30, 2025 and December 31, 2024, respectively, which 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.
(c) Includes total NDT derivative assets and liabilities that are not material, which have notional amounts of $1,173 million and $1,119 million as of September 30, 2025 and December 31, 2024, respectively. The notional principal amounts 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.

As of September 30, 2025, our NDTs have outstanding commitments to invest in private credit, private equity, and real assets of $479 million, $451 million, and $673 million, respectively. These commitments will be funded by our existing NDT funds.

(Dollars in millions, unless otherwise noted)

Equity Security Investments without Readily Determinable Fair Values. We hold investments without readily determinable fair values with carrying amounts of $206 million and $150 million as of September 30, 2025 and December 31, 2024, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and nine months ended September 30, 2025 and the year ended December 31, 2024.

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, 2025 and 2024:

	Three Months Ended September 30, 2025			
	NDT Fund Investments	Mark-to-Market Derivatives	Rabbi Trust Investments	Total
Balance as of July 1, 2025	$ 504	$ 137	$ 1	$ 642
Total realized / unrealized gains (losses)				
Included in net income (loss)	4	(211) [a]	—	(207)
Included in Payables related to Regulatory Agreement Units	9	—	—	9
Change in collateral	—	58	—	58
Purchases	—	17	—	17
Transfers into Level 3	—	(1) [b]	—	(1)
Transfers out of Level 3	—	(55) [b]	—	(55)
Balance as of September 30, 2025	$ 517	$ (55)	$ 1	$ 463
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, 2025	$ 4	$ (114)	$ —	$ (110)

	Three Months Ended September 30, 2024			
	NDT Fund Investments	Mark-to-Market Derivatives	Rabbi Trust Investments	Total
Balance as of July 1, 2024	$ 492	$ 312	$ 1	$ 805
Total realized / unrealized gains (losses)				
Included in net income (loss)	4	58 [a]	—	62
Included in Payables related to Regulatory Agreement Units	9	—	—	9
Change in collateral	—	(166)	—	(166)
Purchases	—	14	—	14
Settlements	(7)	—	—	(7)
Transfers into Level 3	1	(12) [b]	—	(11)
Transfers out of Level 3	—	— [b]	—	—
Balance as of September 30, 2024	$ 499	$ 206	$ 1	$ 706
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, 2024	$ 4	$ 191	$ —	$ 195

(Dollars in millions, unless otherwise noted)

	Nine Months Ended September 30, 2025			
	NDT Fund Investments	Mark-to-Market Derivatives	Rabbi Trust Investments	Total
Balance as of January 1, 2025	$ 502	$ (1)	$ 1	$ 502
Total realized / unrealized gains (losses)				
Included in net income (loss)	6	(248) [(a)]	—	(242)
Included in Payables related to Regulatory Agreement Units	12	—	—	12
Change in collateral	—	205	—	205
Purchases	—	68	—	68
Sales	—	(5)	—	(5)
Settlements	(4)	—	—	(4)
Transfers into Level 3	1	(44) [(b)]	—	(43)
Transfers out of Level 3	—	(30) [(b)]	—	(30)
Balance as of September 30, 2025	$ 517	$ (55)	$ 1	$ 463
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, 2025	$ 6	$ (4)	$ —	$ 2

	Nine Months Ended September 30, 2024			
	NDT Fund Investments	Mark-to-Market Derivatives	Rabbi Trust Investments	Total
Balance as of January 1, 2024	$ 429	$ 869	$ 1	$ 1,299
Total realized / unrealized gains (losses)				
Included in net income (loss)	4	(433) [(a)]	—	(429)
Included in Payables related to Regulatory Agreement Units	13	—	—	13
Change in collateral	—	(173)	—	(173)
Purchases	66	32	—	98
Sales	—	(83)	—	(83)
Settlements	(14)	(2)	—	(16)
Transfers into Level 3	1	27 [(b)]	—	28
Transfers out of Level 3	—	(31) [(b)]	—	(31)
Balance as of September 30, 2024	$ 499	$ 206	$ 1	$ 706
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, 2024	$ 4	$ 216	$ —	$ 220

(a) Includes a reduction of ($97) million and ($244) million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2025, respectively. Includes a reduction of ($133) million and ($651) million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2024, 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.

(Dollars in millions, unless otherwise noted)

The following table presents the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2025 and 2024:

	Three Months Ended September 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2025	2024	2025	2024	2025	2024
Total gains (losses) included in net income	$ (272)	$ 177	$ 61	$ (119)	$ 4	$ 4
Total unrealized gains (losses)	(186)	300	72	(109)	4	—

	Nine Months Ended September 30,					
	Operating Revenues		Purchased Power and Fuel		Other, net	
	2025	2024	2025	2024	2025	2024
Total gains (losses) included in net income	$ (271)	$ (97)	$ 23	$ (338)	$ 6	$ 4
Total unrealized gains (losses)	(120)	561	116	(345)	6	—

Mark-to-Market Derivatives

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

Type of trade	Fair Value as of September 30, 2025	Fair Value as of December 31, 2024	Valuation Technique	Unobservable Input	2025 Range & Arithmetic Average		2024 Range & Arithmetic Average	
Mark-to-market derivatives—Economic hedges[(a)(b)]	$ (396)	$ (137)	Discounted Cash Flow	Forward power price	$5.83 - $154	$52	$2.57 - $140	$49
				Forward gas price	$(0.22) - $14	$3.83	$2.09 - $15	$3.68
			Option Model	Volatility percentage	6% - 174%	61%	23% - 141%	57%

(a) The valuation techniques, unobservable inputs, ranges, and arithmetic averages are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted (received) on Level 3 positions of $341 million and $136 million as of September 30, 2025 and December 31, 2024, 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 heat rate 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.

(Dollars in millions, unless otherwise noted)

14. Commitments and Contingencies

Commitments

Commercial Commitments. Commercial commitments as of September 30, 2025, representing commitments potentially triggered by future events, were as follows:

	Expiration within						
	2025	2026	2027	2028	2029	2030 and beyond	Total
Letters of credit	$ 1,320	$ 696	$ 2	$ 123	$ —	$ 1	$ 2,142
Surety bonds[a]	219	462	—	214	—	—	895
Total commercial commitments	$ 1,539	$ 1,158	$ 2	$ 337	$ —	$ 1	$ 3,037

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

Environmental Remediation Matters

General. Our operations have in the past, and may in the future, require substantial expenditures to comply with environmental laws. Additionally, under Federal and state environmental laws, we are generally liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated by us. We own or lease several real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, we are currently involved in proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, we cannot reasonably estimate whether we will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by us, environmental agencies, or others. Additional costs could have a material, unfavorable impact on our consolidated financial statements.

As of September 30, 2025 and December 31, 2024, we had accrued undiscounted amounts for environmental liabilities of $10 million and $60 million, respectively, in Accounts payable and accrued expenses and $163 million and $169 million, respectively, in Other deferred credits and other liabilities in the Consolidated Balance Sheets. See Note 18 — Commitments and Contingencies of our 2024 Form 10-K for additional information on environmental remediation matters. As of September 30, 2025, and through the date of filing, there have been no material changes in amounts recognized for the matters discussed in our 2024 Form 10-K.

Litigation

We are involved in various 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.

See Note 18 — Commitments and Contingencies of our 2024 Form 10-K for additional information on litigation matters. As of September 30, 2025, and through the date of filing, there have been no material changes in amounts recognized for the matters discussed in our 2024 Form 10-K.

15. Shareholders' Equity

Share Repurchase Program (CEG Parent)

Since 2023, our Board of Directors authorized the repurchase of up to $3 billion of the Company's outstanding common stock. As of September 30, 2025, there was approximately $593 million of remaining authority to repurchase shares of the Company's outstanding common stock, which reflects the net impact of capped call options, as discussed below. No other repurchase plans or programs have been authorized. See Note 19 — Shareholders' Equity of our 2024 Form 10-K for additional information on our share repurchase program.

During the three and nine months ended September 30, 2025, there were no open market repurchases. During the nine months ended September 30, 2024, we repurchased from the open market 1.2 million shares of our common stock for a total cost, inclusive of taxes and transaction costs, of $150 million. There were no open market repurchases during the three months ended September 30, 2024.

In 2024 and 2025, we entered into ASR agreements with financial institutions to initiate share repurchases of our common stock. Under the ASR agreements, we paid a specified amount to the financial institutions and received an initial delivery of shares of common stock, which resulted in an immediate reduction in the number of our shares outstanding. Based on the terms of the ASR agreements, we received an initial share delivery based on 80% of each ASR agreements' cost. Upon settlement of the ASR agreements, the financial institution delivers additional incremental shares. The total number of shares ultimately delivered, and therefore the average price paid per share, is determined at the end of the applicable purchase period of each ASR agreement based on the average of the daily-volume weighted average share price, less a discount.

