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

FORM 10-K

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

For the Fiscal Year Ended December 31, 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
001-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street Chicago, Illinois 60603-2300 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) 2301 Market Street P.O. Box 8699 Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
001-01910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068-0001 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068-0001 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702-5440 (202) 872-2000	21-0398280

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

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

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

Title of Each Class

COMMONWEALTH EDISON COMPANY:

Common Stock Purchase Warrants (1971 Warrants and Series B Warrants)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☒	No ☐
Baltimore Gas and Electric Company	Yes ☒	No ☐
Pepco Holdings LLC	Yes ☐	No ☒
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒
Baltimore Gas and Electric Company	Yes ☐	No ☒
Pepco Holdings LLC	Yes ☐	No ☒
Potomac Electric Power Company	Yes ☐	No ☒
Delmarva Power & Light Company	Yes ☐	No ☒
Atlantic City Electric Company	Yes ☐	No ☒

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Exelon Corporation	Large Accelerated Filer ☒	Accelerated Filer ☐	Non-accelerated Filer ☐	Smaller Reporting Company ☐	Emerging Growth Company ☐
Commonwealth Edison Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
PECO Energy Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
Baltimore Gas and Electric Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
Pepco Holdings LLC	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
Potomac Electric Power Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
Delmarva Power & Light Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐
Atlantic City Electric Company	Large Accelerated Filer ☐	Accelerated Filer ☐	Non-accelerated Filer ☒	Smaller Reporting Company ☐	Emerging Growth Company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act by the registered public accounting firm that prepared or issued its audit report. ☒

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

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

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

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2025 was as follows:

Exelon Corporation Common Stock, without par value	$43,835,664,870
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company	None
Delmarva Power & Light Company	None
Atlantic City Electric Company	None

The number of shares outstanding of each registrant’s Common stock as of January 31, 2026 was as follows:

Exelon Corporation Common Stock, without par value	1,022,892,585
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,422
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company Common Stock, $0.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2026 Annual Meeting of Shareholders and the Commonwealth Edison Company 2026 Information Statement are incorporated by reference in Part III.

PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
Registrants	Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
Legacy PHI	PHI, Pepco, DPL, ACE, PES, and PCI, collectively
BSC	Exelon Business Services Company, LLC
EEDC	Exelon Energy Delivery Company, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
Exelon Enterprises	Exelon Enterprises Company, LLC
Exelon InQB8R	Exelon InQB8R, LLC
PCI	Potomac Capital Investment Corporation and its subsidiaries
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
UII	Unicom Investments, Inc.

Former Related Entities

Constellation	Constellation Energy Corporation and Constellation Energy Generation, LLC (formerly Exelon Generation Company, LLC, a subsidiary of Exelon as of December 31, 2021 prior to separation on February 1, 2022)

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

ABO	Accumulated Benefit Obligation
AECs	Alternative Energy Credits that are issued for each megawatt hour of generation from a qualified alternative energy source
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ATM	At the market
ARP	Alternative Revenue Program
BGS	Basic Generation Service
BSA	Bill Stabilization Adjustment
CBAs	Collective Bargaining Agreements
CEJA	Climate and Equitable Jobs Act; Illinois Public Act 102-0662 signed into law on September 15, 2021
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CIP	Conservation Incentive Program
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Convertible Senior Notes	Exelon's 3.25% Convertible Senior Notes due 2029
CMC	Carbon Mitigation Credit
CODMs	Chief Operating Decision Makers
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE during the Predecessor periods
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	District of Columbia Public Service Commission
DEPSC	Delaware Public Service Commission
DERs	Distributed Energy Resources
DOEE	Department of Energy & Environment
DPA	Deferred Prosecution Agreement
DPP	Deferred Purchase Price
DSIC	Distribution System Improvement Charge
EDIT	Excess Deferred Income Taxes
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ETAC	Energy Transition Assistance Charge
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
GWhs	Gigawatt hours
ICC	Illinois Commerce Commission
IIJA	Infrastructure Investment and Jobs Act

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

IIP	Infrastructure Investment Program
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRA	Inflation Reduction Act
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISOs	Independent System Operators
LNG	Liquefied Natural Gas
LTIP	Long-Term Incentive Plan
LTRRPP	Long-Term Renewable Resources Procurement Plan
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
mmcf	Million Cubic Feet
MRP	Multi-Year Rate Plan
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
N/A	Not Applicable
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOLC	Tax Net Operating Loss Carryforward
NPDES	National Pollutant Discharge Elimination System
NPNS	Normal Purchase Normal Sale scope exception
NPS	National Park Service
NRD	Natural Resources Damages
OCI	Other Comprehensive Income
OPEB	Other Postretirement Employee Benefits
PAPUC	Pennsylvania Public Utility Commission
PCBs	Polychlorinated Biphenyls
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
PJM Tariff	PJM Open Access Transmission Tariff
PLR	Private Letter Ruling
POLR	Provider of Last Resort
PPA	Purchase Power Agreement
PP&E	Property, Plant, and Equipment
PRPs	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to regulatory agreements with the ICC and PAPUC
RES	Retail Electric Suppliers
RFP	Request for Proposal

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
ROE	Return on Equity
ROU	Right-of-use
RPS	Renewable Energy Portfolio Standards
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SOA	Society of Actuaries
SOFR	Secured Overnight Financing Rate
SOS	Standard Offer Service
SSA	Social Security Administration
TCJA	Tax Cuts and Jobs Act
Transition Bonds	Transition Bonds issued by Atlantic City Electric Transition Funding LLC
USAO	United States Attorney's Office for the Northern District of Illinois
ZEC	Zero Emission Credit

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION

This Report contains certain forward-looking statements within the meaning of federal securities laws that are subject to risks and uncertainties. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” "should," 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. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the following important factors that may cause our actual results or outcomes to differ materially from those contained in our forward-looking statements, including, but not limited to:

- unfavorable legislative and/or regulatory actions;
- uncertainty as to outcomes and timing of regulatory approval proceedings and/or negotiated settlements thereof;
- environmental liabilities and remediation costs;
- state and federal legislation requiring use of low-emission, renewable, and/or alternate fuel sources and/or mandating implementation of energy conservation programs requiring implementation of new technologies;
- challenges to tax positions taken, tax law changes, and difficulty in quantifying potential tax effects of business decisions;
- negative outcomes in legal proceedings;
- physical security and cybersecurity risks;
- extreme weather events, natural disasters, operational accidents such as wildfires or natural gas explosions, war, acts and threats of terrorism, public health crises, epidemics, pandemics, or other significant events;
- disruptions or cost increases in the supply chain, including shortages in labor, materials or parts, or significant increases in relevant tariffs;
- lack of sufficient power generation resources to meet actual or forecasted demand or disruptions at generation facilities owned by third parties;
- emerging technologies that could affect or transform the energy industry;
- instability in capital and credit markets;
- a downgrade of any Registrant’s credit ratings or other failure to satisfy the credit standards in the Registrants’ agreements or regulatory financial requirements;
- significant economic downturns or increases in customer rates;
- impacts of climate change and weather on energy usage and maintenance and capital costs; and
- impairment of long-lived assets, goodwill, and other assets.

New factors emerge from time to time, and it is impossible for us to predict all of such factors, nor can we assess the impact of each such factor on the business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. For more information, see those factors discussed with respect to the Registrants in PART I, ITEM 1A. RISK FACTORS, and in other reports filed by the Registrants from time to time with the SEC. This Annual Report on Form 10-K also describes material contingencies and critical accounting policies in (a) PART II, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS and (b) PART II, ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA: Note 16, Commitments and Contingencies.

Investors are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

PART I

ITEM 1.

General

Corporate Structure and Business and Other Information

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through its subsidiaries, ComEd, PECO, BGE, Pepco, DPL, and ACE.

Name of Registrant	Business	Service Territories
Commonwealth Edison Company	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments: Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia and Major portions of Montgomery and Prince George's Counties, Maryland
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

Business Services

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, finance, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, finance, engineering, customer operations, transmission and distribution planning, asset management, system operations, and power procurement, to PHI operating Registrants. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Utility Registrants

Utility Operations

Service Territories and Franchise Agreements

The following table presents the size of service territories, populations of each service territory, and the number of customers within each service territory for the Utility Registrants as of December 31, 2025:

	ComEd	PECO	BGE	Pepco	DPL	ACE
Service Territories (in square miles)						
Electric	11,450	1,900	2,550	650	5,400	2,700
Natural Gas	N/A	1,900	3,050	N/A	250	N/A
Total[(a)]	11,450	2,100	3,250	650	5,400	2,700
Service Territory Population (in millions)						
Electric	9.5	4.2	3.0	2.5	1.5	1.2
Natural Gas	N/A	2.6	2.9	N/A	0.6	N/A
Total[(b)]	9.5	4.2	3.2	2.5	1.5	1.2
Main City	Chicago	Philadelphia	Baltimore	District of Columbia	Wilmington	Atlantic City
Main City Population	2.7	1.6	0.6	0.7	0.1	0.1
Number of Customers (in millions)						
Electric	4.2	1.7	1.4	1	0.6	0.6
Natural Gas	N/A	0.6	0.7	N/A	0.1	N/A
Total[(c)]	4.2	1.7	1.4	1	0.6	0.6

(a) The number of total service territory square miles counts once only a square mile that includes both electric and natural gas services, and thus does not represent the combined total square mileage of electric and natural gas service territories.
(b) The total service territory population counts once only an individual who lives in a region that includes both electric and natural gas services, and thus does not represent the combined total population of electric and natural gas service territories.
(c) The number of total customers counts once only a customer who is both an electric and a natural gas customer, and thus does not represent the combined total of electric customers and natural gas customers.

The Utility Registrants have the necessary authorizations to perform their current business of providing regulated electric and natural gas distribution services in the various municipalities and territories in which they now supply such services. These authorizations include charters, franchises, permits, and certificates of public convenience issued by local and state governments and state utility commissions. ComEd's, BGE's (gas), Pepco DC's, and ACE's rights are generally non-exclusive while PECO's, BGE's (electric), Pepco Maryland's, and DPL's rights are generally exclusive. Certain authorizations are perpetual while others have varying expiration dates. The Utility Registrants anticipate working with the appropriate governmental bodies to extend or replace the authorizations prior to their expirations. The current ComEd Franchise Agreement with the City of Chicago (the City) has been in effect since 1992. The Franchise Agreement became terminable on one year notice as of December 31, 2020. It now continues in effect indefinitely unless and until either party issues a notice of termination, effective one year later, or it is replaced by mutual agreement with a new franchise agreement between ComEd and the City. If either party terminates and no new agreement is reached between the parties, the parties could continue with ComEd providing electric services within the City with no franchise agreement in place. The City also has an option to terminate and purchase the ComEd system (municipalize), which also requires one year notice. Neither party has issued a notice of termination at this time, the City has not exercised its municipalization option, and no new agreement has become effective.

While Exelon and ComEd cannot predict the ultimate outcome, fundamental changes in the agreement or other adverse actions affecting ComEd’s business in the City would require changes in their business planning models and operations and could have a material adverse impact on Exelon’s and ComEd’s consolidated financial statements. If the City were to disconnect from the ComEd system, ComEd would seek full compensation for the business and its associated property taken by the City, as well as for all damages resulting to ComEd and its system. ComEd would also seek appropriate compensation for stranded costs with FERC.

Utility Regulations

State utility commissions regulate the Utility Registrants' electric and gas distribution rates and service, issuances of certain securities, and certain other aspects of the business. The following table outlines the state commissions responsible for utility oversight:

Registrant	Commission
ComEd	ICC
PECO	PAPUC
BGE	MDPSC
Pepco	DCPSC/MDPSC
DPL	DEPSC/MDPSC
ACE	NJBPU

The Utility Registrants are public utilities under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of the utilities' business. The U.S. Department of Transportation also regulates pipeline safety and other areas of gas operations for PECO, BGE, and DPL. The U.S. Department of Homeland Security (Transportation Security Administration) provided new security directives in 2021 that regulate cyber risks for certain gas distribution operators. Additionally, the Utility Registrants are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Seasonality Impacts on Delivery Volumes

The Utility Registrants' electric distribution volumes are generally higher during the summer and winter months when temperature extremes create demand for either summer cooling or winter heating. For PECO, BGE, and DPL, natural gas distribution volumes are generally higher during the winter months when cold temperatures create demand for winter heating.

ComEd, BGE, Pepco, DPL Maryland, and ACE have electric distribution decoupling mechanisms and BGE has a natural gas decoupling mechanism that eliminates the favorable and unfavorable impacts of weather and customer usage patterns on electric distribution and natural gas delivery volumes. As a result, ComEd's, BGE's, Pepco's, DPL Maryland's, and ACE's electric distribution revenues and BGE's natural gas distribution revenues are not intended to be impacted by delivery volumes. PECO's and DPL Delaware's electric distribution revenues and natural gas distribution revenues are impacted by delivery volumes.

Electric and Natural Gas Distribution Services

The Utility Registrants are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. Beginning in 2024 through 2027, ComEd's electric distribution costs are recovered in accordance with a multi-year rate plan approved by the ICC and through annual reconciliation proceedings litigated before the ICC. PECO's and DPL's electric and gas distribution costs and ACE’s electric distribution costs have generally been recovered through base rate case proceedings, with PECO utilizing a fully projected future test year, DPL Delaware's electric and gas distribution services utilizing either a partial actual and partial forecast test year or a fully historical test year, and ACE utilizing a fully historical test year. BGE’s electric and gas distribution costs and Pepco’s and DPL Maryland's electric distribution costs are currently recovered through multi-year rate case proceedings, as the MDPSC and the DCPSC allow utilities to file multi-year rate plans. In October 2025, Pepco Maryland filed a fully forecasted test year rate case while it awaits the conclusion of the lessons learned process. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

ComEd, Pepco, DPL and ACE customers have the choice to purchase electricity, and PECO and BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. DPL customers, with the exception of certain commercial and industrial customers, do not have the choice to purchase natural gas from competitive natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO, BGE, and DPL also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier.

For customers that choose to purchase electric generation or natural gas from competitive suppliers, the Utility Registrants act as the billing agent and therefore do not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from a Utility Registrant, the Utility Registrants are permitted to recover the electricity and natural gas procurement costs from customers without mark-up or with a slight mark-up and therefore record the amounts in Operating revenues and Purchased power and fuel expense. As a result, fluctuations in electricity or natural gas sales and procurement costs have no significant impact on the Utility Registrants’ Net income.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Results of Operations and Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding electric and natural gas distribution services.

Procurement of Electricity and Natural Gas

Exelon does not generate the electricity it delivers. The Utility Registrants' electric supply for its customers is primarily procured through contracts as directed by their respective state laws and regulatory commission actions. The Utility Registrants procure electricity supply from various approved bidders or from purchases on the PJM operated markets.

PECO's, BGE’s, and DPL's natural gas supplies are purchased from a number of suppliers for terms that currently do not exceed three years. PECO, BGE, and DPL each have annual firm transportation contracts of 437,000 mmcf, 258,000 mmcf, and 44,000 mmcf, respectively, for delivery of gas. To supplement gas transportation and supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE, and DPL have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	LNG Facility	**Propane-Air Plant**	**Underground Storage Service Agreements(a)**
PECO	1,200	150	19,400
BGE	1,056	550	22,000
DPL	250	N/A	3,900

(a) Natural gas from underground storage represents approximately 27%, 44%, and 33% of PECO's, BGE’s, and DPL's 2025-2026 heating season pipeline capacity, respectively.

PECO, BGE, and DPL have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO, BGE, and DPL make these sales as part of a program to balance its supply and cost of natural gas. The off-system gas sales are not material to PECO, BGE, and DPL.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK, Commodity Price Risk (All Registrants), for additional information regarding Utility Registrants' contracts to procure electric supply and natural gas.

Energy Efficiency Programs

The Utility Registrants are generally allowed to recover costs associated with energy efficiency and demand response programs they offer. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

ComEd, with limited exceptions, earns a return on its energy efficiency costs through a regulatory asset. ACE earns a return on most of its energy efficiency and demand response program costs through a regulatory asset. Historically, BGE, Pepco Maryland, and DPL Maryland deferred most of their energy efficiency program costs to a regulatory asset and either deferred most of their demand response program costs to a regulatory asset or capitalized them. In 2024, BGE, Pepco, and DPL began deferring less energy efficiency and demand response program costs to a regulatory asset as a result of the EmPOWER Maryland Cost Recovery program Beginning January 1, 2026, program costs are no longer being deferred. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Capital Investment

The Utility Registrants' businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability, and efficiency of their systems. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources, for additional information regarding projected 2026 capital expenditures.

Transmission Services

The Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities at cost-based rates pursuant to tariffs approved by FERC. The Utility Registrants and their affiliates are required to comply with FERC’s Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owner’s employees and wholesale merchant employees.

PJM is the regional grid operator and operates pursuant to its FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Tariff. PJM operates the PJM energy, capacity, and other wholesale markets. PJM controls the day-to-day operations of the bulk power system for the region. The Utility Registrants are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of certain of their transmission facilities to PJM, and their transmission systems are under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis through the transmission facilities of the PJM transmission owners.

The Utility Registrants' transmission rates are based on a FERC approved formula. The rates are updated on an annual basis.

Exelon’s Strategy and Outlook

Exelon is a transmission and distribution company that delivers electricity and natural gas service to our customers and communities. Exelon's businesses remain focused on maintaining industry leading operational excellence, meeting or exceeding their financial commitments, ensuring timely recovery on investments to enable customer benefits, supporting clean energy policies including those that advance our jurisdictions' clean energy targets, and continued commitment to corporate responsibility.

Exelon’s strategy is to improve reliability and operations, enhance the customer experience, and advance clean and affordable energy choices, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The jurisdictions in which Exelon has operations have set some of the nation's leading clean energy targets and our strategy is to enable that future for all our stakeholders. The Utility Registrants invest in rate base that supports service to our customers and the community, including investments that sustain and improve affordability, reliability, resiliency, security and safety to enhance the service experience of our customers. The Utility Registrants make these investments prudently at a reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results.

Management continually evaluates growth opportunities aligned with Exelon’s businesses, assets, and markets, leveraging Exelon’s expertise in those areas and offering sustainable returns.

The Utility Registrants anticipate investing approximately $41 billion over the next four years in electric and natural gas infrastructure improvements and modernization projects, including smart grid technology, storm hardening, advanced reliability technologies, new business including data centers, and transmission projects, which is projected to result in an increase to current rate base of approximately $23 billion by the end of 2029. These investments provide greater reliability, improved service for our customers, increased capacity to accommodate new technologies and support a cleaner grid, and a stable return for the company.

In August 2021, Exelon announced its Path to Clean goal to collectively reduce its operations-driven GHG emissions 50% by 2030 against a 2015 baseline and to reach net-zero operations-driven GHG emissions by 2050, while supporting customers and communities in achieving their GHG reduction goals (Path to Clean). Exelon's quantitative goals include its Scope 1 and 2 GHG emissions, with the exception of Scope 2 emissions associated with system losses of electric power delivered to customers (line losses), and build upon Exelon's long-standing commitment to reducing our GHG emissions. Exelon's Path to Clean efforts extend beyond these quantitative goals to include efforts such as customer energy efficiency programs, which support reductions in customers' direct emissions and have the potential to reduce Exelon's Scope 3 emissions and Scope 2 line losses as well. See ITEM 1. BUSINESS — Environmental Matters and Regulation — Climate Change for additional information.

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

Employees

Human Capital Management

Exelon’s workforce is critical to advancing energy transformation and achieving sustainable, long-term growth. As the Company competes for critical capabilities in the marketplace, Exelon must attract, develop, and equip its workforce to meet evolving business and industry needs. Accordingly, Exelon’s human capital management strategy is centered on maintaining and enhancing its reputation as an employer of choice within the energy and utility industry.

Exelon seeks to attract and retain talent by fostering a safe, inclusive, and engaging workplace that offers meaningful work, clearly defined roles, opportunities for professional development, supportive leadership, work-life balance, and competitive benefits that support employee well-being across all stages of life.

Exelon’s talent strategy supports the attraction, development, engagement, and advancement of employees across all businesses and functions. The Company deploys a comprehensive recruiting approach to address current and future workforce needs, including workforce development initiatives, annual internship and cooperative education programs, targeted recruiting for specialized and hard-to-fill roles, and partnerships with colleges, universities, trade schools, and community organizations.

Exelon invests in employee development through leadership development programs, technical training, and mentoring. Talent growth and internal mobility are supported through performance development, talent review, and succession planning processes. Employees are encouraged to complete annual individual development plans to identify skill-building opportunities, supported by managers and Exelon’s development offerings.

Exelon’s total rewards programs support its talent strategy by attracting, retaining, and motivating high-performing employees while reinforcing the Company’s pay-for-performance philosophy and supporting employee well-being. Compensation is designed to be market-competitive and is informed by benchmarking many positions using external survey data. All employees participate in an annual incentive program that aligns individual performance with business results and supports a high-performance culture.

Exelon promotes transparency in compensation and performance-based rewards by providing education, tools, and resources that help leaders and employees understand the Company's market-based pay approach and the connection between performance, ratings, and compensation outcomes.

In addition, Exelon offers a comprehensive portfolio of benefit programs that support employees' emotional, physical, and financial well-being, enabling employees to perform effectively and supporting overall organizational effectiveness.

The following table shows the total number of employees at each Registrant as of December 31, 2025.

Employees	Exelon[(a)]	ComEd	PECO	BGE	PHI[(b)]	Pepco	DPL	ACE
Total Employees	20,571	6,688	3,169	3,383	4,422	1,374	945	630

(a) Exelon includes individuals employed by BSC in addition to those employed by ComEd, PECO, BGE, and PHI. Exelon Corporate does not employ any individuals.
(b) PHI includes individuals employed by PHISCO in addition to those employed by Pepco, DPL, and ACE.

Approximately 42% of Exelon's employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2025.

	Total Employees Covered by CBAs	Number of CBAs	CBAs New and Renewed in 2025[(a)]	Total Employees Under CBAs New and Renewed in 2025
Exelon	8,656	10	2	941
ComEd	3,543	2	1	73
PECO	1,524	2	—	—
BGE	1,495	1	—	—
PHI	2,094	5	1	868
Pepco	861	1	1	861
DPL	650	2	—	—
ACE	397	2	—	—
Corporate[(b)]	186	—	—	7

(a) Does not include CBAs that were extended in 2025 while negotiations are ongoing for renewal.
(b) Corporate represents employees employed by BSC or PHISCO.

The table below shows the average turnover rate for all employees for 2023 to 2025.

Employees	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Retirement Age	2.39 %	2.72 %	2.54 %	2.06 %	2.17 %	2.00 %	2.40 %	2.10 %
Voluntary	2.58 %	2.40 %	2.06 %	1.82 %	2.78 %	2.82 %	1.29 %	2.58 %
Non-Voluntary	0.96 %	0.83 %	1.34 %	1.00 %	1.04 %	1.78 %	0.68 %	0.65 %

Environmental Matters and Regulation

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

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the President and Chief Executive Officer; the Senior Vice President and Chief Strategy and Sustainability Officer; as well as senior management of the Utility Registrants. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Audit and Risk Committee oversees compliance with environmental laws and regulations, including environmental risks related to Exelon's operations and facilities, as well as SEC disclosures related to environmental matters. Exelon's Corporate Governance Committee has the authority to oversee Exelon’s climate change and sustainability policies and programs, as discussed in further detail below. The respective Boards of the Utility Registrants oversee environmental issues related to these companies. The Exelon Board of Directors has general oversight responsibilities for Environmental, Social, and Governance matters, including strategies and efforts to protect and improve the quality of the environment.