The following table summarizes the activity of our ASR agreements for the nine months ended September 30, 2025 and 2024:

(in millions, except average price paid per share)

ASR Agreement Initiation	Total Cost	Initial Shares Received	ASR Agreement Settlement	Additional Shares Received	Total Number of Shares Purchased	Average Price Paid per Share
March 2024	$ 354	1.7	May 2024	0.2	1.9	$ 182.65
May 2024	$ 505	1.8	July 2024	0.6	2.4	$ 211.40
June 2025	$ 404	1.1	August 2025	0.2	1.3	$ 311.84

Capped Call Options. In February 2025, we entered into two structured share repurchase agreements. Under these agreements, we made up-front cash payments totaling $150 million in exchange for the right to receive a predetermined amount of shares of our common stock or cash at expiration, depending upon the closing price of our common stock on the respective settlement dates. Any prepayments or cash payments at settlement were recorded in Common Stock on our Consolidated Balance Sheet and as a financing activity within our Consolidated Statement of Cash Flows. Neither option was exercised therefore we did not receive any shares at expiration. As a result, as of September 30, 2025, we received our initial up-front cash payments of $150 million plus a nominal cash premium. The cash received restored the remaining authority available for repurchases.

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

Changes in Accumulated Other Comprehensive Loss (All Registrants)

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

Three Months Ended September 30, 2025	Gains (losses) on Cash Flow Hedges	Pension and OPEB Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (3)	$ (2,263)	$ (6)	$ (2,272)
OCI before reclassifications	—	—	(8)	(8)
Amounts reclassified from AOCI	2	18	—	20
Net current-period OCI	2	18	(8)	12
Ending balance	$ (1)	$ (2,245)	$ (14)	$ (2,260)
Three Months Ended September 30, 2024				
Beginning balance	$ (8)	$ (2,125)	$ (28)	$ (2,161)
OCI before reclassifications	—	—	12	12
Amounts reclassified from AOCI	1	14	—	15
Net current-period OCI	1	14	12	27
Ending balance	$ (7)	$ (2,111)	$ (16)	$ (2,134)
Nine Months Ended September 30, 2025				
Beginning balance	$ (6)	$ (2,262)	$ (34)	$ (2,302)
OCI before reclassifications	—	(34)	20	(14)
Amounts reclassified from AOCI	5	51	—	56
Net current-period OCI	5	17	20	42
Ending balance	$ (1)	$ (2,245)	$ (14)	$ (2,260)
Nine Months Ended September 30, 2024				
Beginning balance	$ (10)	$ (2,157)	$ (24)	$ (2,191)
OCI before reclassifications	—	(4)	8	4
Amounts reclassified from AOCI	3	50	—	53
Net current-period OCI	3	46	8	57
Ending balance	$ (7)	$ (2,111)	$ (16)	$ (2,134)

(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 10 — Retirement Benefits for additional information. See our Consolidated Statements of Operations and Comprehensive Income for individual components of AOCI.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	2025	2024
Pension and OPEB plans:				
Actuarial loss reclassified to periodic benefit cost	$ (5)	$ (5)	$ (18)	$ (18)
Pension and OPEB plans valuation adjustment	—	—	12	2

(Dollars in millions, unless otherwise noted)

16. Variable Interest Entities

At September 30, 2025 and December 31, 2024, 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, 2025 and December 31, 2024. 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, 2025	December 31, 2024
Cash and cash equivalents	$ 69	$ 59
Restricted cash and cash equivalents	51	50
Accounts receivable		
Customer accounts receivable, net	2,225	2,134
Other accounts receivable, net	10	12
Inventories, net		
Materials and supplies	13	13
Other current assets	32	38
Total current assets	2,400	2,306
Property, plant, and equipment, net	1,970	2,025
Other noncurrent assets	127	142
Total noncurrent assets	2,097	2,167
Total assets[(a)]	$ 4,497	$ 4,473
Long-term debt due within one year	$ 66	$ 64
Accounts payable and accrued expenses	37	54
Other current liabilities	3	—
Total current liabilities	106	118
Long-term debt	589	642
Asset retirement obligations	228	206
Other noncurrent liabilities	2	2
Total noncurrent liabilities	819	850
Total liabilities	$ 925	$ 968

(a) Our balances include unrestricted assets for current unamortized energy contract assets of $19 million and $22 million, disclosed within other current assets in the table above and noncurrent unamortized energy contract assets of $120 million and $133 million, disclosed within other noncurrent assets in the table above as of September 30, 2025 and December 31, 2024, respectively.

(Dollars in millions, unless otherwise noted)

As of September 30, 2025 and December 31, 2024, 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 and gas. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. Refer to Note 7 — Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	We conduct all activities.

Unconsolidated VIEs

Our variable interests in unconsolidated VIEs generally include energy purchase and sale contracts. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in the Consolidated Balance Sheets that relate to our involvement with the VIEs are predominantly related to working capital accounts and generally represent the amounts owed by, or owed to, us for the deliveries associated with the current billing cycles under the commercial agreements.

As of September 30, 2025 and December 31, 2024, we had significant unconsolidated variable interests in several VIEs for which we were not the primary beneficiary. These interests include certain commercial agreements.

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

Commercial Agreement VIEs:	September 30, 2025	December 31, 2024
Total assets[a]	$ 712	$ 617
Total liabilities[a]	90	42
Other ownership interests in VIE[a]	622	575

(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.

(Dollars in millions, unless otherwise noted)

As of September 30, 2025 and December 31, 2024 the unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason we are not the primary beneficiary:
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.

17. Supplemental Financial Information

Supplemental Statement of Operations and Comprehensive Income Information

The following tables provide additional information about items recorded in the Consolidated Statements of Operations and Comprehensive Income.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating revenues	**2025**	**2024**	**2025**	**2024**
Variable lease income	$ 65	$ 69	$ 181	$ 189

	Three Months Ended September 30,		Nine Months Ended September 30,	
Taxes other than income taxes	**2025**	**2024**	**2025**	**2024**
Property	$ 74	$ 76	$ 216	$ 215
Payroll	44	48	128	122
Gross receipts[(a)]	46	37	123	102
Other	1	4	5	7
Total taxes other than income taxes	$ 165	$ 165	$ 472	$ 446

(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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Other, net	**2025**	**2024**	**2025**	**2024**
Decommissioning-related activities:				
Net realized income on NDT funds[(a)]				
Regulatory Agreement Units	$ 165	$ 203	$ 540	$ 460
Non-Regulatory Agreement Units	78	118	245	233
Net unrealized gains (losses) on NDT funds				
Regulatory Agreement Units	313	337	624	548
Non-Regulatory Agreement Units	200	190	430	329
Regulatory offset to NDT fund-related activities[(b)]	(383)	(433)	(935)	(808)
Total Decommissioning-related activities	373	415	904	762
Net unrealized gains (losses) from equity investments[(c)]	19	(104)	(256)	(115)
Other	51	14	81	46
Total Other, net	$ 443	$ 325	$ 729	$ 693

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities and the elimination of income taxes related to all NDT fund activity for the Regulatory Agreement Units.
(c) Includes unrealized gains (losses) resulting from an equity investment in a publicly traded company. We record the fair value of this investment in Investments on the Consolidated Balance Sheets based on quoted market price of the stock.

(Dollars in millions, unless otherwise noted)

Supplemental Cash Flow Information

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

Depreciation, amortization, and accretion	Income statement location	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
PP&E	Depreciation and amortization	$ 729	$ 850
Nuclear fuel	Purchased power and fuel	712	656
ARO accretion	Operating and maintenance	480	498
Amortization of intangible assets, net	Depreciation and amortization	14	18
Amortization of energy contract assets and liabilities	Operating revenues or purchased power and fuel	10	27
Total depreciation, amortization, and accretion		$ 1,945	$ 2,049

	CEG Parent		Constellation	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
Other non-cash operating activities	2025	2024	2025	2024
Other decommissioning-related activity[(a)]	$ (366)	$ (488)	$ (366)	$ (488)
Pension and non-pension postretirement benefit costs	115	81	115	81
Energy-related options[(b)]	(34)	40	(34)	40
Other	211	206	146	172
Total other non-cash operating activities	$ (74)	$ (161)	$ (139)	$ (195)

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

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

September 30, 2025	CEG Parent	Constellation
Cash and cash equivalents	$ 3,959	$ 3,949
Restricted cash and cash equivalents	132	88
Total cash, restricted cash, and cash equivalents	$ 4,091	$ 4,037
December 31, 2024		
Cash and cash equivalents	$ 3,022	$ 3,018
Restricted cash and cash equivalents	107	97
Total cash, restricted cash, and cash equivalents	$ 3,129	$ 3,115
September 30, 2024		
Cash and cash equivalents	$ 1,793	$ 1,793
Restricted cash and cash equivalents	89	77
Total cash, restricted cash, and cash equivalents	$ 1,882	$ 1,870

For additional information on restricted cash, see Note 1 — Basis of Presentation of our 2024 Form 10-K.