Climate Change

As detailed below, the Registrants face climate change mitigation and transition risks as well as adaptation risks. Mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions. Adaptation risk refers to risks to the Registrants' facilities or operations that may result from changes to the physical climate and environment, such as changes to temperature, weather patterns and sea level.

Climate Change Mitigation and Transition

The Registrants support comprehensive federal climate legislation that addresses the urgent need to substantially reduce national GHG emissions while providing appropriate protections for consumers, businesses, and the economy. In the absence of comprehensive federal climate legislation, Exelon continues to support the EPA's authority to regulate GHG emissions under the Clean Air Act.

The Registrants currently are subject to, and may become subject to additional, federal and/or state law and/or regulations addressing GHG emissions. The direct (Scope 1) GHG emission sources associated with the Registrants include sulfur hexafluoride (SF6) leakage from electric transmission and distribution operations, fossil fuel combustion in motor vehicles and refrigerant leakage from chilling and cooling equipment. In addition, PECO, BGE, and DPL, as distributors of natural gas, have natural gas (methane) leakage on the natural gas systems. The Registrants also have indirect (Scope 2 and 3) emissions associated with the production of the electricity they consume and deliver, and indirect (Scope 3) emissions associated with the production of natural gas they deliver and consumer use of such natural gas.

Exelon uses definitions and protocols provided by the World Resources Institute for its GHG inventory. In 2024, new methods were introduced that resulted in changes to Exelon's verified GHG inventory. Exelon's final verified 2024 Scope 1 and 2 GHG emissions were just over 4.6 million metric tons carbon dioxide equivalent using the World Resources Institute Corporate Standard Market-based accounting. Of these emissions, 0.4 million metric tons are considered to be operations-driven and in more direct control of our employees and processes. The majority of these operations-driven emissions are fugitive emissions from the gas delivery systems of PECO, BGE, and DPL. The remaining 4.2 million metric tons, approximately 91%, are the indirect emissions associated with the electric transmission and distribution system and primarily consists of losses resulting from the Utility Registrant's delivery of electricity to their customers (line losses). These emissions are driven primarily by customer demand for electricity and the mix of generation assets supplying energy to the electric grid. The Registrants do not own generation and must comply with applicable legal and regulatory requirements governing procurement of electricity for delivery to retail customers and use of the system to support other transmission transactions. However, the Registrants do engage in efforts that help to reduce these emissions, including customer programs to drive customer energy efficiency, to help manage peak demands, and to enable distributed solar generation.

In August 2021, Exelon announced a Path to Clean goal to collectively reduce its operations-driven GHG emissions 50% by 2030 against a 2015 baseline, and to reach net-zero operations-driven GHG emissions by 2050, while also supporting customers and communities to achieve their clean energy and emissions reduction goals. Exelon’s quantitative goals include its Scope 1 and 2 GHG emissions with the exception of Scope 2 line losses, and build upon Exelon's long-standing commitment to reducing our GHG emissions. Exelon's activities in support of the Path to Clean goal will include efficiency and clean electricity for operations, vehicle fleet electrification, equipment and processes to reduce sulfur hexafluoride (SF6) leakage, investments in natural gas infrastructure to minimize methane leaks and increase safety and reliability, and investment and collaboration to develop new technologies. Beyond 2030, Exelon recognizes that technology advancement and continued policy support will be needed to ensure achievement of its net-zero goal by 2050. Exelon is laying the groundwork by partnering with national labs, universities, and research consortia to research, develop, and pilot clean technologies, as well as working with our states, jurisdictions, and policy makers to understand the scope and scale of energy transformation, and policies and incentives, needed to reach local ambitions for GHG emissions reductions. The Utility Registrants are also supporting customers and communities to achieve their clean energy and emissions goals through significant energy efficiency programs. Estimated customer program energy efficiency investments across the Utility Registrants for 2026 to 2029 total $4.9 billion. These programs enable customer savings through home energy audits, discounts on efficient lighting, appliance recycling, home improvement rebates, equipment upgrade incentives, and innovative programs like smart thermostats and combined heat and power programs.

As an energy delivery company, Exelon can play a role in helping to reduce GHG emissions in its service territories. In connecting end users of energy to electric and gas supply, Exelon can leverage its assets and customer interface to help support efficient use of lower emitting resources as they become available. Electrification, where feasible, for transportation, buildings, and industry coupled with simultaneous decarbonization of electric generation, can be an important means to reduce emissions. Exelon is advocating for public policy supportive of vehicle electrification, investing in enabling infrastructure and technology, and supporting customer education and adoption. In addition, the Utility Registrants have achieved their goal to electrify 30% of their vehicle fleet by 2025. Clean fuels and other emerging technologies can also support the transition, lessen the strain on electric system expansion, and support energy system resiliency. Exelon, PECO, BGE, and DPL, which own gas distribution assets, are also continuing to explore these other decarbonization opportunities, supporting pilots of emerging energy technologies and clean fuels to support both operational and customer-driven emissions reductions. Exelon believes its market and business model could be significantly affected by the transition of the energy system, such as through an increased electric load and decreased demand for natural gas, potentially accompanied by changes in technology, customer expectations, and/or regulatory structures. See the risk factor entitled "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" in ITEM 1A. of this report for additional information.

Climate Change Adaptation

The Registrants' facilities and operations are subject to the impacts of global climate change. Long-term shifts in climactic patterns, such as sustained higher temperatures and sea level rise, may present challenges for the Registrants and their service territories. Exelon believes its operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS for additional information related to the Registrants' risks associated with climate change.

The Registrants' assets undergo seasonal readiness efforts to ensure that they are prepared for the weather projections for the summer and winter months. The Registrants consider and review national climate assessments to inform their planning. Each of the Utility Registrants also has well established system recovery plans and is investing in its systems to install advanced equipment and reinforce the local electric system, making it more weather resistant and less vulnerable to anticipated storm damage.

International Climate Change Agreements. At the international level, the United States has been a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. In January 2025, the current administration issued a Presidential Executive Order instructing the federal government to begin the actions needed to withdraw from the Paris Agreement. This withdrawal process will take a year to complete. The United States elected not to participate in the COP meeting (COP 30) in 2025.

State Climate Change Legislation and Regulation. A number of states in which the Registrants operate have state and regional programs to reduce GHG emissions and renewable and other portfolio standards, which impact the power sector. See discussion below for additional information on renewable and other portfolio standards.

Certain northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont) currently participate in the RGGI. The program requires most fossil fuel-fired power plant owners and operators in the region to hold allowances, purchased at auction, for each ton of CO_2 emissions. Non-emitting resources do not have to purchase or hold these allowances.

Broader state programs impact other sectors as well, such as the District of Columbia's Clean Energy DC Omnibus Act and cross-sector GHG reduction plans, which resulted in recent requirements for Pepco to develop a 15-year decarbonization program and strategy. Maryland expects to meet and exceed the mandate set in the Greenhouse Gas Emissions Reduction Act to reduce statewide GHG emissions 40% (from 2006 levels) by 2030, and the state’s Climate Solutions Now Act of 2022 further updates requirements with a proposal to reduce emissions 60% (from 2006 levels) by 2031 and achieve net-zero emissions by 2045. New Jersey accelerated its goals through Executive Order 274, which establishes an interim goal of 50% reductions below 2006 levels by 2030 and affirms its goal of achieving 80% reductions by 2050 and includes programs to drive greater amounts of electrified transportation. Delaware's Climate Change Solutions Act, established in August 2023, sets a statewide GHG emissions reduction goal of 50% by Jan 1, 2030 and a net-zero GHG emissions goal by Jan 1, 2050, on a net basis as compared to a 2005 baseline. Illinois’ climate bill, CEJA, establishes decarbonization requirements for the state to transition to 100% clean energy by 2050 and supports programs to improve energy efficiency, manage energy demand, attract clean energy investment, and accelerate job creation. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on CEJA.

The Registrants cannot predict the nature of future regulations or how such regulations might impact future financial statements. See ITEM 1A. RISK FACTORS for additional information related to the Registrants' risks associated with climate legislation.

Renewable and Clean Energy Standards. Each of the states where Exelon operates have adopted some form of renewable or clean energy procurement requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. The Utility Registrants comply with these various requirements through acquiring sufficient bundled or unbundled credits such as RECs, CMCs, or ZECs, or paying an alternative compliance payment, and/or a combination of these compliance alternatives. The Utility Registrants are permitted to recover from retail customers the costs of complying with their state RPS requirements, including the procurement of RECs or other alternative energy resources. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other Environmental Regulation

Water Quality

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

Under Clean Water Act Section 404 and state laws and regulations, the Registrants may be required to obtain permits for projects involving dredge or fill activities in Waters of the United States. What constitutes a Water of the United States has been subject to varied definition over the past several administrations. The current administration has issued notice that the application of Waters of the United States will use a more narrow scope than has been applied historically.

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

Solid and Hazardous Waste and Environmental Remediation

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

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

ComEd's and PECO's environmental liabilities primarily arise from contamination at former MGP sites, which were operated by ComEd's and PECO's predecessor companies. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover certain environmental remediation costs of the MGP sites through a provision within customer rates. BGE, Pepco, DPL, and ACE do not have material contingent liabilities relating to MGP sites. The amount to be expended in 2026 for activities associated with the environmental investigation and remediation related to contamination at former MGP sites and other gas purification sites is estimated to be approximately $21 million, which consists primarily of $13 million at PECO.

As of December 31, 2025, the Registrants have established appropriate contingent liabilities for environmental remediation requirements. In addition, the Registrants may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Note 2 — Regulatory Matters and Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' environmental matters, remediation efforts, and related impacts to the Registrants' Consolidated Financial Statements.

Information about our Executive Officers as of February 12, 2026

Exelon

Name	Age	Position	Period
Butler Jr., Calvin G.	56	President and Chief Executive Officer, Exelon	2022 - Present
		Chief Operating Officer, Exelon	2021 - 2022
		Senior Executive Vice President, Exelon	2019 - 2022
		Chief Executive Officer, Exelon Utilities	2019 - 2022
Honorable, Colette	55	Executive Vice President, Chief Legal Officer, Compliance and Corporate Secretary, Exelon	2026 - Present
		Chief Legal Officer and Corporate Secretary	2024 - 2025
		Executive Vice President, Public Policy	2023 - 2024
		Chief External Affairs Officer	2023 - 2024
		Partner, Reed Smith LLP	2017 - 2023
Innocenzo, Michael A.	60	Executive Vice President and Chief Operating Officer, Exelon	2024 - Present
		President and Chief Executive Officer, PECO	2018 - 2024
Jones, Jeanne	46	Executive Vice President, Chief Finance Officer, Audit and Risk, Exelon	2026 - Present
		Executive Vice President and Chief Financial Officer, Exelon	2022 - 2025
		Senior Vice President, Corporate Finance, Exelon	2021 - 2022
		Senior Vice President and Chief Financial Officer, ComEd	2018 - 2021
Kleczynski, Robert A.	57	Senior Vice President, Controller and Tax, Exelon	2023 - Present
		Senior Vice President, Tax, Exelon	2020 - 2023
Peterson, Timothy	49	Executive Vice President, Chief Customer & Technology Officer, Exelon	2026 - Present
		Senior Vice President, Chief Technology Officer, Xcel Energy	2019-2026

ComEd

Name	Age	Position	Period
Quiniones, Gil	59	President, ComEd	2024 - Present
		Chief Executive Officer, ComEd	2021 - Present
		President and Chief Executive Officer, New York Power Authority	2011 - 2021
Levin, Joshua	46	Senior Vice President, Chief Financial Officer & Treasurer, ComEd	2023 - Present
		Vice President, Corporate Finance, Planning and Analysis	2021 - 2023
		Director of Financial Planning and Analysis, ComEd	2019-2021
Perez, David R.	56	Executive Vice President and Chief Operating Officer, ComEd	2024 - Present
		Senior Vice President, Distribution Operations, ComEd	2019 - 2023
Rippie, E. Glenn	65	Senior Vice President and General Counsel, ComEd	2022 - Present
		Senior Vice President and Deputy General Counsel, Energy Regulation, Exelon	2022 - Present
		Partner, Jenner & Block LLP	2019 - 2022
Washington, Melissa	56	Senior Vice President, Governmental, Regulatory and External Affairs, ComEd	2025 - Present
		Senior Vice President, Customer Operations, ComEd	2021 - 2025
		Senior Vice President, Governmental and External Affairs, ComEd	2019 - 2021

PECO

Name	Age	Position	Period
Vahos, David	53	President and Chief Executive Officer, PECO	2025 - Present
		Senior Vice President, Chief Financial Officer, and Treasurer, PHI	2024 - 2025
		Senior Vice President, Chief Financial Officer, and Treasurer, BGE	2016 - 2024
Gay, Anthony	60	Vice President and General Counsel, PECO	2019 - Present
Humphrey, Marissa	46	Senior Vice President, Chief Financial Officer and Treasurer, PECO	2022 - Present
		Vice President, Regulatory Policy and Strategy (NJ/DE), PHI, DPL, and ACE	2021 - 2022
Levine, Nicole	49	Senior Vice President and Chief Operations Officer, PECO	2022 - Present
		Vice President, Electrical Operations, PECO	2018 - 2022
Oliver, Douglas	51	Senior Vice President, Governmental, Regulatory and External Affairs, PECO	2023 - Present
		Vice President, Governmental and External Affairs, PECO	2019 - 2023

BGE

Name	Age	Position	Period
Olivier, Tamla	53	President and Chief Executive Officer, BGE	2025 - Present
		Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2021 - 2025
		Senior Vice President, Customer Operations, BGE	2020 - 2021
Cloyd, Michael	55	Senior Vice President, Chief Financial Officer, and Treasurer, BGE	2024 - Present
		Vice President, Support Services, BGE	2021 - 2024
Dickens, Derrick	61	Senior Vice President and Chief Operating Officer, BGE	2021 - Present
		Senior Vice President, Customer Operations, PHI, Pepco, DPL, and ACE	2020 - 2021
Ralph, David	59	Vice President and General Counsel, BGE	2021 - Present
		Associate General Counsel, BGE	2019 - 2021

PHI, Pepco, DPL, and ACE

Name	Age	Position	Period
Anthony, J. Tyler	61	President and Chief Executive Officer, PHI, Pepco, DPL, and ACE	2021 - Present
		Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2016 - 2021
Bancroft, Anne	59	Vice President and General Counsel, PHI, Pepco, DPL, and ACE	2021 - Present
		Associate General Counsel, Exelon	2017 - 2021
Oddoye, Rodney	49	Senior Vice President and Chief Operating Officer	2025 - Present
		Senior Vice President, Governmental, Regulatory and External Affairs, PHI, Pepco, DPL, and ACE	2021 - 2025
Cantler, Jaclyn	46	Senior Vice President, Governmental, Regulatory and External Affairs, PHI, DPL, and ACE	2025 - Present
		Vice President, Pepco Electric Operations, PHI, Pepco	2024 - 2025
		Vice President, Projects and Contracts, PHI, Pepco, DPL, and ACE	2021 - 2024
O'Donnell, Morgan	50	Senior Vice President, Chief Financial Officer, and Treasurer, PHI, Pepco, DPL, and ACE	2025 - Present
		Vice President, Regulatory Policy and Strategy, PHI, Pepco and DPL	2021 - 2025

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a complex market and regulatory environment that involves significant risks, many of which are beyond that Registrant’s direct control. A number of these risks, any of which could negatively affect one or more of the Registrants’ future Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, and/or Consolidated Balance Sheets (consolidated financial statements), are captured below. Although the risks are generally organized by category and separately described, many of these risks are interrelated. Additionally, the risks should be considered holistically with other information included in this filing and future filings with the SEC. There may be further risks and uncertainties that are presently known or that are not currently believed to be material that could negatively affect the Registrants' future consolidated financial statements.

Risks Related to Legislative, Regulatory, and Legal Factors

The Registrants' businesses are highly regulated and electric and gas revenue and earnings could be negatively affected by legislative and/or regulatory actions (All Registrants).

Substantial aspects of the Registrants' businesses are subject to comprehensive Federal or state legislation and/or regulation.

The Utility Registrants' consolidated financial statements are heavily dependent on the ability of the Utility Registrants to recover their costs associated with the retail purchase, transmission, and distribution of power and natural gas to their customers.

Fundamental changes in laws or regulations or adverse legislative or regulatory actions affecting the Registrants' businesses would require changes in their business planning models and operations. Registrants cannot always predict when or whether legislative or regulatory action will occur and may not be able to influence the outcome of legislative or regulatory initiatives.

Changes in the Utility Registrants' respective terms and conditions of service, including their respective rates, along with adoption of new rate structures and constructs, or establishment of new rate cases, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy, and subject to appeal, which leads to uncertainty as to the ultimate result, and which could result in uncertainties in rate case outcomes, and/or introduce time delays in effectuating rate changes (All Registrants).

The Utility Registrants are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services, adoption of new rate structures and constructs or establishment of new rate cases. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for a Utility Registrant to recover its costs once the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates including recovery mechanisms for costs associated with the procurement of electricity or gas, credit losses, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs, could be adjusted, subject to refund, or disallowed. In certain instances, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives, or franchise agreements. These settlements are subject to regulatory approval. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of the Utility Registrants to recover their costs or earn an adequate return.

In addition to potential timing delays, the Registrants also face other uncertainties in rate proceedings that could impact recovery, including not obtaining anticipated allowed rates of return, allowed capital structures, or allowed return on pension assets, and various other factors.

See Note 2 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of the Utility Registrants to the results of NERC compliance requirements (All Registrants).

The Utility Registrants as users, owners, and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC, MDPSC, DCPSC, DEPSC, and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Utility Registrants were found in non-compliance with the Federal or state mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters (All Registrants).

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

The Registrants could be negatively affected by federal and state RPS, energy conservation and GHG reduction legislation and regulation, and/or changing customer expectations, along with energy conservation by customers (All Registrants).

Risks include changes to energy systems due to new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state, or federal regulatory requirements intended to reduce GHG emissions and/or mandate implementation of energy conservation programs, including through limitation of the use of natural gas. Changes to current state legislation or the development of Federal legislation that requires the use of low-emission, renewable, and/or alternate fuel sources could significantly impact the Utility Registrants, especially if timely cost recovery is not allowed. In addition, where requirements and compliance mechanisms have previously been established, the withdrawal of such requirements can introduce costs and uncertainty.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart grid, DERs and energy efficiency programs, could increase capital expenditures and could significantly impact the Utility Registrants' consolidated financial statements if timely cost recovery is not allowed. These energy conservation programs, regulated energy consumption reduction targets, and new energy consumption technologies for PECO, could cause declines in customer energy consumption and lead to a decline in the Registrants' earnings, if timely recovery is not allowed.

The Registrants also periodically perform analyses of potential energy system transition pathways to reduce economy-wide GHG emissions to mitigate climate change. To the extent additional GHG reduction legislation and/or regulation becomes effective at the Federal and/or state levels, the Registrants could incur costs to further limit the GHG emissions from their operations or otherwise comply with applicable requirements and such legislation and/or regulation could otherwise adversely affect the Registrants' businesses. See ITEM 1. BUSINESS — Environmental Matters and Regulation — Renewable and Clean Energy Standards and "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" above for additional information.

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

The Registrants are required to make judgments to estimate their obligations to taxing authorities, which includes general tax positions taken and associated reserves established. Tax obligations include, but are not limited to: income, real estate, sales and use, and employment-related taxes and ongoing appeal issues related to these tax matters. All tax estimates could be subject to challenge by the tax authorities. Additionally, earnings may be impacted due to changes in federal or local/state tax laws, and the inherent difficulty of estimating potential tax effects of ongoing business decisions. See Note 1 — Significant Accounting Policies and Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Legal proceedings could result in a negative outcome, which the Registrants cannot predict (All Registrants).

The Registrants are involved in legal proceedings, claims, and litigation arising out of their business operations. The material legal proceedings, claims, and litigation arising out of business operations are summarized in Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue, or restrict or disrupt business activities.

The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences (All Registrants).

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

Risks Related to Operational Factors

The Utility Registrants' operating costs are affected by their ability to maintain the availability and reliability of their delivery and operational systems (All Registrants).

Failures of the equipment or facilities used in the Utility Registrants' delivery systems could interrupt electric transmission and/or electric or natural gas delivery, which could result in a loss of revenues and an increase in maintenance and capital expenditures. Equipment or facilities failures can occur due to several factors, including natural causes such as weather or information systems failure. Specifically, if the implementation of AMI, smart grid, or other technologies in the Utility Registrants' service territory fail to perform as intended or are not successfully integrated with billing and other information systems, or if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants' financial results could be negatively impacted. In addition, dependence upon automated systems could further increase the risk that operational system flaws or internal and/or external tampering or manipulation of those systems will result in losses that are difficult to detect.

Regulated utilities, which are required to provide service to all customers within their respective service territories, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, which could be material.

The Registrants are subject to physical security and cybersecurity risks (All Registrants).

Risks from cybersecurity and physical threats to energy infrastructures and personnel are increasing. Threat actors, including sophisticated nation-state actors and criminal groups, exploit potential vulnerabilities in the electric and natural gas utility industry, grid infrastructure, and other energy infrastructures. Attacks and disruptions, which could involve physical, cyber, and hybrid targeting of physical and cyber assets, are increasingly sophisticated and dynamic. Physical attacks targeting the Registrants' physical assets or personnel could cause injuries, damage, or operational disruptions. The increased implementation of, and reliance on, information technologies and networks to manage business operations, including the operation of technical systems, as well as the Registrants' use of numerous vendors and suppliers, create additional points of vulnerability that could be, and in certain instances have been, exploited by malicious threat actors. Several U.S. government agencies have warned that the energy sector and its supply chains are subject to increasing risks of physical attacks, ransomware attacks and cybersecurity threats, and that the risks may escalate during periods of heightened geopolitical tensions. In addition, the rapid evolution and increased adoption of artificial intelligence technologies may intensify the Registrants' cybersecurity risks.

A security breach of the Registrants' physical assets or information systems or those of the Registrants' competitors, vendors, business partners and interconnected entities (including RTOs and ISOs) could materially impact Registrants by, among other things, impairing the availability of electricity and gas distributed by Registrants and/or the reliability of transmission and distribution systems, damaging grid infrastructure, interrupting critical business functions, impairing the availability of vendor services and materials that the Registrants rely on to maintain their operations, or by leading to the theft or inappropriate release of certain types of information, including critical infrastructure information, system data and architecture, sensitive customer, vendor, or employee data, or other confidential data. While Registrants and some of the Registrants' vendors have experienced cybersecurity incidents, such incidents have not, to Registrants' knowledge, resulted in material impact to any of the Registrants to date.

If a material physical or cybersecurity breach or disruption were to occur, the Registrants' reputation could be negatively affected, customer confidence in the Registrants could be diminished and the Registrants could be subject to legal claims, regulatory exposure, loss of revenues, and increased costs, including infrastructure repairs or operations shutdown, all of which could materially affect the Registrants' financial condition and materially damage their business reputation. Moreover, the amount and scope of insurance maintained against losses resulting from any such security breaches or disruptions may not be sufficient to cover losses or otherwise adequately compensate for any resulting business disruptions. The continued increase in Federal and state regulatory requirements related to cybersecurity and evolving threat actor-capabilities could require changes to measures currently undertaken by the Registrants or to their business operations and could adversely affect their consolidated financial statements.

The Registrants’ electricity and natural gas operations are inherently hazardous and involve significant risks to employees, contractors, customers, and the general public (All Registrants).

Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near the Registrants’ operations. As a result, employees, contractors, customers, and the general public may face, and in the past have experienced, serious injury, including loss of life, damage to or destruction of facilities and residences, business interruptions, and environmental pollution. These risks include, among others, gas explosions, uncontrolled release of natural gas and other environmental hazards, fires, pole strikes, and electric contact cases. Further, the location of natural gas pipelines and associated distribution facilities, or electric generation, transmission, substations and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, increases the potential damages resulting from these risks.

Extreme weather events, natural disasters, operational accidents such as wildfires or natural gas explosions, war, acts and threats of terrorism or sabotage, cyberattacks or compromises, equipment or process failures, public health crises, or other significant events could negatively impact the Registrants' results of operations, ability to raise capital and future growth (All Registrants).

The Utility Registrants' infrastructures and/or operations could be affected by extreme weather events, natural disasters, operational accidents such as wildfires or natural gas explosions or equipment or process failures due to aging infrastructure or otherwise, each of which could result in increased costs, including supply chain costs and claims for third-party property damage. An extreme weather event, natural disaster, wildfire, or operational accident within the Utility Registrants’ service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment.

The Registrants face a risk that their operations would be direct targets or indirect casualties of attacks or sabotaged by nation-states or their agents, or by foreign or domestic terrorist groups. Responses to such attacks or sabotage, and any resulting retaliatory actions or sustained conflict could affect the Registrants’ operations and finances in unpredictable and material ways. Furthermore, such events could compromise the physical or cybersecurity of the Registrants' facilities, which could adversely affect the Registrants' ability to manage their businesses effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, public health crises, epidemics, pandemics, credit crises, recession, sustained high inflation, or other significant events also could result in a decline in energy consumption or interruption of fuel or the supply chain. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants could be significantly affected by public health crises, including epidemics or pandemics. The Registrants have plans in place to respond to such events. However, depending on the severity and the resulting impacts to workforce and other resource availability, a public health crisis, epidemic, or pandemic could adversely affect our vendors, or customers and customer demand as well as the Registrants' ability to operate their transmission and distribution assets.

In addition, Exelon, on behalf of the Registrants, maintains a level of insurance coverage consistent with industry practices against property, casualty, third party liability, and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, such losses may not be covered under applicable insurance policies, or the amount of insurance may be inadequate to cover all such losses.

The Registrants are subject to risks associated with climate change (All Registrants).

The Registrants periodically perform analyses to better understand long-term projections of climate change and how those changes in the physical environments where they operate could affect their facilities and operations. The Registrants primarily operate in the Midwest and Mid-Atlantic of the United States, areas that historically have been prone to various types of severe weather events, and the Registrants have well-developed response and recovery programs based on these historical events. However, the Registrants' physical facilities could be at greater risk of damage as changes in the global climate affect temperature and weather patterns, including if such climate changes result in more intense, frequent and extreme weather events, elevated or decreased levels of precipitation, sea level rise, increased temperatures, wildfires and/or other effects.

In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect Registrants' operations and business.

The Registrants' businesses are capital intensive, and their assets could require significant expenditures to maintain, are subject to operational failure and could be impacted by disruptions or cost increases in the supply chain, including shortages in labor, materials or parts, or significant increases in relevant tariffs which could result in potential liability (All Registrants).

The Utility Registrants' businesses are capital intensive and require significant investments in transmission and distribution infrastructure projects. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Utility Registrants' control, and could require significant expenditures to operate efficiently. Disruptions or cost increases in the supply chain, including shortages in labor, materials or parts, or significant increases in relevant tariffs, could materially impact the timing and execution of capital projects, and the timing of placing assets in service, as well as other aspects of the Registrants' businesses. In recent years, the energy industry has been experiencing shortages of, and long lead times for, critical equipment such as transformers and conductors. The Registrants' consolidated financial statements could be negatively affected if they were unable to effectively manage their capital projects or raise the necessary capital, or if they are deemed liable for operational failure. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources for additional information regarding the Registrants' potential future capital expenditures.

Lack of sufficient generation and energy storage to meet actual or forecasted demand or disruptions at power generation facilities owned by third parties could interrupt transmission and distribution services, impair economic development, cause outages, and result in use limitations or affordability implications for customers. (All Registrants)

Exelon does not generate the electricity it delivers. The Utility Registrants purchase, transmit, and distribute electric power obtained from power generation facilities owned by third parties. This power is primarily procured through contracts as directed by the Utility Registrants' respective state laws and regulatory commission actions from various approved bidders or from purchases on the PJM operated markets. Third-party power generation may be insufficient to meet our customers' electricity demand in the short- and medium-term because of extreme weather, fuel security, market procurement, regulatory requirements, operational issues, maintenance outages, inflexibility of demand, or financial uncertainty impacting existing or prospective generation facilities. Faster energy demand growth, acceleration of generator retirements, or the limited entry of new generating resources in any of the Utility Registrants' respective service territories may result in a longer-term power generation capacity shortfall. Exelon has forecast substantial increases in load, driven largely by the increasing use of data processing facilities dedicated to cloud services, artificial intelligence technologies, and other applications. If third-party power generation capacity is insufficient to meet any Utility Registrant's customers' electricity demand or customers' electricity demand across PJM over any period, transmission and distribution services may be diminished or interrupted, and results of operations, financial condition, and cash flows could be adversely affected.

In the event generation capacity is insufficient to meet demand, the Utility Registrants' customers may experience greater price volatility, power service outages during peak demand periods or during generation contingencies (e.g., severe storms), and electricity use limits to maintain system balance. Furthermore, the Utility Registrants may be unable to support new economic development should generation constraints last for extended periods.

Energy storage systems provide additional resources for enhancing grid reliability and stability by providing rapid response capabilities, allowing the injection and absorption of power during electric supply and demand imbalances. As forecasted load increases, the lack of sufficient energy storage growth may also lead to greater price volatility and challenges in power services for customers.

The Utility Registrants' respective ability to deliver electricity, their operating costs, and their capital expenditures could be negatively impacted by the insufficiency of generation or energy storage resources to meet demand, transmission congestion, and failures of neighboring transmission systems (All Registrants).

Demand for electricity within the Utility Registrants' service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants' ability to comply with reliability standards and strain customer and regulatory agency relationships. As is the case for electric utilities generally, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring the Utility Registrants to upgrade or expand their respective transmission systems through additional capital expenditures. Delays in siting, permitting, and interconnection could defer the introduction of new generation or energy storage resources that could address resource adequacy concerns.

PJM's systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities. However, service interruptions at other utilities may cause interruptions in the Utility Registrants' service areas. Additionally, efforts to artificially manipulate power demand on the grid, or even accidental activity that results in sharp fluctuations of demand, could disrupt grid operations.

The Registrants' performance could be negatively affected if they fail to attract and retain an appropriately qualified workforce (All Registrants).

Certain factors, such as employee strikes, work stoppages, loss of employees, loss of contract resources due to a major event, inability to negotiate future collective bargaining agreements on commercially reasonable terms, an aging workforce, mismatching of skill sets for current and future needs, and failing to appropriately anticipate future workforce needs, could lead to operating challenges and increased costs for the Registrants. Such challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. Such events and other factors could result in increased costs, including costs of replacing lost labor through contractors or new hires, training costs, and costs of lost productivity. Such events also could increase operational risks. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees needed to conduct Registrants' transmission and distribution operations as well as areas where new technologies are pertinent.

The Registrants' performance could be negatively affected by poor performance of third-party contractors that perform periodic or ongoing work (All Registrants).

The Registrants rely on third-party contractors to perform operations, maintenance, and construction work. Performance standards typically are included in all contractual obligations, but poor performance may impact capital execution plans or operations, or have adverse financial, regulatory, or reputational consequences.

The Registrants could make acquisitions or investments in new business initiatives and new markets, which may not be successful or achieve the intended financial results (All Registrants).

The Utility Registrants face risks associated with regulator-mandated or other new business initiatives, such as smart grids and broader beneficial electrification. Such risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity, and obsolescence of technology. Such initiatives may not be successful, and failures could result in adverse financial or reputational consequences.

Risks Related to Market and Financial Factors

The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry (All Registrants).

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

These developments could affect levels of customer-owned generation, customer expectations, and current business models and make portions of the Utility Registrants' transmission and/or distribution facilities uneconomic prior to the end of their useful lives. Increasing pressure from both the private and public sectors to take actions to mitigate climate change could also push the speed and nature of this transition. These factors could affect the Registrants’ consolidated financial statements through, among other things, increased Operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation over shortened remaining asset useful lives.

The Registrants could be negatively affected by unstable capital and credit markets (All Registrants).

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs. Disruptions in the capital and credit markets in the United States or abroad could negatively affect the Registrants’ ability to access the capital markets or draw on their respective bank revolving credit facilities. The banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets because of uncertainty, changing or increased regulation, reduced alternatives, or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, or require a reduction in dividend payments or other discretionary uses of cash. In addition, the Registrants have exposure to worldwide financial markets, including Europe, Canada, and Asia. Disruptions in these markets could reduce or restrict the Registrants’ ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2025, approximately 17%, 11%, and 17% of the Registrants’ available credit facilities were with European, Canadian, and Asian banks, respectively. Additionally, higher interest rates may put pressure on the Registrants’ overall liquidity profile, financial health and impact financial results. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its counterparties or regulatory financial requirements, it would be required to provide significant

amounts of collateral that could affect its liquidity and could experience higher borrowing costs (All Registrants).

The Utility Registrants' operating agreements with PJM and PECO's, BGE's, and DPL's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and the Utility Registrants were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their remaining sources of liquidity. PJM collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO, BGE, and DPL, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. If the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade. In addition, changes in ratings methodologies by the agencies could also have an adverse negative impact on the ratings of the Utility Registrants.

The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as “ring-fencing”) could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant.

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

The impacts of significant economic downturns or increases in customer rates, could lead to decreased volumes delivered and increased expense for uncollectible customer balances (All Registrants).

The impacts of significant economic downturns on the Utility Registrants' customers and the related regulatory limitations on residential service terminations for the Utility Registrants, could result in an increase in the number of uncollectible customer balances and related expense. Further, increases in customer rates, including those related to increases in Purchased power and natural gas prices, could result in declines in customer usage and lower revenues for the Utility Registrants that do not have decoupling mechanisms.

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

The Registrants could be negatively affected by the impacts of weather (All Registrants).

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting operating revenues at PECO and DPL Delaware. Due to revenue decoupling, operating revenues from electric distribution at ComEd, BGE, Pepco, DPL Maryland, and ACE and gas distribution at BGE are not intended to be affected by abnormal weather.

Extreme weather conditions or damage resulting from storms could stress the Utility Registrants' transmission and distribution systems, communication systems, and technology, resulting in increased maintenance and capital costs and limiting each Utility Registrant's ability to meet peak customer demand. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant.

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

Long-lived assets, goodwill, and other assets could become impaired (All Registrants).

Long-lived assets represent the single largest asset class on the Registrants' statements of financial position. In addition, Exelon, ComEd, and PHI have material goodwill balances.

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

ComEd and PHI perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's, and ACE's business, and the fair value of debt, could potentially result in future impairments of Exelon's, ComEd's, and PHI's goodwill.

An impairment would require the Registrants to reduce the carrying value of the long-lived asset or goodwill to fair value through a non-cash charge to expense by the amount of the impairment. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates, Note 6 — Property, Plant, and Equipment, Note N/A — Asset Impairments, and Note 10 — Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional information on long-lived asset impairments and goodwill impairments.

The Registrants could incur substantial costs in the event of non-performance by third-parties under indemnification agreements, or when the Registrants have guaranteed their performance (All Registrants).

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations. Each of the Utility Registrants has transferred its former generation assets to one or more third parties and in each case the transferee has agreed to assume certain obligations and to indemnify the applicable Utility Registrant for such obligations. In connection with the restructurings under which ComEd, PECO, and BGE transferred their generating assets to Constellation, Constellation assumed certain of ComEd's, PECO's, and BGE's rights and obligations with respect to their former generation assets. Further, ComEd, PECO, and BGE have entered into agreements with third parties under which the third-party agreed to indemnify ComEd, PECO, or BGE for certain obligations related to their respective former generation assets that have been assumed by Constellation as part of the restructuring. If Constellation or a transferee of one of the Utility Registrant's generation assets experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, the applicable Utility Registrant could be liable for any existing or future claims. In addition, the Utility Registrants have residual liability under certain laws in connection with their former generation assets.

The Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets, including several of the Utility Registrants in connection with Constellation's absorption of their former generating assets. The Registrants could incur substantial costs to fulfill their obligations under these indemnities.

The Registrants have issued guarantees of the performance of third parties, which obligate the Registrants to perform if the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees.

Market performance and other factors could decrease the value of employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding (All Registrants).

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Exelon’s employee benefit plan trusts. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below Exelon's projected return rates. A decline in the market value of the pension and OPEB plan assets would increase the funding requirements associated with Exelon’s pension and OPEB plan obligations. Additionally, Exelon’s pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. See Note 12 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

ITEM 1C. CYBERSECURITY

Risk management and strategy

Cybersecurity risk for all Registrants is managed at the enterprise-level. Management of material risks from cybersecurity threats is integrated into the Registrants' overall risk management processes and is monitored as an enterprise risk. Exelon's Chief Information Security Officer (CISO) and cybersecurity management team regularly hold meetings with senior management of each Registrant, facilitated by Exelon’s enterprise risk management team, to discuss issues pertaining to cybersecurity risk management, including changes in the nature and origin of threats, threat actor and risk mitigation activities, and regulatory developments. Exelon legal and compliance professionals engage with the CISO and cybersecurity management team to address tactical and strategic cybersecurity risks. Exelon monitors cybersecurity risks through key risk indicators to identify potential changes in risk exposure and provide the Board of Directors with information about the monitoring of key risks in connection with its oversight of the Registrants' enterprise risk management system.

The CISO, through Exelon’s Cyber Information and Security Services (CISS), reviews external and internal sources to obtain cyber threat intelligence to develop strategic and tactical threat assessments that inform the enterprise-wide cyber risk mitigation programs and actions. Exelon uses a wide range of tools, including endpoint, anomaly and network detection, logging and monitoring of security events, network segmentation, firewalls, hardening and securing devices, cyber vulnerability detection and patch management, cyber threat hunting, malware forensic analysis, industry-specific reports, and tabletop exercises to inform the cybersecurity management team. Exelon protects assets critical to grid reliability and national security through the implementation of the North American Electric Reliability Corporation’s Critical Infrastructure Protection requirements, and gas pipeline security under the U.S. Department of Homeland Security’s Transportation Safety Administration’s Security Directives. Exelon maintains security relationships with law enforcement and U.S. intelligence agencies, coordinates with the Electricity Information Sharing and Analysis Center (E-ISAC) and participates in the Department of Energy’s Cybersecurity Risk Information Sharing Program (CRISP) to strengthen the security of the energy grid, share information, design and participate in drills and exercises such as the bi-annual Grid Security Exercises and facilitate cross-sector coordination. Exelon applies stringent employee and contractor screening, and advances security awareness through training and monitoring programs that address both cyber and physical threats. Exelon employees are subject to annual mandatory training addressing security awareness, including cybersecurity and phishing. Exelon maintains cyber insurance coverage at limits consistent with the utility industry and reviews policy coverage and limits on an annual basis.

In assessing the effectiveness of its cybersecurity risk management program, the CISO makes use of external perspectives from regulatory compliance audits and inspections, external audits of the Registrants' financial systems, and third-party incident response and detection analytics. Cybersecurity risks associated with the Registrants’ use of certain third-party service providers are evaluated and managed through CISS' Third Party Security team that leverages security risk assessments, contractual terms and conditions, and security awareness training for such providers. Additionally, those providers are required to report cybersecurity incidents, including the unauthorized use or disclosure of Registrants’ confidential information to Exelon’s security operations center. Third Party Security investigates certain third-party cybersecurity events as part of Exelon’s incident response program.

Governance

The Operations, Safety and Customer Experience Committee (OSCC) and Exelon Board of Directors are responsible for oversight of risks from cybersecurity threats. As documented in the Cybersecurity Oversight Policy, the Board of Directors oversees Exelon's cybersecurity program and Exelon’s enterprise-wide risk related to cybersecurity, including management’s identification, assessment, and mitigation of cybersecurity risks. At each regular quarterly meeting, the OSCC engages with the CISO and a cross-functional management team regarding the risks from cybersecurity threats, and the Board of Directors receives reports on cybersecurity risks at least annually. The CISO and professionals from the legal and compliance departments brief the OSCC on relevant topics, including information security and operational security, legislative and regulatory developments, and notable external cyber events relevant to Exelon and the industry more broadly. Management engages with the OSCC and the Board of Directors on risks from cybersecurity threats as appropriate outside of the quarterly meetings.

The CISO manages Exelon's enterprise-wide cybersecurity programs and reports to Exelon’s Chief Information Officer. The CISO has been responsible for assessing and managing material risks from cybersecurity threats at Exelon since 2018 and was named to the current role in 2022. The CISO has 26 years of information technology and cybersecurity experience in the critical infrastructure sector, of which 24 years have been in the utility industry. The CISO leads CISS, which manages centralized information technology and operational technology security programs for the Registrants. The programs are aligned to the National Institute of Standards and Technology Cyber Security Framework (NIST CSF) and integrate cyber asset identification; threat assessment; risk assessment; risk management; and risk monitoring. CISS operates a security operations center for monitoring, identifying, and mitigating potential cybersecurity events or incidents.

Exelon maintains a single, centralized cybersecurity incident response program and plan that aligns with NIST CSF by integrating the identify, determine/classify, escalate and respond functions (which track the lifecycle of an event or incident). Security threats and incidents are identified and assessed to determine potential impact and escalated to senior cybersecurity management and the CISO. The CISO directs the security incident response team to contain, eradicate, and recover from an active threat. Exelon leverages the expertise of dedicated incident response vendors that can provide timely and specialized support to respond and recover from an event. The CISO and a cross-functional team convene as needed to evaluate cybersecurity events, including third-party events. The legal and compliance departments provide incident response support to the CISO, manage cybersecurity-related legal and compliance issues, and direct materiality evaluations using both qualitative and quantitative factors for each Registrant.

Although the Registrants have not experienced any material cybersecurity events to date, cybersecurity threats could materially affect each Registrant’s business strategy, results of operations, or financial condition, as further discussed in the risk factor entitled “The Registrants are subject to physical and cybersecurity risks" in ITEM 1A. of this report.

ITEM 2. PROPERTIES

The Utility Registrants

The Utility Registrants' electric substations and a portion of their transmission rights are located on property that they own. A significant portion of their electric transmission and distribution facilities are located above or underneath highways, streets, other public places, or property that others own. The Utility Registrants believe that they have satisfactory rights to use those places or property in the form of permits, grants, easements, licenses, and franchise rights; however, they have not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

The Utility Registrants’ high voltage electric transmission lines owned and in service as of December 31, 2025 were as follows:

Voltage	Circuit Miles					
(Volts)	ComEd	PECO	BGE	Pepco	DPL	ACE
765,000	90	—	—	—	—	—
500,000[(a)]	—	191	216	109	16	—
345,000	2,678	—	—	—	—	—
230,000	—	550	352	794	472	259
138,000	2,268	135	55	61	587	215
115,000	—	—	700	26	—	—
69,000	—	178	—	—	570	675

(a) In addition, PECO, DPL, and ACE have an ownership interest located in Delaware and New Jersey. See Note 7 — Jointly Owned Electric Utility Plant of the Combined Notes to the Consolidated Financial Statements for additional information.

The Utility Registrants' electric distribution system includes the following number of circuit miles of overhead and underground lines as of December 31, 2025:

Circuit Miles	ComEd	PECO	BGE	Pepco	DPL	ACE
Overhead	35,349	12,972	9,101	4,172	6,014	7,349
Underground	33,180	9,898	18,262	7,412	6,715	3,149

Gas

The following table presents PECO’s, BGE’s, and DPL’s natural gas pipeline miles as of December 31, 2025.

	PECO	BGE	DPL
Transmission[(a)]	6	146	8
Distribution	7,349	7,651	2,183
Service piping	6,590	6,556	1,502
Total	13,945	14,353	3,693

(a) DPL has a 10% undivided interest in approximately 8 miles of natural gas transmission mains located in Delaware, which are used by DPL for its natural gas operations and by 90% owner for distribution of natural gas to its electric generating facilities.

The following table presents PECO's, BGE's, and DPL's natural gas facilities as of December 31, 2025.

Registrant	Facility	Location	Storage Capacity (mmcf)	Send-out or Peaking Capacity (mmcf/day)
PECO	LNG Facility	West Conshohocken, PA	1,200	195
PECO	Propane Air Plant	Chester, PA	105	25
BGE	LNG Facility	Baltimore, MD	1,056	332
BGE	Propane Air Plant	Baltimore, MD	550	85
DPL	LNG Facility	Wilmington, DE	250	60

PECO, BGE, and DPL also own 30, 27, and 10 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout their gas service territory, respectively.