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

Supplemental Balance Sheet Information

The following table provides additional information about material items recorded in the Consolidated Balance Sheets.

	Accounts payable and accrued expenses	
September 30, 2025	**CEG Parent**	**Constellation**
Accounts payable	$ 2,509	$ 2,478
Compensation-related accruals[(a)]	781	556
Taxes accrued[(b)]	177	175
Other accrued expenses	459	459
Total	$ 3,926	$ 3,668
December 31, 2024		
Accounts payable	$ 2,369	$ 2,348
Compensation-related accruals[(a)]	907	689
Taxes accrued[(b)]	232	223
Other accrued expenses	435	436
Total	$ 3,943	$ 3,696

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation, and benefits.
(b) Includes $270 million and $150 million as of September 30, 2025 and December 31, 2024, respectively, related to nuclear PTC that was used to offset the current tax liability. See Note 6 — Government Assistance for additional information on the nuclear PTC.

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

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

Executive Overview

We are the nation's largest producer of carbon-free 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, public sector, and residential customers in markets across multiple geographic regions. We have five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions.

Significant Transactions and Developments

Conowingo Hydroelectric Project License Renewal

In September 2025, we reached a settlement agreement with MDE, Lower Susquehanna Riverkeeper Association, and Waterkeepers Chesapeake, that resolves all outstanding issues related to obtaining a water quality certification from MDE. As a result, MDE issued a water quality certification, clearing the way for the re-licensing and continued operation of our Conowingo hydroelectric facility. The terms of the agreement include operational improvements and commitments for water quality and resiliency, trash and debris removal, aquatic life passage, freshwater mussel restoration, dredging and invasive species management. See Note 3 — Regulatory Matters for more information.

One Big Beautiful Bill Act

We continue to see legislative support for nuclear energy generation, including the passage of the OBBBA. Signed into law in July 2025, the OBBBA both preserves certain federal tax credits from the IRA and enhances certain credits to allow advanced nuclear facilities to qualify for the energy communities bonus adder, subject to

eligibility requirements. Overall, the OBBBA reinforces the long-term economic viability of our nuclear generation assets. See Note 3 — Regulatory Matters for more information.

Clinton Clean Energy Center

In June 2025, we signed a 20-year PPA with Meta Platforms, Inc. (Meta) for the output of the Clinton Clean Energy Center to support Meta's clean energy goals and operations in the region with emissions-free nuclear energy. The agreement, beginning in June 2027, supports the relicensing and continued operations of Clinton for another two decades after the state's ZEC program expires. This deal will expand Clinton's clean energy output by 30 megawatts through plant uprates, expected to be fully complete in 2029, and will enable the Clinton Clean Energy Center to continue to flow power onto the local grid, providing grid reliability and low-cost power to the region for decades to come. The uprates are expected to qualify for the technology-neutral clean electricity PTC (45Y) provided for by the IRA and preserved by the OBBBA for its first 10 years of operations.

Proposed Acquisition of Calpine Corporation

On January 10, 2025, we entered an agreement and plan of merger (Merger Agreement) with Calpine Corporation (Calpine) under which we will acquire all the outstanding equity interests of Calpine in a cash and stock transaction. Calpine owns and operates a generation fleet of natural gas, geothermal, battery storage, and solar assets with over 27 GWs of generation capacity, in addition to a competitive retail electric supplier platform with 60 TWhs of load annually.

This acquisition is complementary to, and aligns strategically with, our existing business operations and provides both increased scale and meaningful market diversification. We will couple the largest producer of clean, carbon-free energy with the reliable, dispatchable natural gas assets of Calpine, and also create the nation's leading competitive retail electric supplier, providing increased scale, diversification and complementary capabilities that will enable us to meet growing demand with a broader array of energy and sustainability products. The addition of Calpine will strengthen our essential role in providing clean, reliable, and affordable energy as the nation seeks to transition to a more sustainable future, and will better position us to pursue investments in new and existing technologies to meet growing demand.

We received regulatory approvals for the merger from the PUCT and NYPSC in June 2025 and from the FERC in July 2025. Completion of the transaction is subject to the expiration or termination of any agreement with the DOJ to delay the consummation of the transaction and other customary closing conditions. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Other Key Business Drivers

Tariffs

The energy sector has been impacted by changes in U.S. and foreign trade policies, particularly the introduction and adjustment of tariffs by the U.S. on the import of various energy-related products and materials. Importantly, oil, natural gas, and uranium (including enriched uranium) are currently excluded from most of the recent tariff changes. The imposition of tariffs on imported goods, including electric transformers and other equipment used for power generation, may lead to increased costs for acquiring essential components to maintain, uprate, and operate our generating facilities. We are committed to navigating the current environment through prudent cost management, utilization of supplier relationships, and potential supply alternatives as mitigants for potential price increases. The long-term impact of tariffs on the energy sector remains uncertain and we cannot predict or estimate the impact on future consolidated financial statements.

Russia and Ukraine Conflict

We are closely monitoring developments of the ongoing Russia and Ukraine conflict, including United States, United Kingdom, European Union, and Canadian sanctions, and legislation that may impact exports and imports of Russian nuclear fuel supply and enrichment activities, as well as the potential for Russia to limit fuel deliveries. The U.S. "Prohibiting Russian Uranium Imports Act" became effective in August 2024, banning the import of low-enriched uranium into the U.S. that is produced in Russia or by Russian entities, absent a waiver from the DOE. Under a corollary bill, the Department of Energy has begun the process of distributing billions of dollars to

support expansion of the domestic nuclear fuel cycle within the United States to improve carbon-free energy security. In November 2024, the Russian government issued a decree imposing temporary restrictions on the export of enriched uranium from Russia to the U.S. but allowing for a special Russian export license to be issued for individual shipments. 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 to support our refueling needs and mitigate the risk of exposure to Russian nuclear fuel supply. Recognizing the potential for the continuing conflict to impact our longer-term security and cost of supply, we have entered into contracts to increase the size of our nuclear fuel inventory. Our fuel procurement activities comply with all U.S. and international trade laws and we continue to take advantage of all available avenues to maintain continuity in our nuclear fuel supply, including working with the U.S. Government and our diverse set of suppliers to secure the nuclear fuel needed to continue to operate our nuclear fleet long-term.

Environmental Regulation

Regulation of GHGs from Power Plants under the Clean Air Act. In April 2024, EPA issued a final rule that regulates greenhouse gases from existing coal, new natural gas-fired power plants, and existing oil/gas steam generators under Clean Air Act section 111. The applicable standards are subcategorized by retirement date for existing coal and capacity factor for new gas. In June 2025, EPA issued a proposal to repeal its regulations addressing GHG emissions from the sector. In July 2025, EPA issued a proposed rule to repeal the 2009 "Endangerment Finding" underpinning all GHG regulation by EPA. Repealing the finding would provide an independent basis for ending EPA regulation of GHGs from power plants.

Good Neighbor Rule. In June 2023, EPA published a final rule called “Federal 'Good Neighbor Plan' for the 2015 Ozone National Ambient Air Quality Standards” also known as the "Transport Rule". The rule, among other things, establishes nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 23 states to participate in an allowance-based ozone season trading program beginning in 2023. In February 2023, EPA disapproved state implementation plans submitted by 21 states for failure to address their obligations under the "good neighbor" provisions of the Clean Air Act. However, several Regional Courts of Appeals issued orders staying, pending judicial review, EPA's disapproval of several state plans (including Texas). In June 2024, the Supreme Court stayed EPA's rule for the duration of the litigation. In November 2024, EPA issued an administrative stay of the rule. EPA has announced its intent to approve state plans that would replace the Good Neighbor Plan.

Critical Accounting Policies and Estimates

Management makes a number of significant estimates, assumptions, and judgments in the preparation of our financial statements. At September 30, 2025, our critical accounting policies and estimates had not changed significantly from December 31, 2024. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates of our 2024 Form 10-K for further information.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth our consolidated GAAP Net Income (Loss) Attributable to Common Shareholders for the three and nine months ended September 30, 2025 compared to the same period in 2024. For additional information regarding the financial results for the three and nine months ended September 30, 2025 and 2024, see the discussions of Results of Operations below.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2025	2024	$ Change	2025	2024	$ Change
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 930	$ 1,200	$ (270)	$ 1,887	$ 2,897	$ (1,010)

Adjusted (non-GAAP) Operating Earnings. We utilize Adjusted (non-GAAP) Operating Earnings (and/or its per share equivalent) in our internal analysis, and in communications with investors and analysts, as a consistent measure for comparing our financial performance and discussing the factors and trends affecting our business. The presentation of Adjusted (non-GAAP) Operating Earnings is intended to complement and should not be considered an alternative to, nor more useful than, the presentation of GAAP Net Income.

The table below provides a reconciliation of GAAP Net Income to Adjusted (non-GAAP) Operating Earnings. Adjusted (non-GAAP) Operating Earnings is not a standardized financial measure and may not be comparable to other companies' presentations of similarly titled measures.

Unless otherwise noted, the income tax impact of each reconciling adjustment between GAAP Net Income (Loss) Attributable to Common Shareholders and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all adjustments except the NDT fund investment returns, which are included in decommissioning-related activities, the marginal statutory income tax rate was 25.6% and 25.5% for the three and nine months ended September 30, 2025 and 2024, respectively. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized and realized gains and losses related to NDT funds were 54.9% and 54.6% for the three months ended September 30, 2025 and 2024, respectively and 54.8% and 55.3% for the nine months ended September 30, 2025 and 2024, respectively. The following table provides a reconciliation between GAAP Net Income (Loss) Attributable to Common Shareholders and Adjusted (non-GAAP) Operating Earnings for the three and nine months ended September 30, 2025 compared to the same period in 2024.

	Three Months Ended September 30,			
	2025		2024	
(In millions, except per share data)		Earnings Per Share[(a)]		Earnings Per Share[(a)]
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 930	$ 2.97	$ 1,200	$ 3.82
Unrealized (Gain) Loss on Fair Value Adjustments (net of taxes of $32 and $72, respectively)[(b)]	94	0.30	(210)	(0.67)
Plant Retirements and Divestitures (net of taxes of $2 and $10, respectively)	(5)	(0.02)	30	0.10
Decommissioning-Related Activities (net of taxes of $187 and $207, respectively)[(c)]	(117)	(0.37)	(195)	(0.62)
Pension & OPEB Non-Service (Credits) Costs (net of taxes of $3 and $1, respectively)	9	0.03	(2)	(0.01)
Acquisition-Related Costs (net of taxes of $10 and $—, respectively)[(d)]	28	0.09	—	—
Change in Environmental Liabilities (net of taxes of $— and $2, respectively)	1	—	5	0.02
ERP System Implementation Costs (net of taxes of $— and $—, respectively)	—	—	1	—
Income Tax-Related Adjustments[(e)]	13	0.04	33	0.11
Noncontrolling Interests[(f)]	(1)	—	(2)	(0.01)
Adjusted (non-GAAP) Operating Earnings	$ 952	$ 3.04	$ 860	$ 2.74

(In millions, except per share data)	Nine Months Ended September 30, 2025	2025 Earnings Per Share[(a)]	2024	2024 Earnings Per Share[(a)]
GAAP Net Income (Loss) Attributable to Common Shareholders	$ 1,887	$ 6.02	$ 2,897	$ 9.17
Unrealized (Gain) Loss on Fair Value Adjustments (net of taxes of $163 and $264, respectively)[(b)]	478	1.52	(786)	(2.49)
Plant Retirements and Divestitures (net of taxes of $4 and $23, respectively)	13	0.04	68	0.22
Decommissioning-Related Activities (net of taxes of $426 and $343, respectively)[(c)]	(242)	(0.77)	(227)	(0.72)
Pension & OPEB Non-Service (Credits) Costs (net of taxes of $9 and $1, respectively)	27	0.09	2	0.01
Acquisition-Related Costs (net of taxes of $17 and $—, respectively)[(d)]	50	0.16	—	—
Change in Environmental Liabilities (net of taxes of $1 and $20, respectively)	2	0.01	60	0.19
Separation Costs (net of taxes of $— and $3, respectively)	—	—	9	0.03
ERP System Implementation Costs (net of taxes of $— and $2, respectively)	—	—	7	0.02
Income Tax-Related Adjustments[(e)]	13	0.04	(55)	(0.17)
Noncontrolling Interests[(f)]	(4)	(0.01)	(5)	(0.02)
Adjusted (non-GAAP) Operating Earnings	$ 2,224	$ 7.09	$ 1,970	$ 6.23

(a) Amounts may not sum due to rounding. Earnings per share amount is based on average diluted common shares outstanding of 313 million and 314 million for the three months ended September 30, 2025 and 2024, respectively and 314 million and 316 million for the nine months ended September 30, 2025 and 2024, respectively.
(b) Includes mark-to-market on economic hedges, interest rate swaps, and fair value adjustments related to gas imbalances and equity investments.
(c) Reflects all gains and losses associated with NDTs, ARO accretion, ARC depreciation, ARO remeasurement, and impacts of contractual offset for Regulatory Agreement Units.
(d) In 2025, reflects acquisition-related costs associated with the proposed Calpine merger.
(e) Adjustment to deferred income taxes due to changes in forecasted apportionment.
(f) Represents elimination of the noncontrolling interest portion of certain adjustments included above.

Results of Operations

	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	$ Change	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024	$ Change
Operating revenues	$ 6,570	$ 6,550	$ 20	$ 19,459	$ 18,186	$ 1,273
Operating expenses						
Purchased power and fuel	3,567	3,119	448	11,083	8,828	2,255
Operating and maintenance	1,511	1,535	(24)	4,673	4,666	7
Depreciation and amortization	241	266	(25)	743	868	(125)
Taxes other than income taxes	165	165	—	472	446	26
Total operating expenses	5,484	5,085	399	16,971	14,808	2,163
Gain (loss) on sales of assets and businesses	—	2	(2)	—	2	(2)
Operating income (loss)	1,086	1,467	(381)	2,488	3,380	(892)
Other income and (deductions)						
Interest expense, net	(134)	(147)	13	(398)	(416)	18
Other, net	443	325	118	729	693	36
Total other income and (deductions)	309	178	131	331	277	54
Income (loss) before income taxes	1,395	1,645	(250)	2,819	3,657	(838)
Income tax (benefit) expense	466	449	17	928	768	160
Equity in income (losses) of unconsolidated affiliates	—	—	—	—	(1)	1
Net income (loss)	929	1,196	(267)	1,891	2,888	(997)
Net income (loss) attributable to noncontrolling interests	(1)	(4)	3	4	(9)	13
Net income (loss) attributable to common shareholders	$ 930	$ 1,200	$ (270)	$ 1,887	$ 2,897	$ (1,010)

Three Months Ended September 30, 2025 Compared to Three Months Ended September 30, 2024. The variance in Net income (loss) attributable to common shareholders was unfavorable by ($270) million primarily due to:

- Lower Nuclear PTC revenues in 2025. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information; and
- Unfavorable net unrealized losses on economic hedges.

The unfavorable items were partially offset by:

- Favorable market and portfolio conditions primarily driven by higher capacity revenues and generation-to-load optimization; and
- Higher net unrealized gains on equity investments.

Nine Months Ended September 30, 2025 Compared to Nine Months Ended September 30, 2024. The variance in Net income (loss) attributable to common shareholders was unfavorable by ($1,010) million primarily due to:

- Lower Nuclear PTC revenues in 2025. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information;
- Unfavorable net unrealized losses on economic hedges; and
- Higher net unrealized losses on equity investments.

The unfavorable items were partially offset by:

- Favorable market and portfolio conditions primarily driven by higher capacity revenues and generation-to-load optimization;
- Favorable net ZEC revenues, including the impacts of higher revenue recognized for ZECs delivered under the Illinois ZEC program in prior planning years; and
- Favorable net realized and unrealized NDT fund investment activity.

Operating revenues. 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.

Wholesale and retail sales of natural gas, as well as sales of other energy-related products and sustainable solutions and other miscellaneous business activities that are not significant to overall results of operations are reported under Other and not allocated to a region.