First Mortgage and Insurance

The principal properties of ComEd, PECO, Pepco, DPL, and ACE are subject to the lien of their respective mortgages under which their respective First Mortgage Bonds are issued. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

The Utility Registrants maintain property insurance against loss or damage to their properties by fire or other perils, subject to certain exceptions. For their insured losses, the Utility Registrants are self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect in the consolidated financial condition or results of operations of the Utility Registrants.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes, and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

All Registrants

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Note 2 — Regulatory Matters and Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable

PART II

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

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

Exelon

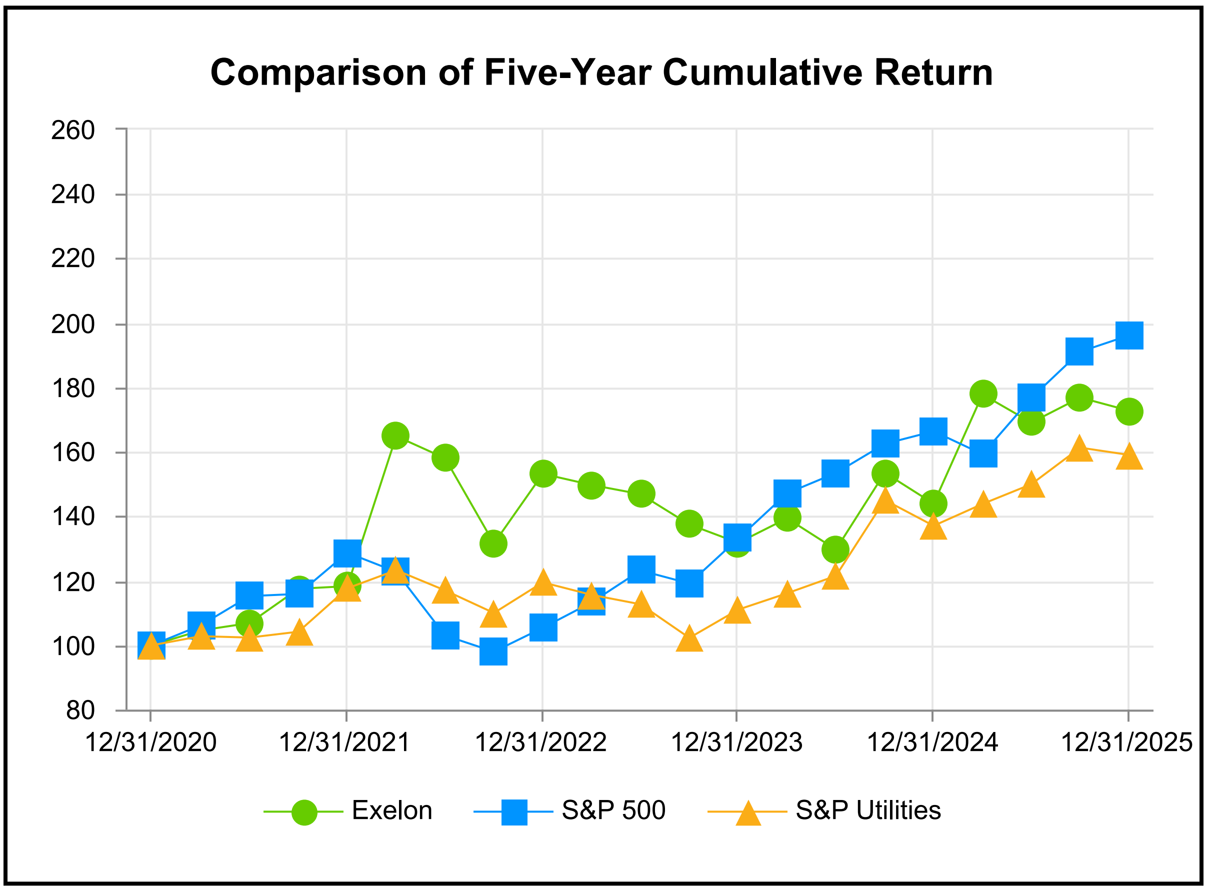
Exelon's common stock is listed on the Nasdaq (trading symbol: EXC). As of January 31, 2026, there were 1,022,892,585 shares of Common stock outstanding and approximately 68,884 record holders of Common stock.

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon Common stock, compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2021 through 2025. Cumulative total returns account for the separation of Constellation, as the spin-off dividend was assumed to have been reinvested upon receipt.

This performance chart assumes:

- $100 invested on December 31, 2020 in Exelon Common stock, the S&P 500 Stock Index, and the S&P Utility Index; and
- All dividends are reinvested.



Value of Investment at December 31,						
	2020	2021	2022	2023	2024	2025
Exelon Corporation	$100.00	$141.41	$153.19	$131.78	$143.93	$172.79
S&P 500	$100.00	$128.71	$105.40	$133.10	$166.40	$196.16
S&P Utilities	$100.00	$117.67	$119.51	$111.05	$137.07	$159.06

ComEd

As of January 31, 2026, there were 127,021,422 outstanding shares of Common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. As of January 31, 2026, in addition to Exelon, there were 277 record holders of ComEd Common stock. There is no established market for shares of the Common stock of ComEd.

PECO

As of January 31, 2026, there were 170,478,507 outstanding shares of Common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2026, there were 1,000 outstanding shares of Common stock, without par value, of BGE, all of which were indirectly held by Exelon.

PHI

As of January 31, 2026, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2026, there were 100 outstanding shares of Common stock, $0.01 par value, of Pepco, all of which were indirectly held by Exelon.

DPL

As of January 31, 2026, there were 1,000 outstanding shares of Common stock, $2.25 par value, of DPL, all of which were indirectly held by Exelon.

ACE

As of January 31, 2026, there were 8,546,017 outstanding shares of Common stock, $3.00 par value, of ACE, all of which were indirectly held by Exelon.

All Registrants

Dividends

Under applicable Federal law, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE can pay dividends only from retained, undistributed, or current earnings. A significant loss recorded at ComEd, PECO, BGE, PHI, Pepco, DPL, or ACE may limit the dividends that these Registrants can distribute to Exelon.

ComEd has agreed, in connection with a financing arranged through ComEd Financing III, that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed, in connection with financings arranged through PEC L.P. and PECO Trust IV, that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to restrictions established by the MDPSC that prohibit BGE from paying a dividend on its common shares if (a) after the dividend payment, BGE’s equity ratio would be below 48% as calculated pursuant to the MDPSC’s ratemaking precedents or (b) BGE’s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. No such event has occurred.

Pepco is subject to certain dividend restrictions established by settlements approved by the MDPSC and DCPSC that prohibit Pepco from paying a dividend on its common shares if (a) after the dividend payment, Pepco's equity ratio would be below 48% as calculated pursuant to the MDPSC's and DCPSC's ratemaking precedents, or (b) Pepco’s senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.

DPL is subject to certain dividend restrictions established by settlements approved by the DEPSC and MDPSC that prohibit DPL from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be below 48% as calculated pursuant to the DEPSC's and MDPSC's ratemaking precedents, or (b) DPL’s corporate issuer or senior unsecured credit rating, or its equivalent, is rated by any of the three major credit rating agencies below the generally accepted definition of investment grade. No such event has occurred.

ACE is subject to certain dividend restrictions established by settlements approved by the NJBPU that prohibit ACE from paying a dividend on its common shares if (a) after the dividend payment, ACE's common equity ratio would be below 48% as calculated pursuant to the NJBPU's ratemaking precedents, or (b) ACE's senior corporate issuer or senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. ACE is also subject to a dividend restriction which requires ACE to notify and obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%. No such event has occurred.

Exelon’s Board of Directors approved an updated dividend policy for 2026. The 2026 quarterly dividend will be $0.42 per share.

As of December 31, 2025, Exelon had Retained earnings of $7,577 million, ComEd had Retained earnings of $2,998 million, PECO had Retained earnings of $2,438 million, BGE had Retained earnings of $2,588 million, and PHI had Undistributed losses of $151 million.

The following table sets forth Exelon’s quarterly cash dividends per share paid during 2025 and 2024:

	2025				2024			
(per share)	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Exelon	$ 0.4000	$ 0.4000	$ 0.4000	$ 0.4000	$ 0.3800	$ 0.3800	$ 0.3800	$ 0.3800

The following table sets forth PHI's quarterly distributions and ComEd’s, PECO’s, BGE's, Pepco's, DPL's, and ACE's quarterly common dividend payments:

	2025				2024			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
ComEd	$ 203	$ 203	$ 204	$ 203	$ 194	$ 194	$ 194	$ 194
PECO	136	137	136	137	100	100	100	100
BGE	99	98	98	98	92	92	92	92
PHI	162	256	160	132	157	267	164	118
Pepco	60	109	92	66	73	133	102	51
DPL	53	59	44	46	58	78	39	45
ACE	51	88	24	20	27	56	22	22

First Quarter 2026 Dividend

On February 12, 2026, Exelon's Board of Directors declared a regular quarterly dividend of $0.42 per share on Exelon’s Common stock for the first quarter of 2026. The dividend is payable on Friday, March 13, 2026, to shareholders of record of Exelon as of the close of business on Monday, March 2, 2026.

ITEM 6. [RESERVED]

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

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

Exelon

Executive Overview

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through its six reportable segments: ComEd, PECO, BGE, Pepco, DPL, and ACE. See Note 1 — Significant Accounting Policies and Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

Exelon’s consolidated financial information includes the results of its seven separate operating subsidiary registrants, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management’s Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants. For discussion of the Utility Registrants' year ended December 31, 2024 compared to the year ended December 31, 2023, refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the 2024 Form 10-K, which was filed with the SEC on February 12, 2025.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net income attributable to common shareholders by Registrant for the year ended December 31, 2025 compared to the same period in 2024. For additional information regarding the financial results for the years ended December 31, 2025 and 2024, see the discussions of Results of Operations by Registrant.

	2025	2024	Favorable (Unfavorable) Variance
Exelon	$ 2,768	$ 2,460	$ 308
ComEd	1,147	1,066	81
PECO	814	551	263
BGE	578	527	51
PHI	799	741	58
Pepco	401	390	11
DPL	224	209	15
ACE	188	155	33
Other[a]	(570)	(425)	(145)

(a) Other primarily includes eliminating and consolidating adjustments, Exelon’s corporate operations, shared service entities, and other financing and investing activities.

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. **Net income attributable to common shareholders** increased by $308 million and Diluted earnings per average common share increased to $2.73 in 2025 from $2.45 in 2024 primarily due to:

- Favorable impacts of rate increases at ComEd, PECO, BGE, and PHI;
- Favorable weather at PECO;
- Higher return on regulatory assets at ComEd;
- Higher AFUDC at ComEd;
- Lower income tax expense at PECO;
- Lower storm costs at BGE; and
- Impacts of the multi-year plan reconciliation at BGE.

Note that rate increases are associated with updated recovery rates for costs and investments to serve customers. The increases were partially offset by:

- Higher interest expense at PECO, BGE, PHI, and Exelon Corporate;
- Higher depreciation expense at PECO and PHI;
- Higher contracting costs at PECO and PHI;
- Lower transmission peak load due to lower energy demand at ComEd;
- Absence of the Maryland multi-year plan reconciliations at PHI;
- Charitable contributions at Exelon Corporate;
- Lower AFUDC at PHI; and
- Higher income tax expense at Exelon Corporate.

Adjusted (non-GAAP) operating earnings. In addition to Net income, Exelon evaluates its operating performance using the measure of Adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses, and other specified items. This information is intended to enhance an investor’s overall understanding of year-over-year operating results and provide an indication of Exelon’s baseline operating performance excluding items not considered by management to be directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets, and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings 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.

The following table provides a reconciliation between Net income attributable to common shareholders as determined in accordance with GAAP and Adjusted (non-GAAP) operating earnings for the year ended December 31, 2025 compared to 2024:

(In millions, except per share data)	2025	2025 Earnings per Diluted Share	2024	2024 Earnings per Diluted Share
Net income attributable to common shareholders	**$ 2,768**	**$ 2.73**	**$ 2,460**	**$ 2.45**
Asset retirement obligations (net of taxes of $0 and $3, respectively)	(1)	—	8	0.01
Change in FERC audit liability (net of taxes of $1 and $13, respectively)	2	—	42	0.04
Cost management charge (net of taxes of $0 and $4, respectively)[a]	(1)	—	13	0.01
Environmental costs (net of taxes of $5)	—	—	(13)	(0.01)
Regulatory matters (net of taxes of $10)[b]	30	0.03	—	—
Income tax-related adjustments (entire amount represents tax expense)[c]	1	—	(3)	—
Adjusted (non-GAAP) operating earnings	**$ 2,801**	**$ 2.77**	**$ 2,507**	**$ 2.50**

Note:
Amounts may not sum due to rounding.
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net income and Adjusted (non-GAAP) operating earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. The marginal statutory income tax rates for 2025 and 2024 ranged from 24.0% to 29.0%.

(a) Primarily represents severance and reorganization costs related to cost management.
(b) Represents the disallowance of certain capitalized costs.
(c) In 2024, reflects the adjustment to state deferred income taxes due to change in DPL's Delaware net operating loss valuation allowance. In 2025, reflects the adjustment to state deferred income taxes due to changes in forecasted apportionment.

Significant 2025 Transactions and Developments

At-the-Market Program

During 2025, Exelon issued approximately 16 million shares of Common Stock at a net weighted-average price of $43.24 per share. The net proceeds from the 2025 issuances were $691 million, which were used for general corporate purposes. See Note 17 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

Distribution Base Rate Case Proceedings

The Utility Registrants file base rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants' current and future financial statements.

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2025. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these and other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	January 17, 2023	Electric	$ 1,487	$ 1,045	8.905%	December 19, 2024	January 1, 2024
	April 26, 2024 (amended on September 11, 2024)	Electric	$ 624	$ 623	9.89%	October 31, 2024	January 1, 2025
PECO - Pennsylvania	March 28, 2024	Electric	$ 464	$ 354	N/A	December 12, 2024	January 1, 2025
		Natural Gas	$ 111	$ 78			
BGE - Maryland	February 17, 2023	Electric	$ 313	$ 179	9.50%	December 14, 2023	January 1, 2024
		Natural Gas	$ 289	$ 229	9.45%		
Pepco - District of Columbia	April 13, 2023 (amended February 27, 2024)	Electric	$ 186	$ 123	9.50%	November 26, 2024	January 1, 2025
Pepco - Maryland	May 16, 2023 (amended February 23, 2024)	Electric	$ 111	$ 45	9.50%	June 10, 2024	April 1, 2024
DPL - Maryland	May 19, 2022	Electric	$ 38	$ 29	9.60%	December 14, 2022	January 1, 2023
DPL - Delaware	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	$ 28	9.60%	April 18, 2024	July 15, 2023
	September 20, 2024 (amended September 5, 2025)	Natural Gas	$ 37	$ 22	9.60%	December 17, 2025	January 1, 2026
ACE - New Jersey	February 15, 2023 (amended August 21, 2023)	Electric	$ 92	$ 45	9.60%	November 17, 2023	December 1, 2023
	November 21, 2024	Electric	$ 109	$ 54	9.60%	November 21, 2025	December 1, 2025

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Pepco - Maryland	October 14, 2025	Electric	$ 133	10.50%	Third quarter of 2026
DPL - Delaware	December 9, 2025	Electric	$ 45	10.50%	Third quarter of 2027

Transmission Formula Rates

The following total increases/(decreases) were included in the Utility Registrants' 2025 annual electric transmission formula rate updates. All rates are effective June 1, 2025 to May 31, 2026, subject to review by interested parties pursuant to review protocols of each Utility Registrants' tariff. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase (Decrease)	Annual Reconciliation Increase (Decrease)	Total Revenue Requirement Increase (Decrease)	Allowed Return on Rate Base	Allowed ROE
ComEd	$ 78	$ 49	$ 127	8.13 %	11.50 %
PECO	$ 9	$ 13	$ 22	7.54 %	10.35 %
BGE	$ 21	$ 21	$ 35	7.53 %	10.50 %
Pepco	$ 35	$ 16	$ 51	7.71 %	10.50 %
DPL	$ 32	$ (9)	$ 23	7.48 %	10.50 %
ACE	$ (11)	$ (46)	$ (57)	7.16 %	10.50 %

ComEd's FERC Audit

The Utility Registrants are subject to periodic audits and investigations by FERC. FERC’s Division of Audits and Accounting initiated a nonpublic audit of ComEd in April 2021 evaluating ComEd’s compliance with (1) approved terms, rates and conditions of its federally regulated service; (2) accounting requirements of the Uniform System of Accounts; (3) reporting requirements of the FERC Form 1; and (4) the requirements for record retention. The audit period extended back to January 1, 2017.

On July 27, 2023, FERC published a final audit report which included, among other things, findings and recommendations related to ComEd's methodology regarding the allocation of certain overhead costs to capitalized construction costs under FERC regulations, including a suggestion that refunds may be due to customers for amounts collected in previous years. On July 30, 2024, ComEd reached an agreement in principle on the contested overhead allocation finding. As a result of the settlement process, ComEd recorded a charge for the probable disallowance of $70 million of certain currently capitalized construction costs to operating expenses, which are not expected to be recovered in future rates. The existing loss estimate was reflected in Exelon and ComEd's financial statements as of December 31, 2024. ComEd and FERC staff jointly filed the settlement agreement with FERC for approval on February 11, 2025. The settlement was approved by FERC on April 4, 2025.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants’ current and future results of operations, cash flows, and financial positions. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these regulatory proceedings.

Allocation of Income Taxes to Regulated Utilities (All Registrants)

In Q2 2024, the IRS issued a series of PLRs, to another taxpayer, providing guidance with respect to the application of the tax normalization rules to the allocation of consolidated tax benefits among the members of a consolidated group associated with NOLC for ratemaking purposes. The rulings provide that for ratemaking purposes the tax benefit of NOLC should be reflected on a separate company basis not taking into consideration the utilization of losses by other affiliates. A PLR issued to another taxpayer may not be relied on as precedent.

For the Utility Registrants, except for PECO, the methodology prescribed by the IRS in these PLRs could result in a material reduction of the regulatory liability established for EDITs arising from the TCJA corporate tax rate change that are being amortized and flowed through to customers as well as a reduction in the accumulated deferred income taxes included in rate base for ratemaking purposes of approximately $1.2 billion - $1.7 billion.

The Utility Registrants, except for PECO, filed PLR requests with the IRS confirming the treatment of the NOLC for ratemaking purposes. The Utility Registrants will record the impact, if any, upon receiving the PLR from the IRS.

Legislative and Regulatory Developments

Infrastructure Investment and Jobs Act

On November 15, 2021, the $1.2 trillion IIJA was signed into law. IIJA provides for approximately $550 billion in new federal spending. Categories of funding include funding for a variety of infrastructure needs, including but not limited to: (1) power and grid reliability and resilience, (2) resilience for cybersecurity to address critical infrastructure needs, and (3) electric vehicle charging infrastructure for alternative fuel corridors. The Registrants continue to evaluate programs under the legislation and consider possible opportunities to apply for funding, either directly or in potential collaborations with state and/or local agencies and key stakeholders. The Registrants cannot predict the ultimate timing and success of securing funding from programs under IIJA.

On January 20, 2025, the Unleashing American Energy Order was issued as a Presidential Executive Order, which required an immediate pause in the disbursement of funds appropriated through the IRA and IIJA pending DOE review. In October 2025, Exelon, ComEd, and BGE received termination notifications from the DOE for their Renewable-Aware Distribution Operations, Deployment of a Community-Oriented Interoperable Control Framework for Aggregating and Integrating Distributed Energy Resources and Other Grid-Edge Devices, and Baltimore Interconnection Readiness & Deployment of Storage (BIRDS) awards, respectively. In the fourth quarter of 2025, Exelon, ComEd, and BGE elected to decline the previously awarded Middle Mile Grant (MMG) and Exelon and PECO elected to decline the previously awarded Creating a Resilient, Equitable, and Accessible Transformation in Energy for Greater Philadelphia (CREATE) grant. There are no material financial statement impacts as a result of the DOE terminations. Exelon, ComEd, PECO, and BGE will continue to evaluate whether to move forward with these projects.

Next Generation Energy Act (Exelon, BGE, PHI, Pepco, and DPL)

On May 20, 2025, the Governor of Maryland signed into law legislation that addresses several matters pertaining to electric and gas utilities, including affirming that the MDPSC may approve the use of multi-year rate plans that demonstrate customer benefits, among other things. It also prohibits utilities from filing after January 1, 2025, for the reconciliation of actuals costs and revenues to amounts approved within the multi-year plans. In the second quarter of 2025, BGE derecognized Regulatory assets of $10 million and Regulatory liabilities of $3 million for multi-year plan reconciliations that are no longer eligible to be filed. DPL also derecognized Regulatory liabilities of $0.4 million during the second quarter of 2025 for multi-year reconciliations ineligible to be filed. Multi-year plan reconciliations filed prior to January 1, 2025, remain lawful and will be resolved in their respective proceedings.

Summer and Winter Rate Mitigation (Exelon, BGE, PHI, Pepco, DPL, and ACE).

As part of the passing of the Next Generation Energy Act by the Maryland General Assembly, the MDPSC issued an order on June 26, 2025, to implement the Legislative Energy Relief Refund program under which bill credits were distributed to residential customers based on their consumption of electricity supply that was subject to the renewable energy portfolio standard. On July 24, 2025, the MDPSC issued an order accepting BGE, Pepco, and DPL's proposal for the implementation of the program. As a result, BGE, Pepco, and DPL received approximately

$49 million, $21 million, and $8 million, respectively, from the MDPSC on August 6, 2025. These amounts were used to reduce residential customer accounts receivable balances within the third quarter of 2025. Additional disbursements from the state of Maryland were received by BGE, Pepco, and DPL on February 3, 2026 for approximately $49 million, $21 million, and $8 million, respectively. These amounts will also be used to reduce residential customer receivables in the first quarter of 2026.

In response to significant increases in electric supply costs, on April 23, 2025, the NJBPU issued an order directing the State's electric public utilities to file petitions proposing distribution side measures to mitigate residential customer bill impacts during summer months. As a result, on June 18, 2025, the NJBPU approved a stipulation of settlement for ACE to issue a bill credit of $30 per residential customer for the months of July and August 2025, which was deferred to Regulatory assets. The amounts will subsequently be collected from September 2025 through February 2026 at a flat rate of $10 per residential customer. The bill credit and subsequent collections will not be subject to carrying costs. As of December 31, 2025, the Regulatory asset has a remaining balance of $10 million.

Residential Universal Bill Credit (Exelon and ACE).

In an effort to further reduce the burden of increased electric supply costs, on August 13, 2025, the NJBPU issued an order to establish the Residential Universal Bill Credit (RUBC), which will be funded by the NJBPU. The program provided a $50 bill credit per eligible residential customer for the months of September and October 2025. ACE received $51 million from the NJBPU on September 25, 2025, which was recognized as a Regulatory liability. ACE subsequently issued all bill credits to residential customers in September and October. As of December 31, 2025, there is no Regulatory liability remaining.

One Big Beautiful Bill Act (All Registrants).

On July 4, 2025, the OBBBA was signed into law. The bill permanently extends expiring tax benefits of the TCJA and provides additional tax relief for individuals and businesses while accelerating the phase-out and curtailment for renewable energy tax credits enacted by the IRA. The tax law changes enacted as part of OBBBA will not have a direct material impact on the Registrants’ financial statements.

Critical Accounting Policies and Estimates

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

Regulatory Accounting (All Registrants)

For their regulated electric and gas operations, the Registrants reflect the effects of cost-based rate regulation in their financial statements, which is required for entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities’ cost of providing services or products; and (3) a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) revenue or gains that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. If it is concluded in a future period that a separable portion of operations no longer meets the criteria discussed above, the Registrants would be required to eliminate any associated regulatory assets and liabilities and the impact, which could be material, would be recognized in the Consolidated Statements of Operations and Comprehensive Income.

The following table illustrates gains (losses) to be included in net income that could result from the elimination of regulatory assets and liabilities and charges against OCI related to deferred costs associated with Exelon's pension and OPEB plans that are recorded as Regulatory assets in Exelon's Consolidated Balance Sheets (before taxes) at December 31, 2025:

(In millions)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Gain (loss)	$ 4,482	$ 6,727	$ (758)	$ (353)	$ (1,083)	$ (306)	$ 72	$ (467)
Charge against OCI[(a)]	(2,911)	—	—	—	—	—	—	—

(a) Exelon's charge against OCI (before taxes) consists of up to $2.4 billion, $346 million, $298 million, $214 million, and $75 million, related to ComEd's, BGE's, PHI's, Pepco's, and DPL's respective portions of the deferred costs associated with Exelon's pension and OPEB plans. Exelon also has a net regulatory liability (before taxes) of $86 million and $6 million related to PECO's and ACE's portions of the deferred costs associated with Exelon's OPEB plans that would result in an increase in OCI if reversed.

See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities of the Registrants.

For each regulatory jurisdiction in which they conduct business, the Registrants assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or refund at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in each Registrant's jurisdictions, and factors such as changes in applicable regulatory and political environments. If the assessments and estimates made by the Registrants for regulatory assets and regulatory liabilities are ultimately different than actual regulatory outcomes, the impact in their consolidated financial statements could be material.

Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ICC-approved electric distribution MRP and formula rate mechanisms for ComEd, and FERC transmission formula rate tariffs for the Utility Registrants.

Revenues (All Registrants)

Sources of Revenue and Determination of Accounting Treatment. The Registrants earn revenues from the sale and delivery of power and natural gas in regulated markets. The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily apply the Revenue from Contracts with Customers, and Alternative Revenue Program accounting guidance to recognize revenues as discussed in more detail below.

Revenue from Contracts with Customers. The Registrants recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power and natural gas are physically delivered to the customer. Transactions of the Registrants within the scope of Revenue from Contracts with Customers generally include sales to utility customers under regulated service tariffs.

The determination of the Registrants' power and natural gas sales to individual customers is based on systematic readings of customer meters, generally monthly. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the Registrant’s customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternative supplier, since unbilled commodity revenues are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date also impact the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

Alternative Revenue Program Accounting. Certain of the Registrants' ratemaking mechanisms qualify as ARPs if they (i) are established by a regulatory order and allow for automatic adjustment to future rates, (ii) provide for additional revenues (above those amounts currently reflected in the price of utility service) that are objectively determinable and probable of recovery, and (iii) allow for the collection of those additional revenues within 24 months following the end of the period in which they were recognized. For mechanisms that meet these criteria, the Registrants adjust revenue and record an offsetting regulatory asset or liability once the condition or event allowing additional billing or refund has occurred. The ARP revenues presented in the Registrants' Consolidated Statements of Operations and Comprehensive Income include both: (i) the recognition of "originating" ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the "originating" ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, distributed generation rebates, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its distribution multi-year rate plan, distribution revenue decoupling mechanisms, and formula rate mechanisms. BGE, Pepco, DPL, and ACE record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC, DCPSC, and/or NJBPU in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL, and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. Estimates of the current year revenue requirement are based on actual and/or forecasted costs and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Income Taxes (All Registrants)

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

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

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Allowance for Credit Losses on Customer Receivables (All Registrants)

The Registrants allowance for credit losses on customer receivables is estimated based on historical experience, current conditions, and forward-looking risk factors. Historical experience considered include collection activities and payment history utilized for risk segmentation; current conditions include changes in economic conditions, aging of receivable balances, payment options and programs available to customers, and industry trends for each company; and forward-looking risk factors include assumptions related to the level of write-offs and recoveries. Risk segments represent a group of customers with similar forward-looking credit quality indicators and risk factors that are comprised based on various attributes, including delinquency of their balances and payment history and represent expected, future customer behavior. The Registrants' customer accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. The Registrants' customer accounts are written off consistent with approved regulatory requirements. The Registrants' allowances for credit losses will continue to be affected by changes in volume, prices, and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DEPSC, and NJBPU regulations.

Depreciable Lives of Property, Plant, and Equipment (All Registrants)

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

Depreciation studies generally serve as the basis for amounts allowed in customer rates for recovery of depreciation costs. Generally, the Registrants adjust their depreciation rates for financial reporting purposes concurrent with adjustments to depreciation rates reflected in customer rates, unless the depreciation rates reflected in customer rates do not align with management’s judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Depreciation expense and customer rates for ComEd, BGE, Pepco, DPL, and ACE include an estimate of the future costs of dismantling and removing plant from service upon retirement. See Note 2 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding regulatory liabilities and assets recorded by ComEd, BGE, Pepco, DPL, and ACE related to removal costs.

PECO’s removal costs are capitalized to accumulated depreciation when incurred and recorded to depreciation expense over the life of the new asset constructed consistent with PECO’s regulatory recovery method. Estimates for such removal costs are also evaluated in the periodic depreciation studies.

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

Goodwill (Exelon, ComEd, and PHI)

As of December 31, 2025, Exelon’s $6.6 billion carrying amount of goodwill consists of $2.6 billion at ComEd and $4 billion at PHI. These entities are required to perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. A reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is assessed for impairment. ComEd has a single operating segment and reporting unit. PHI’s operating segments and reporting units are Pepco, DPL, and ACE. See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. Exelon's and ComEd’s goodwill has been assigned entirely to the ComEd reporting unit. Exelon's and PHI’s goodwill has been assigned to the Pepco, DPL, and ACE reporting units in the amounts of $2.1 billion, $1.4 billion, and $0.5 billion, respectively. See Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. As part of the qualitative assessments, Exelon, ComEd, and PHI evaluate, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed.

Application of the goodwill impairment assessment requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, and projected operating and capital cash flows for ComEd’s, Pepco's, DPL's, and ACE's businesses and the fair value of debt.

While the 2025 annual assessments indicated no impairments, certain assumptions used in the assessment are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon’s, ComEd's, or PHI’s goodwill, which could be material.

See Note 1 — Significant Accounting Policies and Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Contract Liabilities (Exelon and PHI)

Unamortized energy contract liabilities represent the remaining unamortized balances of non-derivative electricity contracts that Exelon acquired as part of the PHI merger. The initial amount recorded represents the difference between the fair value of the contracts at the time of acquisition and the contract value based on the terms of each contract. Offsetting regulatory assets were also recorded for those energy contract costs that are probable of recovery through customer rates. The unamortized energy contract liabilities and the corresponding regulatory assets, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization of the unamortized energy contract liabilities are recorded through Purchased power and fuel expense. See Note 2 — Regulatory Matters and Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Accounting for Loss Contingencies (All Registrants)

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

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, regulations, and the requirements of local governmental authorities. Annual studies and/or reviews are conducted at ComEd, PECO, BGE, and DPL to determine future remediation requirements for MGP sites and estimates are adjusted accordingly. In addition, periodic reviews are performed at each of the Registrants to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact in the Registrants’ consolidated financial statements. See Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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

Retirement Benefits (All Registrants)

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

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

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

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

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon’s mortality assumption utilizes the SOA 2019 base table (Pri-2012) and MP-2021 improvement scale adjusted to use Proxy SSA ultimate improvement rates.

Sensitivity to Changes in Key Assumptions. The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant:

	Actual Assumption			(Decrease) Increase		
Actuarial Assumption	Pension	OPEB	Change in Assumption	Pension	OPEB	Total
Change in 2025 cost:						
Discount rate[(a)]	5.68%	5.64%	0.5%	$ (16)	$ (2)	$ (18)
	5.68%	5.64%	(0.5)%	$ 18	$ 2	$ 20
EROA	7.00%	6.50%	0.5%	$ (51)	$ (6)	$ (57)
	7.00%	6.50%	(0.5)%	$ 51	$ 6	$ 57
Change in benefit obligation at December 31, 2025:						
Discount rate[(a)]	5.42%	5.34%	0.5%	$ (485)	$ (79)	$ (564)
	5.42%	5.34%	(0.5)%	$ 552	$ 89	$ 641

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

See Note 1 — Significant Accounting Policies and Note 12 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and OPEB plans.

Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations. See Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlying and one or more notional quantities.

All derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, NPNS. For derivatives that qualify and are designated as cash flow hedges, changes in fair value each period are initially recorded in AOCI and recognized in earnings when the hedged transaction affects earnings. For derivatives intended to serve as economic hedges, which are not designated for hedge accounting, changes in fair value each period are recognized in earnings on the Consolidated Statement of Operations and Comprehensive Income or are recorded as a regulatory asset or liability when there is an ability to recover or return the associated costs or benefits in accordance with regulatory requirements.

NPNS. Contracts that are designated as NPNS are not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for NPNS requires judgment on whether the contract will physically deliver and requires that management ensure compliance with all the associated qualification and documentation requirements. For all NPNS derivative instruments, accounts payable is recorded when derivatives settle and expense is recognized in earnings as the underlying physical commodity is consumed. Contracts that qualify for NPNS are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period, and the contract is not financially settled on a net basis. See Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for all contracts that are accounted for under NPNS.

Commodity Contracts. The Registrants make estimates and assumptions concerning future commodity prices, interest rates, and the timing of future transactions and their probable cash flows in deciding whether to enter derivative transactions, and in determining the initial accounting treatment for derivative transactions. The

Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value.

Derivative contracts can be traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are generally categorized in Level 1 in the fair value hierarchy. Certain derivative pricing is verified using indicative price quotations available through brokers or over-the-counter, online exchanges. For derivatives that trade in liquid markets, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs and are categorized in Level 3.

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

Interest Rate Derivative Instruments. Exelon Corporate utilizes interest rate swaps to manage interest rate risk on existing and planned future debt issuances. The fair value of the swaps is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate derivatives are primarily categorized in Level 2 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 15 — Fair Value of Financial Assets and Liabilities and Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants’ derivative instruments.

Results of Operations by Registrant

Results of Operations—ComEd

	2025	2024	(Unfavorable) Favorable Variance
Operating revenues	$ 7,267	$ 8,219	$ (952)
Operating expenses			
Purchased power	1,782	3,042	1,260
Operating and maintenance	1,710	1,703	(7)
Depreciation and amortization	1,560	1,514	(46)
Taxes other than income taxes	409	376	(33)
Total operating expenses	5,461	6,635	1,174
Gain on sales of assets	—	5	(5)
Operating income	1,806	1,589	217
Other income and (deductions)			
Interest expense, net	(530)	(501)	(29)
Other, net	132	94	38
Total other income and (deductions)	(398)	(407)	9
Income before income taxes	1,408	1,182	226
Income taxes	261	116	(145)
Net income	$ 1,147	$ 1,066	$ 81

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. **Net income** increased by $81 million primarily due to higher distribution and transmission rate base driven by incremental investments to serve customers, higher return on regulatory assets due to an increase in asset balances, and higher AFUDC, partially offset by lower transmission peak load.

The changes in **Operating revenues** consisted of the following:

	2025 vs. 2024 Increase (Decrease)
Distribution	$ 297
Transmission	—
Energy efficiency	32
Other	(47)
	282
Regulatory required programs	(1,234)
Total decrease	$ (952)

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. Operating revenues are not intended to be impacted by abnormal weather, usage per customer, or number of customers as a result of revenue decoupling mechanisms.

Distribution Revenue. Starting in 2024, distribution revenues are under a MRP. The MRP requires an annual reconciliation of the revenue requirement in effect to the actual costs the ICC determines are prudently and reasonably incurred. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, (e.g., severe weather and storm restoration), investments being recovered, and allowed ROE. Electric distribution revenue increased during the year ended December 31, 2025, compared to the same period in 2024, primarily due to higher fully recoverable costs, higher rate base, and higher return on regulatory assets.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, and the highest daily peak load, which is updated annually in January based on the prior calendar year. Transmission revenue for the year ended December 31, 2025, compared to the same period in 2024, remained relatively consistent.

Energy Efficiency Revenue. Energy efficiency revenues are under a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs the ICC determines are prudently and reasonably incurred in a given year. Energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. Energy efficiency revenue increased during the year ended December 31, 2025, compared to the same period in 2024, primarily due to increased regulatory asset amortization, which is fully recoverable.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. Other revenue decreased for the year ended December 31, 2025, compared to the same period in 2024, which primarily reflects decreased mutual assistance revenues associated with storm restoration efforts.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as recoveries under the credit loss expense tariff, environmental costs associated with MGP sites, ETAC, and costs related to electricity, ZEC, CMC, and REC procurement. ETAC is a retail customer surcharge collected and remitted to an Illinois state agency for programs to support clean energy jobs and training. The riders are designed to provide full and current cost recovery. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries as ComEd remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ComEd either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ComEd, ComEd is permitted to recover the electricity, ZEC, CMC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, CMCs, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The $1,260 million decrease in **Purchased power expense** for the year ended December 31, 2025 compared to the same period in 2024, which includes the impacts of CMC nuclear production tax credits, is offset in Operating revenues as part of regulatory required programs. See Note 2 — Regulatory Matters for additional information.

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

		2025 vs. 2024
		(Decrease) Increase
Labor, other benefits, contracting, and materials	$	(9)
BSC costs		(14)
Pension and non-pension postretirement benefits expense		5
Storm-related costs		2
		(15)
Regulatory required programs[a]		22
Total increase	$	7

(a) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism.

The changes in **Depreciation and amortization expense** consisted of the following:

		2025 vs. 2024
		Increase (Decrease)
Depreciation and amortization[a]	$	56
Regulatory asset amortization[b]		(10)
Total increase	$	46

(a) Reflects ongoing capital expenditures.
(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Interest expense, net increased $29 million for the year ended December 31, 2025, compared to the same period in 2024, primarily due to an increase in interest rates and the issuance of debt in 2025.

Other, **net** increased $38 million for the year ended December 31, 2025, compared to the same period in 2024, primarily due to higher AFUDC equity.

Effective income tax rates were 18.5% and 9.8% for the years ended December 31, 2025 and 2024, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—PECO

	2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 4,684	$ 3,973	$ 711
Operating expenses			
Purchased power and fuel	1,733	1,477	(256)
Operating and maintenance	1,195	1,120	(75)
Depreciation and amortization	454	428	(26)
Taxes other than income taxes	240	218	(22)
Total operating expenses	3,622	3,243	(379)
Gain on sales of assets	—	4	(4)
Operating income	1,062	734	328
Other income and (deductions)			
Interest expense, net	(260)	(232)	(28)
Other, net	41	37	4
Total other income and (deductions)	(219)	(195)	(24)
Income before income taxes	843	539	304
Income taxes	29	(12)	(41)
Net income	$ 814	$ 551	$ 263

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. **Net income** increased by $263 million due to an increase in revenue as a result of electric and gas distribution rates, favorable weather relative to the same period last year, and tax repairs related to storms, partially offset by an increase in contracting, depreciation and interest expense.

The changes in **Operating revenues** consisted of the following:

	2025 vs. 2024		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 27	$ 32	$ 59
Volume	(27)	2	(25)
Pricing	321	91	412
Transmission	4	—	4
Other	10	2	12
	335	127	462
Regulatory required programs	168	81	249
Total increase	$ 503	$ 208	$ 711

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. For the year ended December 31, 2025, compared to the same period in 2024, Operating revenues related to weather increased due to favorable weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO’s service territory. The changes in heating and cooling degree days in PECO’s service territory for the year ended December 31, 2025, compared to the same period in 2024, and normal weather consisted of the following:

PECO Service Territory	For the Years Ended December 31, 2025	2024	Normal	% Change 2025 vs. 2024	2025 vs. Normal
Heating Degree-Days	4,274	3,786	4,348	12.9 %	(1.7)%
Cooling Degree-Days	1,547	1,652	1,455	(6.4)%	6.3 %

Volume. Electric volume, exclusive of the effects of weather, for the year ended December 31, 2025, compared to the same period in 2024, decreased due to customer load. Natural gas volume for the year ended December 31, 2025, compared to the same period in 2024, remained relatively consistent.

Electric Retail Deliveries to Customers (in GWhs)	2025	2024	% Change	Weather - Normal % Change[b]
Residential	14,078	13,963	0.8 %	(1.5)%
Small commercial & industrial	7,537	7,683	(1.9)%	(3.0)%
Large commercial & industrial	13,683	13,889	(1.5)%	(2.2)%
Public authorities & electric railroads	678	613	10.6 %	11.0 %
Total electric retail deliveries[a]	35,976	36,148	(0.5)%	(1.9)%

Number of Electric Customers	At December 31, 2025	2024
Residential	1,541,970	1,533,443
Small commercial & industrial	154,841	155,164
Large commercial & industrial	3,158	3,150
Public authorities & electric railroads	10,248	10,708
Total	1,710,217	1,702,465

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Natural Gas Deliveries to Customers (in mmcf)	2025	2024	% Change	Weather - Normal % Change[b]
Residential	43,189	38,328	12.7 %	1.6 %
Small commercial & industrial	23,709	21,906	8.2 %	0.6 %
Large commercial & industrial	15	17	(11.8)%	(2.2)%
Transportation	24,204	23,357	3.6 %	0.7 %
Total natural gas deliveries[a]	91,117	83,608	9.0 %	1.1 %

Number of Natural Gas Customers	At December 31, 2025	2024
Residential	510,959	508,224
Small commercial & industrial	44,698	44,846
Large commercial & industrial	7	7
Transportation	617	644
Total	556,281	553,721

(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Pricing for the year ended December 31, 2025, compared to the same period in 2024, increased primarily due to electric and gas distribution rates charged to customers.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue for the year ended December 31, 2025, compared to the same period in 2024, remained relatively consistent.

Other Revenue primarily includes revenue related to late payment charges. Other revenues for the year ended December 31, 2025, compared to the same period in 2024, increased primarily due to revenue related to late payment charges.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, TSC, and the GSA. The riders are designed to provide full and current cost recovery, and in some cases, a return. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as PECO remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, PECO either acts as the billing agent or the competitive supplier separately bills its own customers and therefore PECO does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from PECO, PECO is permitted to recover the electricity, natural gas, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power and fuel expense related to the electricity, natural gas, and RECs.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of $256 million for the year ended December 31, 2025, compared to the same period in 2024, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2025 vs. 2024 Increase (Decrease)
Labor, other benefits, contracting, and materials	$ 51
Credit loss expense	8
Pension and non-pension postretirement benefits expense	4
Storm-related costs	3
BSC costs	2
Other	22
	90
Regulatory required programs	(15)
Total increase	$ 75

The changes in **Depreciation and amortization expense** consisted of the following:

	2025 vs. 2024 Increase (Decrease)
Depreciation and amortization[(a)]	$ 37
Regulatory asset amortization	(11)
Total increase	$ 26

(a) Depreciation and amortization expense increased primarily due to ongoing capital expenditures.

Taxes other than income taxes increased by $22 million for the year ended December 31, 2025, compared to the same period in 2024, primarily due to higher Pennsylvania gross receipts tax.

Interest expense, net increased $28 million for the year ended December 31, 2025, compared to the same period in 2024, primarily due to an increase in interest rates and the issuance of debt in 2025.

Effective income tax rates were 3.4% and (2.2)% for the years ended December 31, 2025 and 2024, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—BGE

	2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 5,222	$ 4,426	$ 796
Operating expenses			
Purchased power and fuel	2,221	1,651	(570)
Operating and maintenance	1,066	1036	(30)
Depreciation and amortization	632	638	6
Taxes other than income taxes	370	345	(25)
Total operating expenses	4,289	3,670	(619)
Operating income	933	756	177
Other income and (deductions)			
Interest expense, net	(247)	(216)	(31)
Other, net	51	36	15
Total other income and (deductions)	(196)	(180)	(16)
Income before income taxes	737	576	161
Income taxes	159	49	(110)
Net income	$ 578	$ 527	$ 51

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. **Net income** increased $51 million primarily due to distribution rates, favorable impacts of the multi-year plan reconciliation and a decrease in storm costs, partially offset by an increase in interest expense and the derecognition of regulatory assets and liabilities for multi-year plan reconciliations that will no longer be filed as a result of the Next Generation Energy Act. See Note 2 — Regulatory Matters for additional information on the multi-year plan reconciliation and the Next Generation Energy Act.

The changes in **Operating revenues** consisted of the following:

	2025 vs. 2024		
	Increase		
	Electric	Gas	Total
Distribution	$ 82	$ 62	$ 144
Transmission	6	—	6
Other	11	—	11
	99	62	161
Regulatory required programs	471	164	635
Total increase	$ 570	$ 226	$ 796

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and customer usage. However, Operating revenues are not impacted by abnormal weather or usage per customer as a result of a monthly rate adjustment that provides for fixed distribution revenue per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling.

	At December 31,	
Number of Electric Customers	**2025**	**2024**
Residential	1,222,397	1,216,614
Small commercial & industrial	115,197	115,010
Large commercial & industrial	13,445	13,266
Public authorities & electric railroads	252	260
Total	1,351,291	1,345,150

	At December 31,	
Number of Natural Gas Customers	**2025**	**2024**
Residential	660,986	658,776
Small commercial & industrial	37,759	37,874
Large commercial & industrial	6,417	6,369
Total	705,162	703,019

Distribution Revenue increased for the year ended December 31, 2025 compared to the same period in 2024, due to favorable impacts of the multi-year plans.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the year ended December 31, 2025 compared to the same period in 2024 primarily due to increases in underlying costs and capital investments.

Other Revenue includes revenue related to late payment charges, mutual assistance, off-system sales, and service application fees. Other Revenue increased for the year ended December 31, 2025 compared to the same period in 2024, primarily driven by an increase in service application fees.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, and the POLR mechanism. The riders are designed to provide full and current cost recovery, as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries as BGE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, BGE acts as the billing agent and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from BGE, BGE is permitted to recover the electricity and natural gas procurement costs from customers and therefore records the amounts related to the electricity and/or natural gas in Operating revenues and Purchased power and fuel expense. BGE recovers electricity and natural gas procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The increase of $570 million for the year ended December 31, 2025 compared to the same period in 2024 in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2025 vs. 2024	
	Increase (Decrease)	
BSC costs	$	5
Credit loss expense		1
Labor, other benefits, contracting, and materials		1
Multi-year plan reconciliation[a]		(9)
Storm-related costs		(13)
Other[b]		5
		(10)
Regulatory required programs[c]		40
Total increase	$	30

(a) See Note 2 — Regulatory Matters for additional information on the multi-year plan reconciliation.
(b) Reflects the derecognition of regulatory assets for multi-year plan reconciliations that will no longer be filed as a result of the Next Generation Energy Act, partially offset by the absence of capital write-offs included in 2024. See Note 2 — Regulatory Matters for additional information regarding the Next Generation Energy Act.
(c) Reflects the cost recovery associated with EmPOWER Maryland. See Note 2 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	2025 vs. 2024	
	Increase (Decrease)	
Depreciation and amortization	$	13
Regulatory required programs[a]		21
Regulatory asset amortization		(40)
Total decrease	$	(6)

(a) Reflects the cost recovery associated with EmPOWER Maryland. See Note 2 — Regulatory Matters for additional information.

Taxes other than income taxes increased by $25 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to increased property taxes.

Interest expense, net increased $31 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to the issuance of debt in the second quarter of 2025.

Other, net increased by $15 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to increased interest income and higher AFUDC equity.

Effective income tax rates were 21.6% and 8.5% for the years ended December 31, 2025 and 2024, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—PHI

PHI's Results of Operations include the results of its three reportable segments, Pepco, DPL, and ACE. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services and the costs are directly charged or allocated to the applicable subsidiaries. Additionally, the results of PHI's corporate operations include interest costs from various financing activities. All material intercompany accounts and transactions have been eliminated in consolidation. The following table sets forth PHI's GAAP consolidated Net income, by Registrant, for the year ended December 31, 2025 compared to the same period in 2024. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	2025	2024	Favorable Variance
PHI	$ 799	$ 741	$ 58
Pepco	401	390	11
DPL	224	209	15
ACE	188	155	33
Other[a]	(14)	(14)	—

(a) Primarily includes eliminating and consolidating adjustments, PHI's corporate operations, shared service entities, and other financing and investing activities.

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. **Net income** increased by $58 million primarily due to electric distribution rates, favorable impacts of the ACE Electric Distribution Base Rate Case, including the recognition of the regulatory asset and corresponding decrease in O&M associated with work stoppage costs that were incurred by ACE in 2023, DPL Delaware electric DSIC rates and natural gas rates, and transmission rates, partially offset by the absence of the Pepco Maryland multi-year plans reconciliations, lower AFUDC income, and increases in interest expense, depreciation expense and contracting costs.