For the three and nine months ended September 30, 2025 compared to 2024, Operating revenues were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2025	2024	$ Change	% Change[a]	2025	2024	$ Change	% Change[a]
Mid-Atlantic	$ 1,763	$ 1,603	$ 160	10.0 %	$ 4,876	$ 4,148	$ 728	17.6 %
Midwest	1,390	1,275	115	9.0 %	4,317	3,537	780	22.1 %
New York	558	507	51	10.1 %	1,655	1,534	121	7.9 %
ERCOT	628	523	105	20.1 %	1,489	1,201	288	24.0 %
Other Power Regions	1,543	1,443	100	6.9 %	4,277	4,252	25	0.6 %
Total reportable segment electric revenues	5,882	5,351	531	9.9 %	16,614	14,672	1,942	13.2 %
Other	844	683	161	23.6 %	3,201	2,745	456	16.6 %
Mark-to-market gains (losses)	(156)	516	(672)		(356)	769	(1,125)	
Total Operating revenues	$ 6,570	$ 6,550	$ 20	0.3 %	$ 19,459	$ 18,186	$ 1,273	7.0 %

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

Sales and Supply Sources. Our sales and supply volumes (GWhs) by region are summarized below:

(GWhs)	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	Change	% Change	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024	Change	% Change
Nuclear Generation[a]								
Mid-Atlantic	13,665	13,420	245	1.8 %	39,105	39,839	(734)	(1.8)%
Midwest	23,644	23,835	(191)	(0.8)%	71,000	71,381	(381)	(0.5)%
New York	6,671	5,893	778	13.2 %	19,585	18,657	928	5.0 %
ERCOT	2,497	2,362	135	5.7 %	7,541	6,340	1,201	18.9 %
Total Nuclear Generation	46,477	45,510	967	2.1 %	137,231	136,217	1,014	0.7 %
Natural Gas, Oil, and Renewables								
Mid-Atlantic	242	329	(87)	(26.4)%	1,683	1,809	(126)	(7.0)%
Midwest	141	151	(10)	(6.6)%	785	774	11	1.4 %
ERCOT	4,325	4,783	(458)	(9.6)%	10,615	11,890	(1,275)	(10.7)%
Other Power Regions	1,466	1,850	(384)	(20.8)%	4,556	7,017	(2,461)	(35.1)%
Total Natural Gas, Oil, and Renewables	6,174	7,113	(939)	(13.2)%	17,639	21,490	(3,851)	(17.9)%
Purchased Power								
Mid-Atlantic	5,416	6,022	(606)	(10.1)%	13,960	12,707	1,253	9.9 %
Midwest	403	107	296	276.6 %	1,366	639	727	113.8 %
ERCOT	714	771	(57)	(7.4)%	2,209	2,496	(287)	(11.5)%
Other Power Regions	11,451	10,813	638	5.9 %	32,295	30,855	1,440	4.7 %
Total Purchased Power	17,984	17,713	271	1.5 %	49,830	46,697	3,133	6.7 %
Total Supply/Sales by Region								
Mid-Atlantic	19,323	19,771	(448)	(2.3)%	54,748	54,355	393	0.7 %
Midwest	24,188	24,093	95	0.4 %	73,151	72,794	357	0.5 %
New York	6,671	5,893	778	13.2 %	19,585	18,657	928	5.0 %
ERCOT	7,536	7,916	(380)	(4.8)%	20,365	20,726	(361)	(1.7)%
Other Power Regions	12,917	12,663	254	2.0 %	36,851	37,872	(1,021)	(2.7)%
Total Supply/Sales by Region	70,635	70,336	299	0.4 %	204,700	204,404	296	0.1 %

(a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for our plants that reflects our ownership percentage for stations operated by us and excludes Salem and STP, which are operated by PSEG and STPNOC, respectively. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a unit (or combination of units) over a period of time to its output if the unit had operated at 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,	
	2025	2024	2025	2024
Nuclear fleet capacity factor	96.8 %	95.0 %	95.3 %	94.6 %
Refueling outage days	23	37	152	164
Non-refueling outage days	5	20	27	33

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, ongoing 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.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Location (Region)	2025	2024	$ Change	% Change	2025	2024	$ Change	% Change
PJM West (Mid-Atlantic)	$ 46.77	$ 36.98	$ 9.79	26.5 %	$ 47.63	$ 33.41	$ 14.22	42.6 %
ComEd (Midwest)	42.72	28.92	13.80	47.7 %	36.37	25.80	10.57	41.0 %
Central (New York)	49.51	33.30	16.21	48.7 %	54.07	31.80	22.27	70.0 %
North (ERCOT)	35.05	26.61	8.44	31.7 %	33.06	27.75	5.31	19.1 %
Southeast Massachusetts (Other)[(a)]	50.43	38.37	12.06	31.4 %	65.16	37.34	27.82	74.5 %

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

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 material impact on our operating revenues and purchased power and fuel expense. We report capacity on a net monthly basis within each region in either Operating revenues or Purchased power and fuel expense, depending on our net monthly position. The following table presents the average capacity prices ($/MW Day) for each of our major regions. Prices reflect the weighted average prices for the various auction periods within the three and nine months ended September 30, 2025 and 2024.

Location (Region)	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	$ Change	% Change	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024	$ Change	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic)	$ 269.92	$ 53.60	$ 216.32	403.6 %	$ 149.74	$ 51.32	$ 98.42	191.8 %
ComEd (Midwest)	269.92	28.92	241.00	833.3 %	136.03	31.81	104.22	327.6 %
Rest of State (New York)	193.33	132.22	61.11	46.2 %	137.52	112.78	24.74	21.9 %
Southeast New England (Other)	87.97	949.57	(861.60)	(90.7)%	566.63	459.07	107.56	23.4 %

ZEC Prices. We are compensated through state programs for the carbon-free attributes of our nuclear generation. The following table includes the average ZEC reference prices ($/MWh) for each of our major regions in which state programs have been enacted. Gross prices reflect the weighted average price for the various delivery periods within the three and nine months ended September 30, 2025 and 2024 and may not necessarily reflect prices we ultimately realize as a result of interaction with the nuclear PTC discussed below.

State (Region)[(a)]	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	$ Change	% Change	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024	$ Change	% Change
New Jersey (Mid-Atlantic)[(b)]	$ —	$ 10.00	$ (10.00)	(100.0)%	$ 10.00	$ 9.97	$ 0.03	0.3 %
Illinois (Midwest)	1.17	9.38	(8.21)	(87.5)%	5.73	4.34	1.39	32.0 %
New York (New York)	14.76	18.27	(3.51)	(19.2)%	15.93	18.27	(2.34)	(12.8)%

(a) See ITEM 1. BUSINESS, Environmental Matters of our 2024 Form 10-K for additional information on the plants receiving payments through state programs.
(b) The New Jersey ZEC program ended in May 2025.

Illinois CMC Price. The price received (paid) for each CMC is determined by the IPA monthly by subtracting energy and capacity index prices from the bid price, which resulted in $32.50 per MWh for the period June 2023 through May 2024, $33.43 per MWh for the period June 2024 through May 2025 and $33.50 per MWh for the period June 2025 through May 2026. 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. The average CMC prices per MWh were ($17.11) and $5.54 for the three months ended September 30, 2025 and 2024, respectively, and ($6.53) and $7.73 for the nine months ended September 30, 2025 and 2024, respectively. The average CMC prices may not necessarily reflect prices we ultimately realize as a result of interaction with the nuclear PTC discussed below.

Nuclear PTC. Beginning in 2024, our nuclear units are eligible for a PTC extending through 2032. The nuclear PTC provides a transferable credit up to $15 per MWh and is subject to phase-out when annual gross receipts are between $25.00 per MWh and $43.75 per MWh and $26.00 per MWh and $44.75 per MWh for 2024 and 2025, respectively. Both the amount of the PTC and the gross receipts thresholds adjust for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year.

Many of the state-sponsored programs (e.g., ZECs and CMCs) providing compensation for the emissions-free attributes of generation from certain of our nuclear units include contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information on the nuclear PTC.

The following table summarizes the impacts to Operating revenues related to the benefits of nuclear PTC and state-sponsored programs subject to refund or pass through as described above for the three and nine months ended September 30, 2025 compared to 2024:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2025	2024	$ Change	% Change	2025	2024	$ Change	% Change
Nuclear PTC revenue[a]	$ 175	$ 670	$ (495)	(73.9)%	$ 220	$ 1,380	$ (1,160)	(84.1)%
State-sponsored programs net revenue[b]	(220)	(115)	(105)	(91.3)%	(30)	10	(40)	(400.0)%

(a) Our estimate required the exercise of judgment in determining the amount of nuclear PTC expected for each of our nuclear units. Refer to Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Includes only state-sponsored programs that have contractual or other provisions that require us to refund that compensation up to the amount of the nuclear PTC received or pass through the entirety of the nuclear PTC received.

For the three and nine months ended September 30, 2025 compared to 2024, changes in **Operating revenues** by region were approximately as follows:

	Three Months Ended September 30			Nine Months Ended September 30		
	$ Change	% Change[a]	Description	$ Change	% Change[a]	Description
Mid-Atlantic	$ 160	10.0 %	• favorable retail load revenue of $185 primarily due to higher contracted energy prices and load volumes • favorable wholesale load revenue of $80 primarily due to higher contracted energy prices; partially offset by • absence of nuclear PTC revenue of ($160) due to higher energy prices in the current year	$ 728	17.6 %	• favorable retail load revenue of $445 primarily due to higher contracted energy prices and load volumes • favorable realized economic hedges of $410 due to settled prices relative to hedged prices • favorable wholesale load revenue of $200 primarily due to higher contracted energy prices; partially offset by • absence of nuclear PTC revenue of ($340) due to higher energy prices in the current year

	Three Months Ended September 30			Nine Months Ended September 30		
	$ Change	% Change[(a)]	Description	$ Change	% Change[(a)]	Description
Midwest	115	9.0 %	• favorable retail load revenue of $190 primarily due to higher contracted energy prices and load volumes • favorable realized economic hedges of $175 due to settled prices relative to hedged prices • favorable net generation and wholesale load revenue of $130 primarily due to higher load volumes and contracted energy prices • favorable net capacity revenue of $90 due to higher capacity prices; partially offset by • lower nuclear PTC revenue of ($280) and CMC program revenue of ($155) due to higher energy prices in the current year	780	22.1 %	• favorable net generation and wholesale load revenue of $500 primarily due to higher load volumes and contracted energy prices • favorable realized economic hedges of $540 due to settled prices relative to hedged prices • favorable retail load revenue of $310 primarily due to higher contracted energy prices and load volumes • favorable net ZEC revenue of $180 primarily due to revenue recognized for Illinois ZECs delivered in prior planning years and increase in ZEC price • favorable net capacity revenue of $110 due to higher capacity prices; partially offset by • lower nuclear PTC revenue of ($710) and CMC program revenue of ($160) due to higher energy prices in the current year
New York	51	10.1 %	• favorable net generation revenue of $70 primarily due to higher energy prices • favorable ZEC program revenue of $50 primarily due to the absence of nuclear PTC revenue; partially offset by • absence of nuclear PTC revenue of ($60) due to higher energy prices in the current year	121	7.9 %	• favorable net generation revenue of $185 primarily due to higher energy prices • favorable ZEC program revenue of $90 primarily due to the absence of nuclear PTC revenue • favorable retail load revenue of $85 primarily due to higher contracted energy prices; partially offset by • absence of nuclear PTC revenue of ($120) due to higher energy prices in the current year • unfavorable realized economic hedges of ($115) due to settled prices relative to hedged prices

	Three Months Ended September 30			Nine Months Ended September 30		
	$ Change	% Change[a]	Description	$ Change	% Change[a]	Description
ERCOT	105	20.1 %	• favorable wholesale load revenue of $45 primarily due to higher contracted energy prices	288	24.0 %	• favorable realized economic hedges of $110 due to settled prices relative to hedged prices • favorable wholesale load revenue of $95 primarily due to higher contracted energy prices • favorable retail load revenue of $65 primarily due to higher contracted energy prices
Other Power Regions	100	6.9 %	• favorable net wholesale load revenue of $80 primarily due to higher contracted energy prices	25	0.6 %	• No individually significant drivers
Other	161	23.6 %	• favorable revenues in the United Kingdom, inclusive of realized economic hedges, of $100 primarily due to higher energy prices • favorable retail gas revenue of $65 primarily due to higher gas prices	456	16.6 %	• favorable retail gas revenue of $305 primarily due to higher gas prices • favorable revenues in the United Kingdom, inclusive of realized economic hedges, of $180 primarily due to higher energy prices
Mark-to-market[b]	(672)		• losses on economic hedging activities of ($156) in 2025 compared to gains of $516 in 2024	(1,125)		• losses on economic hedging activities of ($356) in 2025 compared to gains of $769 in 2024
Total	$ 20	0.3 %		$ 1,273	7.0 %	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 11 — 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 sales and supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

Wholesale and retail natural gas activity, as well as other miscellaneous business activities that are not significant to overall results of operations are reported under Other and are not allocated to a region.

For the three and nine months ended September 30, 2025 compared to 2024, Purchased power and fuel expense were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2025	2024	$ Change	% Change[(a)]	2025	2024	$ Change	% Change[(a)]
Mid-Atlantic	$ 871	$ 794	$ 77	9.7 %	$ 2,393	$ 1,906	$ 487	25.6 %
Midwest	447	391	56	14.3 %	1,489	1,185	304	25.7 %
New York	159	150	9	6.0 %	458	460	(2)	(0.4)%
ERCOT	213	120	93	77.5 %	589	375	214	57.1 %
Other Power Regions	1,200	1,010	190	18.8 %	3,560	3,157	403	12.8 %
Total electric purchased power and fuel	2,890	2,465	425	17.2 %	8,489	7,083	1,406	19.9 %
Other	702	537	165	30.7 %	2,664	2,149	515	24.0 %
Mark-to-market losses (gains)	(25)	117	(142)		(70)	(404)	334	
Total Purchased power and fuel	$ 3,567	$ 3,119	$ 448	14.4 %	$ 11,083	$ 8,828	$ 2,255	25.5 %

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

For the three and nine months ended September 30, 2025 compared to 2024, changes in **Purchased power and fuel** expense by region were approximately as follows:

	Three Months Ended September 30			Nine Months Ended September 30		
	$ Change	% Change[(a)]	Description	$ Change	% Change[(a)]	Description
Mid-Atlantic	$ 77	9.7 %	• unfavorable cost of ($105) associated with purchased power to supply load relative to generation volumes primarily due to higher energy prices and net capacity expense	$ 487	25.6 %	• unfavorable cost of ($465) associated with purchased power to supply load relative to generation volumes primarily due to higher energy prices, lower generation volumes, and higher net capacity expense
Midwest	56	14.3 %	• unfavorable cost of ($40) associated with purchased power to supply load relative to generation volumes primarily driven by higher energy prices	304	25.7 %	• unfavorable cost of ($270) associated with purchased power to supply load relative to generation volumes primarily driven by higher transmission costs and higher energy prices

	Three Months Ended September 30			Nine Months Ended September 30		
	$ Change	% Change[a]	Description	$ Change	% Change[a]	Description
New York	9	6.0 %	• No individually significant drivers	(2)	(0.4)%	• No individually significant drivers
ERCOT	93	77.5 %	• unfavorable cost of ($60) associated with purchased power to supply load relative to generation volumes primarily due to higher energy prices	214	57.1 %	• unfavorable cost of ($160) associated with purchased power to supply load relative to generation volumes primarily due to higher energy prices • unfavorable realized economic hedges of ($60) due to settled prices relative to hedged prices
Other Power Regions	190	18.8 %	• unfavorable purchased power of ($240) primarily due to higher energy prices; partially offset by • favorable realized economic hedges of $65 due to settled prices relative to hedged prices	403	12.8 %	• unfavorable purchased power of ($1,080) primarily due to lower generation volumes driven by the retirement of Mystic Units 8 and 9 and higher energy prices; partially offset by • favorable realized economic hedges of $730 due to settled prices relative to hedged prices
Other	165	30.7 %	• unfavorable purchases in the United Kingdom, inclusive of settled economic hedges, of ($110) primarily due to higher energy prices • unfavorable net wholesale gas purchases, inclusive of realized economic hedges, of ($40) primarily due to higher gas prices	515	24.0 %	• unfavorable net wholesale gas purchases, inclusive of realized economic hedges, of ($250) primarily due to higher gas prices • unfavorable purchases in the United Kingdom, inclusive of realized economic hedges, of ($205) primarily due to higher energy prices • unfavorable fair value adjustments related to gas imbalances of ($60)
Mark-to-market[b]	(142)		• gains on economic hedging activities of $25 in 2025 compared to losses of ($117) in 2024	334		• gains on economic hedging activities of $70 in 2025 compared to gains of $404 in 2024
Total	$ 448	14.4 %		$ 2,255	25.5 %	

(a) % Change in mark-to-market is not a meaningful measure.
(b) See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