Results of Operations—Pepco

	2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 3,454	$ 3,039	$ 415
Operating expenses			
Purchased power	1,262	1,055	(207)
Operating and maintenance	625	534	(91)
Depreciation and amortization	433	407	(26)
Taxes other than income taxes	455	424	(31)
Total operating expenses	2,775	2,420	(355)
(Loss) gain on sales of assets	1	(1)	2
Operating income	680	618	62
Other income and (deductions)			
Interest expense, net	(214)	(192)	(22)
Other, net	41	54	(13)
Total other income and (deductions)	(173)	(138)	(35)
Income before income taxes	507	480	27
Income taxes	106	90	(16)
Net income	$ 401	$ 390	$ 11

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. **Net income** increased by $11 million primarily due to distribution and transmission rates, partially offset by the absence of the Maryland multi-year plans reconciliations, lower AFUDC income, and increases in interest expense and depreciation expense.

The changes in **Operating revenues** consisted of the following:

	2025 vs. 2024 Increase (Decrease)
Distribution	$ 135
Transmission	27
Other	(9)
	153
Regulatory required programs	262
Total increase	$ 415

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in both Maryland and the District of Columbia are not intended to be impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer class in the District of Columbia and per customer by customer class in Maryland. Therefore, changes in the number of customers only impacts Operating revenues in Maryland. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling Pepco Maryland.

Number of Electric Customers in Maryland	At December 31, 2025	2024
Residential	560,304	556,239
Small commercial & industrial	30,548	30,571
Large commercial & industrial	19,078	18,989
Public authorities & electric railroads	179	179
Total	610,109	605,978

Distribution Revenue increased for the year ended December 31, 2025 compared to the same period in 2024, primarily due to the favorable impacts of the Maryland and District of Columbia multi-year plans and customer growth in Maryland.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the year ended December 31, 2025 compared to the same period in 2024 primarily due to increases in underlying costs and capital investment.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG, and SOS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as Pepco remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, Pepco acts as the billing agent and therefore, Pepco does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from Pepco, Pepco is permitted to recover the electricity and REC procurement costs from customers and therefore records the amounts related to the electricity and RECs in Operating revenues and Purchased power expense. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The increase of $207 million for the year ended December 31, 2025 compared to the same period in 2024, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2025 vs. 2024 Increase (Decrease)
Labor, other benefits, contracting, and materials	$ 26
Maryland multi-year plan reconciliations [(a)]	23
Credit loss expense	2
Pension and non-pension postretirement benefits expense	1
Storm-related costs	1
BSC and PHISCO costs	(5)
Other	7
	55
Regulatory required programs [(b)]	36
Total increase	$ 91

(a) See Note 2 — Regulatory Matters for additional information on multi-year plan reconciliations.
(b) Reflects the cost recovery associated with EmPOWER Maryland. Please refer to Note 2 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	2025 vs. 2024 Increase (Decrease)
Depreciation and amortization[(a)]	$ 24
Regulatory asset amortization	6
Regulatory required programs[(b)]	(4)
Total increase	$ 26

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.
(b) Reflects the cost recovery associated with EmPOWER Maryland. Please refer to Note 2 — Regulatory Matters for additional information.

Taxes other than income taxes increased $31 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to increases in utility taxes, which are offset in revenues, and property taxes.

Interest expense, net increased $22 million for the year ended December 31, 2025 compared to the same period in 2024 primarily due to an increase in interest rates and the issuance of debt in 2025.

Other, **net** decreased $13 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to lower AFUDC equity.

Effective income tax rates were 20.9% and 18.8% for the years ended December 31, 2025 and 2024, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—DPL

	2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 1,971	$ 1,787	$ 184
Operating expenses			
Purchased power and fuel	861	760	(101)
Operating and maintenance	391	377	(14)
Depreciation and amortization	252	245	(7)
Taxes other than income taxes	88	79	(9)
Total operating expenses	1,592	1,461	(131)
Operating income	379	326	53
Other income and (deductions)			
Interest expense, net	(102)	(93)	(9)
Other, net	16	25	(9)
Total other income and (deductions)	(86)	(68)	(18)
Income before income taxes	293	258	35
Income taxes	69	49	(20)
Net income	$ 224	$ 209	$ 15

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. Net income increased by $15 million primarily due to Delaware electric DSIC and natural gas rates, favorable weather conditions at Delaware electric and natural gas service territories, and transmission rates, partially offset by increases in interest and depreciation expense.

The changes in **Operating revenues** consisted of the following:

	2025 vs. 2024		
	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 8	$ 3	$ 11
Volume	(4)	7	3
Distribution	20	14	34
Transmission	19	—	19
Other	(1)	—	(1)
	42	24	66
Regulatory required programs	90	28	118
Total increase	$ 132	$ 52	$ 184

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in Maryland are not intended to be impacted by abnormal weather or usage per customer as a result of a BSA that provides for a fixed distribution charge per customer by customer class. While Operating revenues from electric distribution customers in Maryland are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling for DPL Maryland.

Weather. The demand for electricity and natural gas in Delaware is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the year ended December 31, 2025 compared to the same period in 2024, Operating revenues related to weather increased due to favorable weather conditions in DPL's Delaware electric and natural gas service territories.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's Delaware electric service territory and a 30-year period in DPL's Delaware natural gas service territory. The changes in heating and cooling degree days in DPL’s Delaware service territory for the year ended December 31, 2025 compared to same period in 2024 and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Delaware Electric Service Territory	**2025**	**2024**	**Normal**	**2025 vs. 2024**	**2025 vs. Normal**
Heating Degree-Days	4,500	4,100	4,477	9.8 %	0.5 %
Cooling Degree-Days	1,309	1,277	1,302	2.5 %	0.5 %

	For the Years Ended December 31,			% Change	
Delaware Natural Gas Service Territory	**2025**	**2024**	**Normal**	**2025 vs. 2024**	**2025 vs. Normal**
Heating Degree-Days	4,500	4,100	4,605	9.8 %	(2.3)%

Volume, exclusive of the effects of weather, increased for the year ended December 31, 2025 compared to the same period in 2024 primarily due to an increase in customer growth.

Electric Retail Deliveries to Delaware Customers (in GWhs)	**2025**	**2024**	**% Change**	**Weather - Normal % Change [(b)]**
Residential	3,288	3,227	1.9 %	(1.4)%
Small commercial & industrial	1,459	1,445	1.0 %	0.2 %
Large commercial & industrial	3,049	3,019	1.0 %	0.6 %
Public authorities & electric railroads	31	32	(3.1)%	(3.5)%
Total electric retail deliveries[(a)]	7,827	7,723	1.3 %	(0.3)%

	At December 31,	
Number of Total Electric Customers (Maryland and Delaware)	**2025**	**2024**
Residential	495,254	490,626
Small commercial & industrial	65,500	64,813
Large commercial & industrial	1,273	1,255
Public authorities & electric railroads	634	606
Total	562,661	557,300

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(a) Reflects delivery volumes from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 20-year average.

Natural Gas Retail Deliveries to Delaware Customers (in mmcf)	**2025**	**2024**	**% Change**	**Weather - Normal % Change[(b)]**
Residential	9,052	7,810	15.9 %	7.5 %
Small commercial & industrial	4,339	3,801	14.2 %	5.5 %
Large commercial & industrial	1,680	1,674	0.4 %	0.4 %
Transportation	6,355	6,206	2.4 %	(0.3)%
Total natural gas deliveries[(a)]	21,426	19,491	9.9 %	4.1 %

Number of Delaware Natural Gas Customers	At December 31, 2025	2024
Residential	132,148	131,392
Small commercial & industrial	10,255	10,218
Large commercial & industrial	14	14
Transportation	160	162
Total	142,577	141,786

(a) Reflects delivery volumes from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.
(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Distribution Revenue increased for the year ended December 31, 2025 compared to the same period in 2024 primarily due to Delaware electric DSIC rates and natural gas rates that became effective in 2025.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue increased for the year ended December 31, 2025 compared to the same period in 2024 primarily due to increases in underlying costs and capital investment.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DE Renewable Portfolio Standards, SOS procurement and administrative costs, and GCR costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power and fuel expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. All customers have the choice to purchase electricity from competitive electric generation suppliers; however, only certain commercial and industrial customers have the choice to purchase natural gas from competitive natural gas suppliers. Customer choice programs do not impact the volume of deliveries as DPL remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation or natural gas from competitive suppliers, DPL either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore does not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from DPL, DPL is permitted to recover the electricity, natural gas, and REC procurement costs from customers and therefore records the amounts related to the electricity, natural gas, and RECs in Operating revenues and Purchased power and fuel expense. DPL recovers electricity and REC procurement costs from customers with a slight mark-up, and natural gas costs without mark-up.

See Note 4 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The increase of $101 million for the year ended December 31, 2025 compared to the same period in 2024, in **Purchased power and fuel expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2025 vs. 2024 Increase (Decrease)
Credit loss expense	$ 3
Pension and non-pension postretirement benefits expense	1
Labor, other benefits, contracting, and materials	(2)
BSC and PHISCO costs	(5)
Storm-related costs	(5)
Other	3
	$ (5)
Regulatory required programs[(a)]	19
Total increase	$ 14

(a) Reflects the cost recovery associated with EmPOWER Maryland. Please refer to Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	2025 vs. 2024 Increase (Decrease)
Depreciation and amortization[(a)]	$ 8
Regulatory asset amortization	(1)
Total increase	$ 7

(a) Depreciation and amortization increased primarily due to ongoing expenditures.

Taxes other than income taxes increased by $9 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to an increase in property taxes.

Interest expense, net increased $9 million for the year ended December 31, 2025 compared to the same period in 2024 primarily due to an increase in interest rates and the issuance of debt in 2025.

Other, net decreased by $9 million for the year ended December 31, 2025 compared to the same period in 2024, primarily due to lower AFUDC equity and a decrease in interest income.

Effective income tax rates were 23.5% and 19.0% for the years ended December 31, 2025 and 2024, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

Results of Operations—ACE

	2025	2024	Favorable (Unfavorable) Variance
Operating revenues	$ 1,718	$ 1,628	$ 90
Operating expenses			
Purchased power	808	698	(110)
Operating and maintenance	328	368	40
Depreciation and amortization	248	278	30
Taxes other than income taxes	9	9	—
Total operating expenses	1,393	1,353	(40)
Gain on sale of assets	2	—	2
Operating income	327	275	52
Other income and (deductions)			
Interest expense, net	(82)	(79)	(3)
Other, net	10	14	(4)
Total other income and (deductions)	(72)	(65)	(7)
Income before income taxes	255	210	45
Income taxes	67	55	(12)
Net income	$ 188	$ 155	$ 33

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024. Net income increased by $33 million primarily due to favorable impacts of the ACE Electric Distribution Base Rate Case, including the recognition of the regulatory asset and corresponding decrease in O&M associated with work stoppage costs that were incurred by ACE in 2023, a decrease in various operating expenses, distribution rates and an increase in customer growth, offset by an increase in interest and depreciation expense.

The changes in Operating revenues consisted of the following:

	2025 vs. 2024
	Increase
Distribution	$ 6
Other	3
	9
Regulatory required programs	81
Total increase	$ 90

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in New Jersey are not intended to be impacted by abnormal weather or usage per customer as a result of the CIP which compares current distribution revenues by customer class to approved target revenues established in ACE's most recent distribution base rate case. The CIP is calculated annually, and recovery is subject to certain conditions, including an earnings test and ceilings on customer rate increases. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 2 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information on the ACE CIP.

Number of Electric Customers	At December 31, 2025	2024
Residential	510,005	507,483
Small commercial & industrial	63,154	62,739
Large commercial & industrial	2,682	2,843
Public authorities & electric railroads	754	714
Total	576,595	573,779

Distribution Revenue increased for the year ended December 31, 2025 compared to the same period in 2024 primarily due to distribution rates and an increase in customer growth.

Transmission Revenue. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs and capital investments being recovered. Transmission revenue remained relatively consistent for the year ended December 31, 2025 compared to the same period in 2024.

Other Revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bonds, and BGS procurement and administrative costs. The riders are designed to provide full and current cost recovery as well as a return in certain instances. The costs of these programs are included in Purchased power expense, Operating and maintenance expense, Depreciation and amortization expense, and Taxes other than income taxes. Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries, as ACE remains the distribution service provider for all customers and charges a regulated rate for distribution service, which is recorded in Operating revenues. For customers that choose to purchase electric generation from competitive suppliers, ACE acts as the billing agent and therefore, ACE does not record Operating revenues or Purchased power expense related to the electricity. For customers that choose to purchase electric generation from ACE, ACE is permitted to recover the electricity, ZEC, and REC procurement costs without mark-up and therefore records equal and offsetting amounts in Operating revenues and Purchased power expense related to the electricity, ZECs, and RECs.

See Note 4 – Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The increase of $110 million for the year ended December 31, 2025 compared to same period in 2024, in **Purchased power expense** is fully offset in Operating revenues as part of regulatory required programs.

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

	2025 vs. 2024 Increase (Decrease)
Storm-related costs	$ 3
BSC and PHISCO costs	(10)
Labor, other benefits, contracting and materials[(a)]	(33)
Other	(1)
	(41)
Regulatory required programs	1
Total decrease	$ (40)

(a) Reflects a decrease in contracting costs for the year ended December 31, 2025, resulting from the favorable impacts of the ACE Electric Distribution Base Rate Case, including the recognition of the regulatory asset and corresponding decrease in O&M associated with work stoppage costs that were incurred by ACE in 2023. See Note 2 — Regulatory Matters for additional information.

The changes in **Depreciation and amortization expense** consisted of the following:

	2025 vs. 2024	
	Increase (Decrease)	
Depreciation and amortization[a]	$	12
Regulatory asset amortization		(11)
Regulatory required programs[b]		(31)
Total decrease	$	(30)

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures.
(b) Regulatory required programs decreased primarily due to the absence of the regulatory asset amortization of the PPA termination obligation, which was fully amortized in 2024.

Interest expense, net increased $3 million for the year ended December 31, 2025 compared to the same period in 2024 primarily due to an increase in interest rates and the issuance of debt in 2025.

Effective income tax rates were 26.3% and 26.2% for the years ended December 31, 2025 and 2024, respectively. See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Liquidity and Capital Resources

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

The Registrants' operating and capital expenditure 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. The Registrants' businesses are capital intensive and require considerable capital resources. Each of the Registrants annually evaluates its financing plan, dividend practices, and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, including construction expenditures, retire debt, pay dividends, and fund pension and OPEB obligations. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, the Utility Registrants operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to credit facilities with aggregate bank commitments of $4 billion, as of December 31, 2025. The Registrants utilize their credit facilities to support their 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. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE, and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, and their ability to achieve operating cost reductions. Additionally, ComEd is required to purchase CMCs from participating nuclear-powered generating facilities for a five-year period, and all of its costs of doing so is recovered through a rider. The price to be paid for each CMC is established through a competitive bidding process. ComEd will provide net payments to, or collect net payments from, customers for the difference between customer credits issued and the credit to be received from the participating nuclear-powered generating facilities. ComEd's cash flows are affected by the establishment of CMC prices and the timing of recovering costs through the CMC regulatory liability.

See Note 2 — Regulatory Matters and Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the years ended December 31, 2025 and 2024 by Registrant:

Increase (decrease) in cash flows from operating activities	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Net income (loss)	$ 308	$ 81	$ 263	$ 51	$ 58	$ 11	$ 15	$ 33
Adjustments to reconcile net income to cash:								
Non-cash operating activities	1,058	617	43	207	98	131	40	(56)
Collateral (paid) received, net	(43)	(66)	6	5	17	12	—	5
Income taxes	125	113	359	223	26	(3)	40	14
Pension and non-pension postretirement benefit contributions	(162)	(184)	(9)	(7)	36	—	2	5
Regulatory assets and liabilities, net	206	260	(60)	(13)	31	(8)	16	26
Changes in working capital and other noncurrent assets and liabilities	(807)	(869)	47	(132)	(78)	(102)	(35)	74
Increase (decrease) in cash flows from operating activities	$ 685	$ (48)	$ 649	$ 334	$ 188	$ 41	$ 78	$ 101

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant’s respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. Significant operating cash flow impacts for the Registrants for the years ended December 31, 2025 and 2024 were as follows:

- See Note 20 —Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements and the Registrants’ Consolidated Statements of Cash Flows for additional information on **non-cash operating activities**.

- **Changes in collateral** depended upon whether the Registrant was in a net mark-to-market liability or asset position and whether collateral may have been required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differed depending on whether the transactions were on an exchange or in the over-the-counter markets. Changes in collateral for the Utility Registrants are dependent upon the credit exposure of procurement contracts that may require suppliers to post collateral. The amount of cash collateral received from external counterparties remained relatively consistent due to stable energy prices. See Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

- See Note 11 — Income Taxes of the Combined Notes to Consolidated Financial Statements and the Registrants' Consolidated Statements of Cash Flows for additional information on **income taxes.**

- Changes in **Pension and non-pension postretirement benefit contributions** relate to Exelon's increased contributions to the Qualified Plans during the year ended December 31, 2025. See Note 14 — Retirement Benefits

- **Changes in Regulatory assets and liabilities, net,** are due to the timing of cash payments for costs recoverable, or cash receipts for costs recovered, under our regulatory mechanisms differing from the recovery period of those costs. ComEd recognized changes of $849 million and $493 million related to carbon mitigation credits for the years ended December 31, 2025 and 2024, respectively. Included within the change in 2025 is an $804 million adjustment for CMC nuclear production tax credits, which is offset by an increase in Accounts receivable. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. ComEd's energy efficiency program recognized changes of $447 million and $435 million for the years ended December 31, 2025 and 2024, respectively. Additionally, ComEd recognized changes in the distributed generation rebates program of $83 million and $74 million for the years ended December 31, 2025 and 2024, respectively. Also included within the changes is energy efficiency and demand response programs spend for BGE, Pepco, DPL, and ACE of $85 million, $41 million, $16 million, and $55 million for the year ended December 31, 2025, respectively, and $127 million, $52 million, $21 million, and $37 million for the year ended December 31, 2024, respectively. PECO had no energy efficiency and demand response programs spend recorded to a regulatory asset for the years ended December 31, 2025 and 2024.

- **Changes in working capital and other noncurrent assets and liabilities** for the Utility Registrants and Exelon Corporate total $(1,017) million and $(807) million. The change in working capital and other noncurrent assets and liabilities for Exelon Corporate and the Utility Registrants is dependent upon the normal course of operations for all Registrants. For ComEd, it is also dependent upon whether the participating nuclear-powered generating facilities owe money to ComEd as a result of the established pricing for CMCs. For the year ended December 31, 2025, the established pricing resulted in nuclear-powered generating facilities owing payments to ComEd primarily due to $804 million of nuclear production tax credits, which is reported within the cash flows from operations as a change in Accounts receivable. This change is offset by an increase in the Carbon mitigation credit regulatory liability. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Cash Flows from Investing Activities

The following table provides a summary of the change in cash flows from investing activities for the years ended December 31, 2025 and 2024 by Registrant:

(Decrease) increase in cash flows from investing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ (1,432)	$ (704)	$ (314)	$ (237)	$ (193)	$ (28)	$ 22	$ (17)
Proceeds from sales of assets	(34)	—	—	—	4	2	—	2
Other investing activities	(17)	(1)	(3)	(3)	—	—	—	—
(Decrease) increase in cash flows from investing activities	$ (1,483)	$ (705)	$ (317)	$ (240)	$ (189)	$ (26)	$ 22	$ (15)

Significant investing cash flow impacts for the Registrants for 2025 and 2024 were as follows:

- Variances in **Capital expenditures** are primarily due to the timing of cash expenditures for capital projects. See the "Credit Matters and Cash Requirements" section below for additional information on projected capital expenditure spending for the Registrants.

Cash Flows from Financing Activities

The following table provides a summary of the change in cash flows from financing activities for the years ended December 31, 2025 and 2024 by Registrant:

Increase (decrease) in cash flows from financing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ (583)	$ 530	$ (219)	$ (14)	$ (54)	$ 35	$ (64)	$ (25)
Long-term debt, net	1,347	175	125	(150)	(17)	—	(17)	—
Changes in intercompany money pool	—	—	—	—	19	—	—	—
Issuance of common stock	543	—	—	—	—	—	—	—
Dividends paid on common stock	(93)	(37)	(146)	(25)	—	32	18	(56)
Distributions to member	—	—	—	—	(4)	—	—	—
Contributions from parent/member	—	164	(18)	294	63	(67)	(53)	13
Other financing activities	8	6	(3)	1	13	10	(2)	(1)
Increase (decrease) in cash flows from financing activities	$ 1,222	$ 838	$ (261)	$ 106	$ 20	$ 10	$ (118)	$ (69)

Significant financing cash flow impacts for the Registrants for 2025 and 2024 were as follows:

- **Changes in short-term borrowings, net**, is driven by repayments on and issuances of notes due in less than 365 days. Refer to Note 14 — Debt and Credit Agreements of the Combined Notes to

Consolidated Financial Statements for additional information on Short-term borrowings for the Registrants.

- **Long-term debt, net,** varies due to debt issuances and redemptions each year. Refer to the debt issuances and redemptions tables below for additional information for the Registrants.

- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer below for more information regarding the intercompany money pool.

- **Issuance of common stock** is driven by the issuance of Exelon common stock under the ATM program in 2025 compared to 2024. See Note 17 — Shareholders' Equity of the Combined Notes to Consolidated Financial Statements for additional information.

- Exelon’s ability to pay **dividends** on its Common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting Retained earnings. See Note 16 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on dividend restrictions. See below for quarterly dividends declared.

- **Other financing activities** primarily consists of debt issuance costs. See the debt issuances table below for additional information on the Registrants’ debt issuances.

Debt Issuances and Redemptions

See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' long-term debt. The Registrants' debt activities for 2025 and 2024 was as follows:

During 2025, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes[(a)]	6.50%	March 15, 2055	$1,000	Repay outstanding commercial paper obligations and for general corporate purposes.
Exelon	Notes	5.125%	March 15, 2031	500	Repay outstanding commercial paper obligations and for general corporate purposes.
Exelon	Notes	5.875%	March 15, 2055	500	Repay outstanding commercial paper obligations and for general corporate purposes.
Exelon	Convertible Senior Notes	3.25%	March 15, 2029	1,000	Repay or refinance debt and for general corporate purposes.
ComEd	First Mortgage Bonds	5.95%	June 1, 2055	725	Repay outstanding commercial paper obligations and for general corporate purposes.
PECO	First Mortgage Bonds	4.875%	September 15, 2035	525	Repay existing indebtedness, repay outstanding commercial paper obligations, and for general corporate purposes.
PECO	First Mortgage Bonds	5.65%	September 15, 2055	525	Repay existing indebtedness, repay outstanding commercial paper obligations, and for general corporate purposes.
BGE	Notes	5.45%	June 1, 2035	650	Repay outstanding commercial paper obligations and for general corporate purposes.
Pepco	First Mortgage Bonds	5.78%	September 17, 2055	75	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.48%	March 26, 2040	200	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.28%	March 26, 2035	125	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	5.28%	March 26, 2035	100	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	5.54%	November 19, 2040	75	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	5.81%	November 19, 2055	75	Repay existing indebtedness and for general corporate purposes.

(a) The Junior Subordinated Notes bear interest at 6.50% per annum, commencing February 19, 2025 to, but excluding March 15, 2035. Thereafter, the interest rate resets every five years on March 15 and will be set at a rate per annum equal to the Five-year U.S. Treasury Rate plus a spread of 1.975%.

During 2024, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Notes	5.15%	March 15, 2029	$650	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	5.45%	March 15, 2034	650	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	5.60%	March 15, 2053	400	Repay existing indebtedness and for general corporate purposes.
ComEd	First Mortgage Bonds	5.30%	June 1, 2034	400	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
ComEd	First Mortgage Bonds	5.65%	June 1, 2054	400	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
PECO	First Mortgage Bonds	5.25%	September 15, 2054	575	Refinance existing indebtedness, refinance outstanding commercial paper obligations, and for general corporate purposes.
BGE	Notes	5.30%	June 1, 2034	400	Repay outstanding commercial paper obligations, repay existing indebtedness, and for general corporate purposes.
BGE	Notes	5.65%	June 1, 2054	400	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.20%	March 15, 2034	375	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.50%	March 15, 2054	300	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.24%	March 20, 2034	100	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.55%	March 20, 2054	75	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.55%	March 20, 2054	75	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.29%	August 28, 2034	75	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.49%	August 28, 2039	100	Repay existing indebtedness and for general corporate purposes.

During 2025, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Senior Notes	3.95%	June 15, 2025	$ 807
Exelon	Software Licensing Agreement	2.30%	December 1, 2025	4
PECO	First Mortgage Bonds	3.15%	October 15, 2025	350
ACE	Senior Notes	3.50%	December 1, 2025	150

During 2024, the following long-term debt was retired and/or redeemed:

Company [a]	Type	Interest Rate	Maturity	Amount
Exelon	SMBC Term Loan Agreement	SOFR plus 0.85%	April 8, 2024	$ 500
Exelon	Software Licensing Agreement	3.62%	December 1, 2025	1
Exelon	Software Licensing Agreement	3.95%	May 1, 2024	2
Exelon	Software Licensing Agreement	2.30%	December 1, 2025	4
ComEd	First Mortgage Bonds	3.10%	November 1, 2024	250
Pepco	First Mortgage Bonds	3.60%	March 15, 2024	400
DPL[b]	Unsecured tax-exempt bonds	4.32%	July 1, 2024	33
ACE	First Mortgage Bonds	3.38%	September 1, 2024	150

(a) Exelon repurchased a portion of its Senior unsecured notes during 2024. Refer to Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Variable interest on the DPL unsecured tax-exempt bonds reset on a weekly basis.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective Balance sheets.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2025 and for the first quarter of 2026 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[a]
First Quarter 2025	February 12, 2025	February 24. 2025	March 14, 2025	$ 0.4000
Second Quarter 2025	April 29, 2025	May 12, 2025	June 13, 2025	$ 0.4000
Third Quarter 2025	July 29, 2025	August 11, 2025	September 15, 2025	$ 0.4000
Fourth Quarter 2025	October 29, 2025	November 10, 2025	December 15, 2025	$ 0.4000
First Quarter 2026	February 12, 2026	March 2, 2026	March 13, 2026	$ 0.4200

(a) Exelon's Board of Directors approved an updated dividend policy for 2026. The 2026 quarterly dividend will be $0.42 per share.

Credit Matters and Cash Requirements

The Registrants 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. The credit facilities include $4 billion in aggregate total commitments of which $3.3 billion was available to support additional commercial paper as of December 31, 2025, and of which no financial institution has more than 6.2% of the aggregate commitments for the Registrants. During 2025, the Registrants had access to the commercial paper markets and availability under their revolving credit facilities to fund their short-term liquidity needs, when necessary. Exelon Corporate and the Utility Registrants each have a 5-year revolving credit facility. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. The Registrants routinely review the sufficiency of their 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. The Registrants closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I, ITEM 1A. RISK FACTORS for additional information regarding the effects of uncertainty in the capital and credit markets.

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

On August 4, 2022, Exelon executed an equity distribution agreement (“2022 Equity Distribution Agreement”), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program under which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to $1 billion through August 3, 2025. On May 2, 2025, Exelon executed an additional equity distribution agreement ("2025 Equity Distribution Agreement" and, together with the August 4, 2022 Equity Distribution Agreement, "Equity Distribution Agreements"), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to $2.5 billion through May 2, 2028. The 2025 Equity Distribution Agreement replaced the 2022 Equity Distribution Agreement. Exelon has no obligation to offer or sell any shares of Common stock under the 2025 Equity Distribution Agreement and may, at any time, suspend or terminate offers and sales under the 2025 Equity Distribution Agreement. Exelon issued a total of 23.6 million shares of common stock with net proceeds of $979 million under these agreements in the years ended December 31, 2023 through December 31, 2025.

In addition, during the twelve months ended December 31, 2025, Exelon entered into various forward sale agreements under the 2025 ATM programs. The forward sale agreements require Exelon to, at its election prior to the maturity date, either (i) physically settle the transactions by issuing shares of its Common stock to the forward counterparties in exchange for net proceeds at the then-applicable forward sale price specified by the agreements or (ii) net settle the transactions in whole or in part through the delivery to the forward counterparties or receipt from the forward counterparties of cash or shares in accordance with the provisions of the agreements.

No amounts have been or will be recorded on Exelon's Balance sheets with respect to the equity offerings until the equity forward sale agreements have been settled. Each initial forward sale price is subject to adjustment on a daily basis based on a floating interest rate factor and will decrease by other fixed amounts specified in the agreements. Until settlement of the equity forward, earnings per share dilution resulting from the agreement, if any, will be determined under the treasury stock method. For the twelve months ended December 31, 2025, approximately 15.4 million shares under the forward sale agreements were not included in the calculation of diluted earnings per share because their effect would have been antidilutive.

Inclusive of the impact of the forward sale agreements, $1.5 billion of Common stock remained available for sale pursuant to the ATM program as of December 31, 2025.

See Note 17 — Shareholders' Equity of the Combined Notes to the Consolidated Financial Statements for additional information regarding ATM program terms, forward sale agreements, and share-level activity.

The following table presents the incremental collateral that each Utility Registrant would have been required to provide in the event each Utility Registrant lost its investment grade credit rating at December 31, 2025 and available credit facility capacity prior to any incremental collateral at December 31, 2025:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 27	$ —	$ 985
PECO	—	58	595
BGE	—	43	575
Pepco	4	—	55
DPL	1	14	139
ACE	—	—	92

(a) Represents incremental collateral related to natural gas procurement contracts.

Capital Expenditures

As of December 31, 2025, estimates of future capital expenditures for plant additions and improvements were as follows:

(in millions)[(a)]	2026 Transmission	2026 Distribution	2026 Gas	Total 2026	Beyond 2026[(b)]
Exelon	N/A	N/A	N/A	$ 9,950	$ 31,300
ComEd	1,100	2,425	N/A	3,500	11,450
PECO	450	1,375	400	2,225	7,075
BGE	1,075	575	525	2,175	6,100
PHI	725	1,250	50	2,050	6,650
Pepco	325	650	N/A	975	2,925
DPL	225	325	50	625	2,175
ACE	175	275	N/A	450	1,550

(a) Numbers rounded to the nearest $25M and may not sum due to rounding.
(b) Includes estimated capital expenditures for the Utility Registrants from 2027 to 2029.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors. Projected capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems. The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent.

Retirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy to make annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This funding strategy helps minimize volatility of future period required pension contributions. Exelon’s estimated annual qualified pension contributions will be $325 million in 2026. Unlike the qualified pension plans, Exelon’s non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon’s management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.

The following table provides all Registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2026:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 325	$ 19	$ 48
ComEd	217	3	22
PECO	9	1	4
BGE	32	2	14
PHI	48	7	6
Pepco	1	—	6
DPL	1	—	—
ACE	14	—	—

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

See Note 12 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information on pension and OPEB contributions.

Cash Requirements for Other Financial Commitments

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2025 under existing financial commitments:

Exelon

	2026	Beyond 2026	Total	Time Period
Long-term debt and finance leases[a]	$ 1,665	$ 47,763	$ 49,428	2026 - 2055
Interest payments on long-term debt[b]	1,932	31,796	33,728	2026 - 2055
Operating leases	26	187	213	2026 - 2099
Fuel purchase agreements[c]	321	1,293	1,614	2026 - 2039
Electric supply procurement	4,259	2,733	6,992	2026 - 2029
Long-term renewable energy and REC commitments	290	7,716	8,006	2026 - 2044
ZEC commitments	156	62	218	2026 - 2027
Pension contributions[d]	325	1,625	1,950	2026 - 2031
Other purchase obligations[e]	9,526	5,303	14,829	2026 - 2035
Total cash requirements	$ 18,500	$ 98,478	$ 116,978	

(a) Includes amounts from ComEd and PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2025. Includes estimated interest payments due to ComEd and PECO financing trusts.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.
(d) These amounts represent Exelon’s expected contributions to its qualified pension plans. Qualified pension contributions for years after 2031 are not included.
(e) Represents the future estimated value at December 31, 2025 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

ComEd

	2026	Beyond 2026	Total	Time Period
Long-term debt[a]	$ 500	$ 12,592	$ 13,092	2026 - 2055
Interest payments on long-term debt[b]	507	9,880	10,387	2026 - 2055
Electric supply procurement	286	273	559	2026 - 2028
Long-term renewable energy and REC commitments	268	7,606	7,874	2026 - 2044
ZEC commitments	156	62	218	2026 - 2027
Other purchase obligations[c]	2,093	1,076	3,169	2026 - 2034
Total cash requirements	$ 3,810	$ 31,489	$ 35,299	

(a) Includes amounts from ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Includes estimated interest payments due to the ComEd financing trust.
(c) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between ComEd and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

PECO

	2026	Beyond 2026	Total	Time Period
Long-term debt[a]	$ —	$ 6,659	$ 6,659	2026 - 2055
Interest payments on long-term debt[b]	266	5,895	6,161	2026 - 2055
Operating leases	1	—	1	2026 - 2035
Fuel purchase agreements[c]	156	578	734	2026 - 2039
Electric supply procurement	767	177	944	2026 - 2027
Other purchase obligations[d]	1,774	632	2,406	2026 - 2035
Total cash requirements	$ 2,964	$ 13,941	$ 16,905	

(a) Includes amounts from PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Includes estimated interest payments due to the PECO financing trusts.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.
(d) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between PECO and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

BGE

	2026	Beyond 2026	Total	Time Period
Long-term debt	$ 350	$ 5,750	$ 6,100	2026 - 2054
Interest payments on long-term debt[(a)]	241	4,749	4,990	2026 - 2054
Operating leases	4	29	33	2026 - 2099
Fuel purchase agreements[(b)]	130	506	636	2026 - 2039
Electric supply procurement	1,396	961	2,357	2026 - 2028
Other purchase obligations[(c)]	2,363	945	3,308	2026 - 2033
Total cash requirements	$ 4,484	$ 12,940	$ 17,424	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.
(c) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between BGE and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

PHI

	2026	Beyond 2026	Total	Time Period
Long-term debt and finance leases	$ 64	$ 9,225	$ 9,289	2026 - 2055
Interest payments on long-term debt[(a)]	389	6,408	6,797	2026 - 2055
Operating leases	13	66	79	2026 - 2032
Fuel purchase agreements[(b)]	35	209	244	2026 - 2031
Electric supply procurement	1,810	1,322	3,132	2026 - 2029
Long-term renewable energy commitments	22	110	132	2026 - 2033
Other purchase obligations[(c)]	1,749	1,534	3,283	2026 - 2033
Total cash requirements	$ 4,082	$ 18,874	$ 22,956	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2025.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.
(c) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between Pepco, DPL, ACE, and PHISCO and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

Pepco

	2026	Beyond 2026	Total	Time Period
Long-term debt and finance leases	$ 6	$ 4,694	$ 4,700	2026 - 2055
Interest payments on long-term debt[(a)]	205	3,553	3,758	2026 - 2055
Operating leases	5	25	30	2026 - 2032
Electric supply procurement	936	711	1,647	2026 - 2029
Other purchase obligations[(b)]	1,032	836	1,868	2026 - 2033
Total cash requirements	$ 2,184	$ 9,819	$ 12,003	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between Pepco and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

DPL

	2026	Beyond 2026	Total	Time Period
Long-term debt and finance leases	$ 53	$ 2,308	$ 2,361	2026 - 2054
Interest payments on long-term debt[(a)]	100	1,695	1,795	2026 - 2054
Operating leases	6	37	43	2025 - 2031
Fuel purchase agreements[(b)]	35	209	244	2026 - 2031
Electric supply procurement	474	307	781	2026 - 2028
Long-term renewable energy commitments	22	110	132	2026 - 2033
Other purchase obligations[(c)]	401	231	632	2026 - 2031
Total cash requirements	$ 1,091	$ 4,897	$ 5,988	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2025.

(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.

(c) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between DPL and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

ACE

	2026	Beyond 2026	Total	Time Period
Long-term debt and finance leases	$ 5	$ 2,038	$ 2,043	2026 - 2055
Interest payments on long-term debt[(a)]	70	1,068	1,138	2026 - 2055
Operating leases	2	5	7	2026 - 2030
Electric supply procurement	400	304	704	2026 - 2028
Other purchase obligations[(b)]	255	428	683	2026 - 2030
Total cash requirements	$ 732	$ 3,843	$ 4,575	

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2025 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.
(b) Represents the future estimated value, as of December 31, 2025, of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between ACE and third-parties for the provision of services and materials, entered into in the normal course of business, and not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

See Note 16 — Commitments and Contingencies and Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' other commitments potentially triggered by future events. Additionally, see below for where to find additional information regarding the financial commitments in the tables above in the Combined Notes to the Consolidated Financial Statements:

Item	Location within Notes to the Consolidated Financial Statements
Long-term debt	Note 14 — Debt and Credit Agreements
Interest payments on long-term debt	Note 14 — Debt and Credit Agreements
Finance leases	Note 9 — Leases
Operating leases	Note 9 — Leases
Long-term renewable energy and REC commitments	Note 2 — Regulatory Matters
ZEC commitments	Note 2 — Regulatory Matters
Pension contributions	Note 12 — Retirement Benefits

Credit Facilities

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' credit facilities and short term borrowing activity.

Capital Structure

As of December 31, 2025, the capital structures of the Registrants consisted of the following:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	62 %	45 %	45 %	48 %	41 %	48 %	48 %	48 %
Long-term debt to affiliates[a]	— %	1 %	1 %	— %	— %	— %	— %	— %
Common equity	37 %	54 %	54 %	52 %	— %	49 %	49 %	48 %
Member’s equity	— %	— %	— %	— %	56 %	— %	— %	— %
Commercial paper and notes payable	1 %	— %	— %	— %	3 %	3 %	3 %	4 %

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(a) Includes approximately $390 million, $206 million, and $184 million owed to unconsolidated affiliates of Exelon, ComEd, and PECO respectively. These special purpose entities were created for the sole purposes of issuing mandatory redeemable trust preferred securities of ComEd and PECO.

Security Ratings

The Registrants’ access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants’ borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant’s securities could increase fees and interest charges under that Registrant’s credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of additional collateral. See Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for ComEd, BGE, PHI, Pepco, DPL, and ACE did not change for the year ended December 31, 2025. On January 17, 2025, Fitch Ratings affirmed and withdrew the long-term and short-term issuer default ratings along with individual securities ratings of the Registrants for commercial reasons. On February 7, 2025, S&P raised its long-term issuer credit rating for Exelon and PECO from 'BBB+' to 'A-', and raised its rating on Exelon’s senior unsecured debt from ‘BBB’ to 'BBB+'. S&P also affirmed its short-term issuer and commercial paper rating for Exelon and PECO of 'A-2'.

Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of December 31, 2025, are presented in the following tables.

	For the Year Ended December 31, 2025		As of December 31, 2025
Exelon Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 578	$ —	$ 250
PECO	336	(253)	—
BSC	—	(413)	(233)
PHI Corporate	—	(85)	(80)
PCI	63	—	63

	For the Year Ended December 31, 2025		As of December 31, 2025
PHI Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Pepco	$ 20	$ (35)	$ —
DPL	48	(1)	—
ACE	—	(46)	—

Shelf Registration Statements

On February 13, 2025, Exelon and ComEd filed a combined shelf registration statement on Form S-3 registering $12.6 billion in aggregate amount of securities, which was declared effective by the SEC on April 8, 2025. The shelf registration statement may be used to issue Exelon debt and equity securities as well as ComEd debt securities through the expiration date of April 8, 2028. On February 21, 2024, PECO and BGE filed with the SEC a standalone automatically effective shelf registration statement, unlimited in amount, which can be used to issue PECO and BGE debt securities through the expiration date of February 20, 2027. The ability of Exelon, ComEd, PECO and BGE to sell securities off their corresponding registration statements will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings, and market conditions.

Pepco, DPL, and ACE periodically issue securities through the private placement markets. Pepco, DPL, and ACE's ability to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, current financial condition, securities ratings, and market conditions.

Regulatory Authorizations

The Utility Registrants are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	At December 31, 2025					
	Short-term Financing Authority			Remaining Long-term Financing Authority		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd[(a)(b)]	FERC	December 31, 2025	$ 2,500	ICC	January 1, 2027, May 1, 2027	$ 1,593
PECO[(a)]	FERC	December 31, 2025	1,500	PAPUC	December 31, 2027	1,850
BGE[(a)]	FERC	December 31, 2025	700	MDPSC	N/A	1,850
Pepco[(a)(c)(d)]	FERC	December 31, 2025	500	MDPSC / DCPSC	December 31, 2025	100
DPL[(a)(c)(e)]	FERC	December 31, 2025	500	MDPSC / DEPSC	December 31, 2025	172
ACE[(f)]	NJBPU	January 1, 2028	350	NJBPU	December 31, 2026	625

(a) On September 8, 2025, ComEd, PECO, BGE, Pepco, and DPL filed applications with the FERC for renewal of their short-term financing authority through December 31, 2027. On November 7, 2025, ComEd, PECO, BGE, Pepco, and DPL received approval for $2.5 billion, $1.5 billion, $900 million, $700 million, and $700 million, respectively, with an effective date of January 1, 2026.
(b) On December 18, 2025, ComEd received approval from the ICC for $2.8 billion in new long-term debt financing authority, with an effective date of January 1, 2026.
(c) The financing authority filed with MDPSC does not have an expiration date, while the financing authority filed with DCPSC and DEPSC have an expiration date of December 31, 2025.
(d) On September 3, 2025 and December 17, 2025, Pepco received approval from the MDPSC and DCPSC, respectively, for $1.1 billion in new long-term financing authority, with an effective date of January 1, 2026.
(e) On September 3, 2025, DPL received approval from the MDSPC and DEPSC, respectively, for $700 million in new long-term financing authority, with an effective date of January 1, 2026.
(f) On November 21, 2025, ACE received approval from the NJBPU to extend their $350 million short-term financing authority through January 1, 2028, with an effective date of November 28, 2025.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants hold commodity and financial instruments that are exposed to the following market risks:

- Commodity price risk, which is discussed further below.
- Counterparty credit risk associated with non-performance by counterparties on executed derivative instruments and participation in all, or some of the established, wholesale spot energy markets that are administered by PJM. The credit policies of PJM may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. See Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of counterparty credit risk related to derivative instruments.
- Equity price and interest rate risk associated with Exelon's pension and OPEB plan trusts. See Note 12 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.
- Interest rate risk associated with changes in interest rates for the Registrants' outstanding long-term debt. This risk is significantly reduced as substantially all of the Registrants' outstanding debt has fixed interest rates. There is inherent interest rate risk related to refinancing maturing debt by issuing new long-term debt. The Registrants use a combination of hybrid, convertible, fixed-rate and variable-rate debt to manage interest rate exposure. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. In addition, Exelon Corporate may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. See Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

The Utility Registrants operate primarily under cost-based rate regulation limiting exposure to the effects of market risk. Hedging programs are utilized to reduce exposure to energy and natural gas price volatility and have no direct earnings impacts as the costs are fully recovered through regulatory-approved recovery mechanisms.

Exelon manages 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. Risk management issues are reported to Exelon's Board of Directors, Exelon's Audit and Risk Committee, and/or the applicable Utility Board Registrant. The Registrants do not execute derivatives for speculative or proprietary trading purposes.

Commodity Price Risk (All Registrants)

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 Exelon purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity and natural gas.

ComEd entered into 20-year floating-to-fixed renewable energy swap contracts beginning in June 2012, which are considered an economic hedge and have changes in fair value recorded to an offsetting regulatory asset or liability. ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. PECO, BGE, Pepco, DPL, and ACE have contracts to procure electric supply that are executed through a competitive procurement process. PECO, BGE, Pepco, DPL, and ACE have certain full requirements contracts, which are considered derivatives and qualify for NPNS, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE, and DPL also have executed derivative natural gas contracts, which qualify for NPNS, to hedge their long-term price risk in the natural gas market.

For additional information on these contracts, see Note 2 — Regulatory Matters and Note 13 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

The following table presents the maturity and source of fair value for Exelon's and ComEd's mark-to-market commodity contract net liabilities. These net liabilities are associated with ComEd's floating-to-fixed energy swap contracts with unaffiliated suppliers. The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of Exelon's and ComEd's total mark-to-market liabilities. Second, the table shows the maturity, by year, of Exelon's and ComEd's commodity contract liabilities giving an indication of when these mark-to-market amounts will settle and require cash. See Note 15 — 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						
Commodity derivative contracts[(a)]:	**2026**	**2027**	**2028**	**2029**	**2030**	**2031 and Beyond**	**Total Fair Value**
Prices based on model or other valuation methods (Level 3)	$ (24)	$ (19)	$ (20)	$ (20)	$ (20)	$ (28)	$ (131)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk (All Registrants)

Credit risk for the Utility Registrants is governed by credit and collection policies, which are aligned with state regulatory requirements. The Utility Registrants are currently obligated to provide service to all electric customers within their franchised territories. The Utility Registrants record an allowance for credit losses, based upon historical experience, current information, and forward-looking risk factors, to provide for the potential loss from nonpayment by these customers. The Utility Registrants will monitor nonpayment from customers and will make any necessary adjustments to the allowance for credit losses. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for credit losses policy. The Utility Registrants did not have any customers representing over 10% of their revenues as of December 31, 2025. See Note 2 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2025, Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2025, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 12, 2026

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd's management concluded that, as of December 31, 2025, ComEd's internal control over financial reporting was effective.

February 12, 2026

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control —Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO's management concluded that, as of December 31, 2025, PECO's internal control over financial reporting was effective.

February 12, 2026

Management’s Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

BGE’s management conducted an assessment of the effectiveness of BGE’s internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE’s management concluded that, as of December 31, 2025, BGE’s internal control over financial reporting was effective.

February 12, 2026

Management's Report on Internal Control Over Financial Reporting

The management of Pepco Holdings LLC (PHI) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

PHI's management conducted an assessment of the effectiveness of PHI's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in *Internal Control —Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PHI's management concluded that, as of December 31, 2025, PHI's internal control over financial reporting was effective.

February 12, 2026

Management’s Report on Internal Control Over Financial Reporting

The management of Potomac Electric Power Company (Pepco) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

Pepco’s management conducted an assessment of the effectiveness of Pepco’s internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Pepco’s management concluded that, as of December 31, 2025, Pepco’s internal control over financial reporting was effective.

February 12, 2026

Management's Report on Internal Control Over Financial Reporting

The management of Delmarva Power & Light Company (DPL) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

DPL's management conducted an assessment of the effectiveness of DPL's internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control —Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, DPL's management concluded that, as of December 31, 2025, DPL's internal control over financial reporting was effective.