Effective income tax rates were 33.4% and 27.3% for the three months ended September 30, 2025 and 2024, respectively and 32.9% and 21.0% for the nine months ended September 30, 2025 and 2024, respectively. The change in effective tax rate for 2025 is primarily due to the decrease in nuclear PTCs generated, which are not taxable, as well as higher qualified NDT fund income which is taxed at a higher rate. See Note 9 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

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 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, such as our acquisition of Calpine. A broad spectrum of financing alternatives beyond the core financing options can be used to meet our needs and fund growth, including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). Our access to external financing on reasonable terms depends on our credit ratings and current overall capital market business conditions. If these conditions deteriorate to the extent that we no longer have access to the capital markets at reasonable terms, we have access to credit facilities with aggregate bank commitments of $9.5 billion. We utilize our credit facilities to support our commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the “Credit Matters and Cash Requirements” section below for additional information. We expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Cash Flow Activities

The following table summarizes our cash flow activities for the nine months ended September 30, 2025 and 2024, respectively:

	Nine Months Ended September 30,		
	2025	2024	$ Change
Cash, restricted cash, and cash equivalents at beginning of period	$ 3,129	$ 454	$ 2,675
Net cash provided by (used in):			
Operating activities	3,432	(1,448)	4,880
Investing activities	(2,221)	5,056	(7,277)
Financing activities	(249)	(2,180)	1,931
Net increase (decrease) in cash, restricted cash, and cash equivalents	962	1,428	(466)
Cash, restricted cash, and cash equivalents at end of period	$ 4,091	$ 1,882	$ 2,209

Net Cash Provided By (Used In) Operating Activities

Cash provided by operating activities was $3,432 million for the nine months ended September 30, 2025, compared to cash used in operating activities of ($1,448) million for the nine months ended September 30, 2024. Changes in our cash flows from operations were generally consistent with changes in results of operations, as adjusted for changes in working capital in the normal course of business. In December 2024, we amended our Accounts Receivable Facility whereby we now retain the rights to our receivables and any changes in our receivable balance flow through operating activities. This increase in cash flows from operating activities was partially offset by cash outflows associated with an increase in collateral postings. See Note 7 — Accounts Receivable and Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Net Cash Provided By (Used In) Investing Activities

Cash used in investing activities was ($2,221) million for the nine months ended September 30, 2025, compared to cash provided by investing activities of $5,056 million for the nine months ended September 30, 2024. The change was primarily due to an amendment of our Accounts Receivable Facility. Prior to the amendment, the collection and reinvestment of proceeds associated with the sale of receivables were treated as cash flows from investing activities in the Consolidated Statements of Cash Flows. As a result of the amendment, cash collections of accounts receivable are now treated as Cash flows from operating activities in the Consolidated Statement of Cash Flows. See Note 7 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Net Cash Provided By (Used In) Financing Activities

Cash used in financing activities was ($249) million for the nine months ended September 30, 2025, compared to cash used in financing activities of ($2,180) million for the nine months ended September 30, 2024. The change primarily relates to long-term debt and changes in short-term borrowings. Debt issuances and redemptions or repayments vary each year. The remaining change relates to repurchases of common stock during each period. See Note 12 — Debt and Credit Agreements and Note 15 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

Quarterly dividends declared by our Board of Directors during the nine months ended September 30, 2025 and for the fourth quarter of 2025 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share
First Quarter of 2025	February 18, 2025	March 7, 2025	March 18, 2025	$ 0.3878
Second Quarter of 2025	April 29, 2025	May 16, 2025	June 6, 2025	$ 0.3878
Third Quarter of 2025	August 5, 2025	August 18, 2025	September 5, 2025	$ 0.3878
Fourth Quarter of 2025	October 29, 2025	November 17, 2025	December 5, 2025	$ 0.3878

Credit Matters and Cash Requirements

We fund liquidity needs for capital expenditures, working capital, energy hedging and other financial commitments through cash flows from operations, public debt offerings, commercial paper markets and large, diversified credit facilities. As of September 30, 2025, we have access to facilities with aggregate bank commitments of $9.5 billion. During the quarter, we amended one of our existing revolving credit facilities to both extend the term of the existing facility and to provide up to $2.5 billion in incremental revolving credit commitments upon the satisfaction of certain conditions following the consummation of our acquisition of Calpine. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

We had access to the commercial paper markets and had availability under our revolving credit facilities during the third quarter of 2025 to fund our short-term liquidity needs, when necessary. 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 2024 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, including the cash consideration necessary to close on our proposed acquisition of Calpine. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

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. A loss of investment grade credit rating would have required a three-notch downgrade by S&P or Moody's from their current levels as of September 30, 2025 of BBB+ and Baa1, to BB+ and Ba1 or below, respectively. As of September 30, 2025, we had $7.3 billion of available capacity under our credit facilities and $4.0 billion of cash on hand. In the event of a credit downgrade below investment grade and a resulting requirement to provide incremental collateral exceeding available capacity under our credit facilities and cash on hand, we would be required to access additional liquidity through the capital markets. Our borrowings are not subject to default or prepayment as a result of a downgrade of our securities, although such a downgrade could increase fees and interest charges under our credit agreements. Our credit ratings were affirmed following the announcement of our proposed acquisition of Calpine.

If we had lost our investment grade credit ratings as of September 30, 2025, we would have been required to provide incremental collateral estimated to be approximately $2.4 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.

See Note 11 — Derivative Financial Instruments and Note 12 — 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 qualified pension funding decisions, including actuarially-determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act, and management of the pension obligation. The Pension Protection Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively) and at-risk status (which triggers higher minimum contribution requirements and participant notification). The contributions below reflect a funding strategy to make annual contributions to offset the growth of the liability. Based on this funding strategy and current market conditions, which are both subject to change, our annual qualified pension contribution was made in February 2025 for $161 million. Unlike the qualified pension plans, our non-qualified plans are not subject to statutory minimum contribution requirements.

OPEB plans are also not subject to statutory minimum contribution requirements, though we have funded a portion of our plans. Annually, we evaluate whether additional funding for those plans is needed. For our funded OPEB plans, we consider several factors in determining the level of our contributions, including liabilities management and levels of benefit claims paid. The estimated benefit payments to the non-qualified pension plans in 2025 are approximately $19 million and the planned contributions to the OPEB plans, including estimated benefit payments to unfunded plans, are $22 million. Expected contributions in 2025 or future years could be affected by adjustments in our pension and OPEB funding strategy, market conditions, or pension regulation changes. Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2024 Form 10-K for additional information on pension and other postretirement benefits.

Cash Requirements for Other Financial Commitments

Refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Liquidity and Capital Resources of our 2024 Form 10-K for additional information on our cash requirements for financial commitments.

Customer Accounts Receivable Financing

We have an accounts receivable financing facility with a number of financial institutions which provides us access to revolving loans secured by certain receivables. See Note 12 — Debt and Credit Agreements 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 16 — Debt and Credit Agreements of our 2024 Form 10-K for additional information on project finance credit facilities and nonrecourse debt.

Credit Facilities

We meet our short-term liquidity requirements primarily through the issuance of commercial paper. We may use our credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit. See Note 12 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on our credit facilities.

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 for radiological decommissioning of 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 regarding the latest funding status report filed with the NRC.

As of September 30, 2025, the Crane NDT is fully funded under the SAFSTOR scenario that was the planned decommissioning option, as described in the Crane PSDAR filed with the NRC in April 2019. We will continue to file Crane's decommissioning funding status with the NRC annually until restart, at which point we will file decommissioning funding status reports in accordance with applicable NRC requirements. Additionally, as of September 30, 2025, we have adequate NDT funds for the remaining radiological decommissioning costs at Zion Station related to the Independent Spent Fuel Storage Installation. Decommissioning costs other than radiological may require funding from us. See Liquidity and Capital Resources — NRC Minimum Funding Requirements of our 2024 Form 10-K for information regarding the risk of additional financial assurance for shutdown units.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

(Dollars in millions, unless otherwise noted)

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. We report risk management issues to the Executive Committee 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 2024 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 produce or procure differs from the amount of energy we have contracted to sell, we are exposed to market fluctuations in commodity prices. We seek to mitigate our commodity price risk through the sale and purchase of electricity, natural gas and oil, and other commodities.

Electricity available from our owned or contracted generation supply in excess of our obligations to customers is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, we enter into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures in locations and periods where our load serving activities do not naturally offset existing generation portfolio risk. Portfolio hedging activities are generally concentrated in the prompt three years, when customer demand and market liquidity enable effective price risk mitigation. We expect the settlement of the majority of our economic hedges will occur during 2025 through 2027. We also enter transactions that further optimize the economic benefits of our overall portfolio.

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. Beginning in 2024, our existing nuclear fleet is eligible for a nuclear PTC, an important tool in managing commodity price risk for each nuclear unit not already receiving state support. The nuclear PTC provides increasing levels of support as unit revenues decline below levels established in the IRA and is further adjusted for inflation annually through the duration of the program based on the GDP price deflator for the preceding calendar year. See Note 6 — Government Assistance of the Combined Notes to Consolidated Financial Statements for additional information.

The forecasted market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure as of September 30, 2025 for our portfolio associated with a $5/MWh reduction in the annual average around-the-clock energy price results in an impact to earnings that is not material for 2025 and a decrease to earnings of approximately $219 million for 2026. See Note 11 — 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 is obtained predominantly through long-term contracts for uranium concentrates, conversion services, enrichment services, (or a combination thereof) and fabrication services, including contracts sourced from Russia. 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 secure the nuclear fuel needed to continue to operate our nuclear fleet long-term. Approximately 35% of our uranium concentrate requirements for the remainder of 2025 through 2030 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 concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Geopolitical developments, including the Russia and Ukraine conflict and United States, United Kingdom, European Union, and Canadian sanctions against Russia, have the potential to impact delivery from multiple suppliers in the international uranium processing industry. Non-performance by these counterparties could have a material adverse impact on our consolidated financial statements. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Other Key Business Drivers for more information on the Russia and Ukraine conflict.

Trading and Non-Trading Marketing Activities

The following table provides detail on changes in our commodity derivative contract net assets (liabilities) balance sheet position from December 31, 2024 to September 30, 2025. This table incorporates the unrealized gains and losses that are immediately recorded in earnings. This table excludes all NPNS contracts. See Note 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the commodity derivative contract net assets (liabilities) recorded as of September 30, 2025 and December 31, 2024.

Balance as of December 31, 2024[a]	$ 317
Total change in fair value of contracts recorded in results of operations	(317)
Reclassification to realized at settlement of contracts recorded in results of operations	30
Changes in allocated collateral	190
Net option premium paid (received)	(49)
Option premium amortization	34
Upfront payments and amortizations[b]	(22)
Foreign currency translation	(1)
Balance as of September 30, 2025[a]	$ 182

(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 commodity derivative contract net assets (liabilities). See Note 13 — 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						
	2025	2026	2027	2028	2029	2030 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ (9)	$ 80	$ 32	$ (11)	$ (8)	$ (1)	$ 83
Prices provided by external sources (Level 2)	(39)	111	68	7	7	—	154
Prices based on model or other valuation methods (Level 3)	186	(85)	(111)	(31)	(22)	8	(55)
Total	$ 138	$ 106	$ (11)	$ (35)	$ (23)	$ 7	$ 182

(a) Represents unrealized gains and losses on commodity derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $776 million at September 30, 2025.

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 11 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk.

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 capacity, electricity, fuels, emissions allowances, and other energy-related products. 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 11 — Derivative Financial Instruments and Note 14 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

We sell output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on our consolidated financial statements. As market prices rise above or fall below contracted price levels, we are required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with us. To post collateral, we depend on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources — Credit Matters and Cash Requirements — Credit Facilities for additional information.

RTOs and ISOs

We participate in all of the established wholesale energy markets that are administered by PJM, ISO-NE, NYISO, CAISO, MISO, SPP, AESO, and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs and ISOs in markets regulated by FERC. In these areas, power and related products are traded through bilateral agreements between buyers and sellers and in the energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no RTO or ISO to administer energy markets, electricity and related products are purchased and sold solely through bilateral agreements. For activities administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member be shared by the remaining participants. Non-performance or non-payment by a major member of an RTO or ISO could result in a material adverse impact on our consolidated financial statements.

Exchange Traded Transactions

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

Interest Rate and Foreign Exchange Risk

We use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. We may also utilize interest rate swaps to manage our interest rate exposure, including derivatives to lock in rate levels in anticipation of future financings. A hypothetical 50 basis points change in interest rates associated with unhedged variable-rate long term debt and interest rate swaps would not have resulted in a material impact to our earnings for the nine months ended September 30, 2025. 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 11 — 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 have resulted in a $1,061 million reduction in the fair value of our NDT trust assets as of September 30, 2025. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Note 8 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements and Liquidity and Capital Resources section of ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information.

Our employee benefit plan trusts also hold investments in equity and debt securities. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates of our 2024 Form 10-K for further information.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

During the third quarter of 2025, our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in periodic reports that we file or submit with the SEC. These disclosure controls and procedures have been designed to ensure that (a) information relating to our consolidated subsidiaries, is accumulated and made known to our management, including our principal executive officer and principal financial officer, by other employees as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

As of September 30, 2025, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Changes in Internal Control Over Financial Reporting

We continually strive to improve our disclosure controls and procedures to enhance the quality of our financial reporting and to maintain dynamic systems that change as conditions warrant. There have been no changes in internal control over financial reporting that occurred during the third quarter of 2025 that have materially affected, or are reasonably likely to materially affect, any of our internal control 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 14 — 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, 2025, our risk factors were consistent with the risk factors described in our 2024 Form 10-K in ITEM 1A. RISK FACTORS.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities (CEG Parent)

Since 2023, our Board of Directors authorized the repurchase of up to $3 billion of the Company's outstanding common stock. No other repurchase plans or programs have been authorized. In February 2025, we entered into structured repurchase agreements whereby we purchased capped call options to reduce the total cost of our ongoing share repurchase program. Both agreements expired unexercised as of September 30, 2025. See Note 15 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information regarding our share repurchase program.

There were no open market share repurchases under the program during the nine months ended September 30, 2025.

In June 2025, we entered into an ASR agreement with a financial institution to initiate share repurchases of our common stock for $404 million, inclusive of taxes and other transaction costs. Under the ASR agreement, we received an initial share delivery of approximately 1.1 million shares of our common stock, which resulted in an immediate reduction in the number of our shares outstanding. In the third quarter of 2025, the remaining shares were delivered upon completion of the transaction and were based on the average of the daily-volume weighted average price of our common stock during the term, less a discount.

The following table provides information regarding our share repurchases under the program during the three months ended September 30, 2025:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid per Share	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Programs[(d)]
July 1, 2025 to July 31, 2025	—	$ —	$ 540
August 1, 2025 to August 31, 2025[(b)(c)]	183,135	311.84	593
September 1, 2025 to September 30, 2025	—	—	593
Total	183,135		$ 593

(a) We have not made any purchases of shares other than in connection with the publicly announced share repurchase program described above.
(b) Increase in remaining authority as a result of receipt of cash including a nominal cash premium following expiration of capped call option. See Note 15 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Represents the additional shares delivered under the June 2025 ASR agreement, which was fully settled in the third quarter of 2025.
(d) Approximate dollar value of shares that may yet be purchased under the program includes taxes and commissions.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

ITEM 5. OTHER INFORMATION

Rule 10b5-1 Trading Plans

During the three months ended September 30, 2025, none of our directors or executive officers (as defined in Rule 16a-1 under the Exchange Act) adopted or terminated any contract, instruction or written plan for the purchase or sale of our securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement" (as defined in Item 408 under Regulation S-K of the Exchange Act).

ITEM 6. EXHIBITS

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Exchange Act.

Exhibit No.	Description
10.1	Second Amended and Restated Credit Agreement dated as of September 19, 2025 among Constellation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the various financial institutions party thereto (File No. 333-85496, Form 8-K dated September 22, 2025, Exhibit 1.1)

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2025 filed by the following officers for the following registrants:

Exhibit No.	Description
31.1	Filed by Joseph Dominguez for Constellation Energy Corporation
31.2	Filed by Daniel L. Eggers for Constellation Energy Corporation
31.3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
31.4	Filed by Daniel L. Eggers for Constellation Energy Generation, LLC

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2025 filed by the following officers for the following registrants:

Exhibit No.	Description
32.1	Filed by Joseph Dominguez for Constellation Energy Corporation
32.2	Filed by Daniel L. Eggers for Constellation Energy Corporation
32.3	Filed by Joseph Dominguez for Constellation Energy Generation, LLC
32.4	Filed by Daniel L. Eggers for Constellation Energy Generation, LLC

Exhibit No.	Description
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)

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 7, 2025

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	Daniel L. Eggers
President and Chief Executive Officer (Principal Executive Officer)	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 7, 2025