February 12, 2026

Management’s Report on Internal Control Over Financial Reporting

The management of Atlantic City Electric Company (ACE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

ACE’s management conducted an assessment of the effectiveness of ACE’s internal control over financial reporting as of December 31, 2025. In making this assessment, management used the criteria in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ACE’s management concluded that, as of December 31, 2025, ACE’s internal control over financial reporting was effective.

February 12, 2026

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1)(i), and the financial statement schedules listed in the index appearing under Item 15(a)(1)(ii), of Exelon Corporation and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management’s Report on Internal Control over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

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

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

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity's cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. As of December 31, 2025, there were $10.57 billion of regulatory assets and $12.14 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 12, 2026

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

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(2)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(2)(ii), of Commonwealth Edison Company and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be

recovered and settled, respectively, in future rates. As of December 31, 2025, there were $3.28 billion of regulatory assets and $10.01 billion of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 12, 2026

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

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(3)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(3)(ii), of PECO Energy Company and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be

recovered and settled, respectively, in future rates. As of December 31, 2025, there were $1.35 billion of regulatory assets and $589 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 12, 2026

We have served as the Company's auditor since 1932.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Baltimore Gas and Electric Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(4)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(4)(ii), of Baltimore Gas and Electric Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled,

respectively, in future rates. As of December 31, 2025, there were $979 million of regulatory assets and $626 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Baltimore, Maryland
February 12, 2026

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(5)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(5)(ii), of Pepco Holdings LLC and its subsidiaries (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be

recovered and settled, respectively, in future rates. As of December 31, 2025, there were $1.91 billion of regulatory assets and $825 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 12, 2026

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

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(6)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(6)(ii), of Potomac Electric Power Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled,

respectively, in future rates. As of December 31, 2025, there were $587 million of regulatory assets and $281 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 12, 2026

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(7)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(7)(ii), of Delmarva Power & Light Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled,

respectively, in future rates. As of December 31, 2025, there were $286 million of regulatory assets and $358 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 12, 2026

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(8)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(8)(ii), of Atlantic City Electric Company and its subsidiary (the "Company") (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments.

The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 2 to the consolidated financial statements, the Company applies the authoritative guidance for accounting for certain types of regulation, which requires management to record in the consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria, (i) rates are established or approved by a third-party regulator; (ii) rates are designed to recover the entity’s cost of providing services or products; and (iii) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Company accounts for its regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction under state public utility laws and the FERC under various Federal laws. Upon updates in material regulatory and legislative proceedings, where applicable, management will record new regulatory assets or liabilities and will assess whether it is probable that its currently recorded regulatory assets and liabilities will be

recovered and settled, respectively, in future rates. As of December 31, 2025, there were $652 million of regulatory assets and $185 million of regulatory liabilities.

The principal considerations for our determination that performing procedures relating to the Company's accounting for the effects of rate regulation is a critical audit matter are the high degree of audit effort to assess the impact of regulation on accounting for regulatory assets and liabilities and to evaluate the complex audit evidence related to whether the regulatory assets and liabilities will be recovered and settled.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to accounting for regulatory matters and evaluation of new and existing regulatory assets and liabilities. These procedures also included, among others, obtaining the Company's correspondence with regulators, evaluating the reasonableness of management's interpretation of regulatory guidance and proceedings and the related accounting implications, and recalculating regulatory assets and liabilities based on provisions outlined in rate orders and other correspondence with regulators.

/s/ PricewaterhouseCoopers LLP
Philadelphia, Pennsylvania
February 12, 2026

We have served as the Company's auditor since 1998.

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2025	2024	2023
Operating revenues			
Electric operating revenues	$ 22,655	$ 21,338	$ 19,267
Natural gas operating revenues	2,349	1,782	1,764
Revenues from alternative revenue programs	(746)	(92)	696
Total operating revenues	24,258	23,028	21,727
Operating expenses			
Purchased power	7,944	8,214	7,648
Purchased fuel	723	469	593
Operating and maintenance	5,177	4,940	4,559
Depreciation and amortization	3,640	3,594	3,506
Taxes other than income taxes	1,629	1,504	1,408
Total operating expenses	19,113	18,721	17,714
Gain on sale of assets	3	12	10
Operating income	5,148	4,319	4,023
Other income and (deductions)			
Interest expense, net	(2,102)	(1,889)	(1,704)
Interest expense to affiliates	(25)	(25)	(25)
Other, net	270	262	408
Total other income and (deductions)	(1,857)	(1,652)	(1,321)
Income before income taxes	3,291	2,667	2,702
Income taxes	523	207	374
Net income attributable to common shareholders	$ 2,768	$ 2,460	$ 2,328
Comprehensive income, net of income taxes			
Net income	$ 2,768	$ 2,460	$ 2,328
Other comprehensive (loss) income, net of income taxes			
Pension and non-pension postretirement benefit plans:			
Actuarial losses reclassified to periodic benefit cost	22	28	26
Pension and non-pension postretirement benefit plans valuation adjustments	(52)	(70)	(109)
Unrealized (loss) gain on cash flow hedges	(12)	48	(5)
Other comprehensive (loss) income	(42)	6	(88)
Comprehensive income attributable to common shareholders	$ 2,726	$ 2,466	$ 2,240
Average shares of common stock outstanding:			
Basic	1,011	1,003	996
Assumed exercise and/or distributions of stock-based awards[a]	1	—	1
Diluted	1,012	1,003	997
Earnings per average common share			
Basic	$ 2.74	$ 2.45	$ 2.34
Diluted	$ 2.73	$ 2.45	$ 2.34

(a) The dilutive effects of stock-based compensation awards are calculated using the treasury stock method for all periods presented.

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 2,768	$ 2,460	$ 2,328
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion	3,643	3,596	3,506
Gain on sales of assets	(3)	(12)	(10)
Deferred income taxes and amortization of investment tax credits	391	128	319
Net fair value changes related to derivatives	—	—	22
Other non-cash operating activities	1,331	592	(335)
Changes in assets and liabilities:			
Accounts receivable	(1,691)	(644)	(37)
Inventories	(22)	(56)	(45)
Accounts payable and accrued expenses	260	(37)	(191)
Collateral (paid) received, net	(10)	33	(146)
Income taxes	121	(4)	48
Regulatory assets and liabilities, net	156	(50)	(439)
Pension and non-pension postretirement benefit contributions	(342)	(180)	(129)
Other assets and liabilities	(348)	(257)	(188)
Net cash flows provided by operating activities	6,254	5,569	4,703
Cash flows from investing activities			
Capital expenditures	(8,529)	(7,097)	(7,408)
Proceeds from sales of assets	4	38	25
Other investing activities	—	17	8
Net cash flows used in investing activities	(8,525)	(7,042)	(7,375)
Cash flows from financing activities			
Changes in short-term borrowings	(747)	(265)	(313)
Proceeds from short-term borrowings with maturities greater than 90 days	—	150	400
Repayments on short-term borrowings with maturities greater than 90 days	(500)	(549)	(150)
Issuance of long-term debt	6,075	4,974	5,825
Retirement of long-term debt	(1,311)	(1,557)	(1,713)
Issuance of common stock	691	148	140
Dividends paid on common stock	(1,617)	(1,524)	(1,433)
Proceeds from employee stock plans	36	43	41
Other financing activities	(94)	(109)	(114)
Net cash flows provided by financing activities	2,533	1,311	2,683
Increase (decrease) in cash, restricted cash, and cash equivalents	262	(162)	11
Cash, restricted cash, and cash equivalents at beginning of period	939	1,101	1,090
Cash, restricted cash, and cash equivalents at end of period	$ 1,201	$ 939	$ 1,101
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 553	$ 301	$ (215)
Increase (decrease) in PP&E related to ARO update	13	16	(13)

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	626	$	357
Restricted cash and cash equivalents		525		541
Accounts receivable				
Customer accounts receivable	3,732		3,144	
Customer allowance for credit losses	(435)		(406)	
Customer accounts receivable, net		3,297		2,738
Other accounts receivable	1,879		1,123	
Other allowance for credit losses	(94)		(107)	
Other accounts receivable, net		1,785		1,016
Inventories, net				
Fossil fuel		88		72
Materials and supplies		780		781
Regulatory assets		1,359		1,940
Prepaid renewable energy credits		563		494
Other		523		445
Total current assets		9,546		8,384
Property, plant, and equipment (net of accumulated depreciation and amortization of $20,080 and $18,445 as of December 31, 2025 and 2024, respectively)		84,318		78,182
Deferred debits and other assets				
Regulatory assets		9,214		8,710
Goodwill		6,630		6,630
Receivable related to Regulatory Agreement Units		4,755		4,026
Investments		312		290
Other		1,795		1,562
Total deferred debits and other assets		22,706		21,218
Total assets	$	116,570	$	107,784

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 612	$ 1,859
Long-term debt due within one year	1,665	1,453
Accounts payable	3,721	2,994
Accrued expenses	1,582	1,468
Payables to affiliates	5	5
Customer deposits	533	446
Regulatory liabilities	1,128	411
Mark-to-market derivative liabilities	30	29
Unamortized energy contract liabilities	5	5
Renewable energy credit obligations	473	429
Other	577	512
Total current liabilities	10,331	9,611
Long-term debt	47,413	42,947
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,715	12,793
Regulatory liabilities	11,016	10,198
Pension obligations	1,749	1,745
Non-pension postretirement benefit obligations	546	472
Asset retirement obligations	321	301
Mark-to-market derivative liabilities	106	103
Unamortized energy contract liabilities	16	21
Other	2,169	2,282
Total deferred credits and other liabilities	29,638	27,915
Total liabilities	87,772	80,863
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 1,023 shares and 1,005 shares outstanding as of December 31, 2025 and 2024, respectively)	22,106	21,338
Treasury stock, at cost (2 shares as of December 31, 2025 and 2024)	(123)	(123)
Retained earnings	7,577	6,426
Accumulated other comprehensive loss, net	(762)	(720)
Total shareholders' equity	28,798	26,921
Total liabilities and shareholders' equity	$ 116,570	$ 107,784

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Equity
Balance at December 31, 2022	995,830	$ 20,908	$ (123)	$ 4,597	$ (638)	$ 24,744
Net income	—	—	—	2,328	—	2,328
Long-term incentive plan activity	659	19	—	—	—	19
Employee stock purchase plan activity	1,173	47	—	—	—	47
Issuance of common stock	3,587	140	—	—	—	140
Common stock dividends ($1.44/common share)	—	—	—	(1,435)	—	(1,435)
Other comprehensive loss, net of income taxes	—	—	—	—	(88)	(88)
Balance at December 31, 2023	1,001,249	$ 21,114	$ (123)	$ 5,490	$ (726)	$ 25,755
Net income	—	—	—	2,460	—	2,460
Long-term incentive plan activity	464	26	—	—	—	26
Employee stock purchase plan activity	1,344	50	—	—	—	50
Issuance of common stock	3,989	148	—	—	—	148
Common stock dividends ($1.52/common share)	—	—	—	(1,524)	—	(1,524)
Other comprehensive income, net of income taxes	—	—	—	—	6	6
Balance at December 31, 2024	1,007,046	$ 21,338	$ (123)	$ 6,426	$ (720)	$ 26,921
Net income	—	—	—	2,768	—	2,768
Long-term incentive plan activity	323	34	—	—	—	34
Employee stock purchase plan activity	931	43	—	—	—	43
Issuance of common stock	16,101	691	—	—	—	691
Common stock dividends ($1.60/common share)	—	—	—	(1,617)	—	(1,617)
Other comprehensive loss, net of income taxes	—	—	—	—	(42)	(42)
Balance at December 31, 2025	1,024,401	$ 22,106	$ (123)	$ 7,577	$ (762)	$ 28,798

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Operating revenues			
Electric operating revenues	$ 7,842	$ 8,362	$ 7,272
Revenues from alternative revenue programs	(596)	(151)	556
Operating revenues from affiliates	21	8	16
Total operating revenues	7,267	8,219	7,844
Operating expenses			
Purchased power	1,782	3,042	2,816
Operating and maintenance	1,306	1,284	1,096
Operating and maintenance from affiliates	404	419	354
Depreciation and amortization	1,560	1,514	1,403
Taxes other than income taxes	409	376	369
Total operating expenses	5,461	6,635	6,038
Gain on sale of assets	—	5	—
Operating income	1,806	1,589	1,806
Other income and (deductions)			
Interest expense, net	(517)	(487)	(464)
Interest expense to affiliates, net	(13)	(14)	(13)
Other, net	132	94	75
Total other income and (deductions)	(398)	(407)	(402)
Income before income taxes	1,408	1,182	1,404
Income taxes	261	116	314
Net income	$ 1,147	$ 1,066	$ 1,090
Comprehensive income	$ 1,147	$ 1,066	$ 1,090

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 1,147	$ 1,066	$ 1,090
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	1,560	1,514	1,403
Gain on sales of assets	—	(5)	—
Deferred income taxes and amortization of investment tax credits	39	(19)	196
Other non-cash operating activities	740	232	(536)
Changes in assets and liabilities:			
Accounts receivable	(1,026)	(185)	(138)
Receivables from and payables to affiliates, net	3	4	(2)
Inventories	17	(15)	(82)
Accounts payable and accrued expenses	77	(115)	(87)
Collateral (paid) received, net	(36)	30	69
Income taxes	(1)	(114)	106
Regulatory assets and liabilities, net	506	246	(60)
Pension and non-pension postretirement benefit contributions	(209)	(25)	(41)
Other assets and liabilities	(152)	99	(70)
Net cash flows provided by operating activities	2,665	2,713	1,848
Cash flows from investing activities			
Capital expenditures	(2,899)	(2,195)	(2,576)
Other investing activities	6	7	8
Net cash flows used in investing activities	(2,893)	(2,188)	(2,568)
Cash flows from financing activities			
Changes in short-term borrowings	(36)	(166)	(225)
Proceeds from short-term borrowings with maturities greater than 90 days	—	—	400
Repayments on short-term borrowings with maturities greater than 90 days	—	(400)	(150)
Issuance of long-term debt	725	800	975
Retirement of long-term debt	—	(250)	—
Dividends paid on common stock	(813)	(776)	(746)
Contributions from parent	391	227	655
Other financing activities	(8)	(14)	(14)
Net cash flows provided by (used in) financing activities	259	(579)	895
Increase (decrease) in cash, restricted cash, and cash equivalents	31	(54)	175
Cash, restricted cash, and cash equivalents at beginning of period	632	686	511
Cash, restricted cash, and cash equivalents at end of period	$ 663	$ 632	$ 686
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 233	$ (17)	$ (10)

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	159	$	105
Restricted cash and cash equivalents		454		486
Accounts receivable				
Customer accounts receivable	1,058		994	
Customer allowance for credit losses	(115)		(109)	
Customer accounts receivable, net		943		885
Other accounts receivable	1,155		290	
Other allowance for credit losses	(23)		(34)	
Other accounts receivable, net		1,132		256
Receivables from affiliates		5		4
Inventories, net		268		292
Regulatory assets		595		1,159
Other		217		141
Total current assets		3,773		3,328
Property, plant, and equipment (net of accumulated depreciation and amortization of $8,291 and $7,619 as of December 31, 2025 and 2024, respectively)		32,255		30,211
Deferred debits and other assets				
Regulatory assets		2,687		2,562
Goodwill		2,625		2,625
Receivable related to Regulatory Agreement Units		4,313		3,780
Investments		6		6
Prepaid pension asset		1,284		1,165
Other		1,342		1,073
Total deferred debits and other assets		12,257		11,211
Total assets	$	48,285	$	44,750

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 36
Long-term debt due within one year	500	—
Accounts payable	1,033	748
Accrued expenses	474	463
Payables to affiliates	81	77
Customer deposits	192	134
Regulatory liabilities	846	197
Mark-to-market derivative liabilities	25	29
Other	288	270
Total current liabilities	3,439	1,954
Long-term debt	12,253	12,030
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,828	5,601
Regulatory liabilities	9,163	8,421
Asset retirement obligations	193	167
Non-pension postretirement benefit obligations	151	156
Mark-to-market derivative liabilities	106	103
Other	1,341	1,232
Total deferred credits and other liabilities	16,782	15,680
Total liabilities	32,680	29,870
Commitments and contingencies		
Shareholders' equity		
Common stock ($12.50 par value, 250 shares authorized, 127 shares outstanding as of December 31, 2025 and 2024)	1,588	1,588
Other paid-in capital	11,019	10,628
Retained earnings	2,998	2,664
Total shareholders' equity	15,605	14,880
Total liabilities and shareholders' equity	$ 48,285	$ 44,750

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Earnings	Total Shareholders' Equity
Balance at December 31, 2022	$ 1,588	$ 9,746	$ 2,030	$ 13,364
Net income	—	—	1,090	1,090
Common stock dividends	—	—	(746)	(746)
Contributions from parent	—	655	—	655
Balance at December 31, 2023	$ 1,588	$ 10,401	$ 2,374	$ 14,363
Net income	—	—	1,066	1,066
Common stock dividends	—	—	(776)	(776)
Contributions from parent	—	227	—	227
Balance at December 31, 2024	$ 1,588	$ 10,628	$ 2,664	$ 14,880
Net income	—	—	1,147	1,147
Common stock dividends	—	—	(813)	(813)
Contributions from parent	—	391	—	391
Balance at December 31, 2025	$ 1,588	$ 11,019	$ 2,998	$ 15,605

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2025	2024	2023
Operating revenues			
Electric operating revenues	$ 3,818	$ 3,312	$ 3,202
Natural gas operating revenues	854	645	690
Revenues from alternative revenue programs	—	6	(7)
Operating revenues from affiliates	12	10	9
Total operating revenues	4,684	3,973	3,894
Operating expenses			
Purchased power	1,436	1,265	1,270
Purchased fuel	297	212	274
Operating and maintenance	946	875	786
Operating and maintenance from affiliates	249	245	217
Depreciation and amortization	454	428	397
Taxes other than income taxes	240	218	202
Total operating expenses	3,622	3,243	3,146
Gain on sale of assets	—	4	—
Operating income	1,062	734	748
Other income and (deductions)			
Interest expense, net	(249)	(221)	(192)
Interest expense to affiliates, net	(11)	(11)	(9)
Other, net	41	37	36
Total other income and (deductions)	(219)	(195)	(165)
Income before income taxes	843	539	583
Income taxes	29	(12)	20
Net income	$ 814	$ 551	$ 563
Comprehensive income	$ 814	$ 551	$ 563

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 814	$ 551	$ 563
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	454	428	397
Gain on sales of assets	—	(4)	—
Deferred income taxes and amortization of investment tax credits	(69)	(63)	(43)
Other non-cash operating activities	78	59	13
Changes in assets and liabilities:			
Accounts receivable	(238)	(210)	67
Receivables from and payables to affiliates, net	(6)	4	(1)
Inventories	(12)	1	34
Accounts payable and accrued expenses	118	23	(78)
Collateral received, net	6	—	—
Income taxes	283	(76)	86
Regulatory assets and liabilities, net	(33)	27	(31)
Pension and non-pension postretirement benefit contributions	(13)	(4)	(1)
Other assets and liabilities	21	18	13
Net cash flows provided by operating activities	1,403	754	1,019
Cash flows from investing activities			
Capital expenditures	(1,867)	(1,553)	(1,426)
Other investing activities	3	6	2
Net cash flows used in investing activities	(1,864)	(1,547)	(1,424)
Cash flows from financing activities			
Change in short-term borrowings	(192)	27	(74)
Issuance of long-term debt	1,050	575	575
Retirement of long-term debt	(350)	—	(50)
Dividends paid on common stock	(546)	(400)	(405)
Contributions from parent	577	595	348
Other financing activities	(10)	(7)	(6)
Net cash flows provided by financing activities	529	790	388
Increase (decrease) in cash, restricted cash, and cash equivalents	68	(3)	(17)
Cash, restricted cash, and cash equivalents at beginning of period	48	51	68
Cash, restricted cash, and cash equivalents at end of period	$ 116	$ 48	$ 51
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 94	$ 103	$ (56)

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	116	$	48
Accounts receivable				
Customer accounts receivable	811		670	
Customer allowance for credit losses	(137)		(133)	
Customer accounts receivable, net		674		537
Other accounts receivable	144		145	
Other allowance for credit losses	(18)		(18)	
Other accounts receivable, net		126		127
Inventories, net				
Fossil fuel		43		37
Materials and supplies		83		79
Prepaid renewable energy credits		55		51
Regulatory assets		72		65
Other		34		29
Total current assets		1,203		973
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,131 and $4,042 as of December 31, 2025 and 2024, respectively)		15,922		14,392
Deferred debits and other assets				
Regulatory assets		1,275		1,003
Receivable related to Regulatory Agreement Units		442		247
Investments		45		41
Prepaid pension asset		441		435
Other		34		32
Total deferred debits and other assets		2,237		1,758
Total assets	$	19,362	$	17,123

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025	2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 192
Long-term debt due within one year	—	350
Accounts payable	811	639
Accrued expenses	483	166
Payables to affiliates	35	41
Customer deposits	93	80
Renewable energy credit obligations	56	52
Regulatory liabilities	140	122
Other	40	28
Total current liabilities	1,658	1,670
Long-term debt	6,396	5,354
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,594	2,433
Regulatory liabilities	449	253
Asset retirement obligations	26	27
Non-pension postretirement benefit obligations	286	287
Other	109	100
Total deferred credits and other liabilities	3,464	3,100
Total liabilities	11,702	10,308
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 500 shares authorized, 170 shares outstanding as of December 31, 2025 and 2024)	5,222	4,645
Retained earnings	2,438	2,170
Total shareholder's equity	7,660	6,815
Total liabilities and shareholder's equity	$ 19,362	$ 17,123

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2022	$ 3,702	$ 1,861	$ 5,563
Net income	—	563	563
Common stock dividends	—	(405)	(405)
Contributions from parent	348	—	348
Balance at December 31, 2023	$ 4,050	$ 2,019	$ 6,069
Net income	—	551	551
Common stock dividends	—	(400)	(400)
Contributions from parent	595	—	595
Balance at December 31, 2024	$ 4,645	$ 2,170	$ 6,815
Net income	—	814	814
Common stock dividends	—	(546)	(546)
Contributions from parent	577	—	577
Balance at December 31, 2025	$ 5,222	$ 2,438	$ 7,660

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2025	2024	2023
Operating revenues			
Electric operating revenues	$ 4,037	$ 3,407	$ 3,065
Natural gas operating revenues	1,264	957	869
Revenues from alternative revenue programs	(87)	52	84
Operating revenues from affiliates	8	10	9
Total operating revenues	5,222	4,426	4,027
Operating expenses			
Purchased power	1,890	1,460	1,311
Purchased fuel	331	191	220
Operating and maintenance	815	790	520
Operating and maintenance from affiliates	251	246	221
Depreciation and amortization	632	638	654
Taxes other than income taxes	370	345	319
Total operating expenses	4,289	3,670	3,245
Operating income	933	756	782
Other income and (deductions)			
Interest expense, net	(247)	(216)	(182)
Other, net	51	36	18
Total other income and (deductions)	(196)	(180)	(164)
Income before income taxes	737	576	618
Income taxes	159	49	133
Net income	$ 578	$ 527	$ 485
Comprehensive income	$ 578	$ 527	$ 485

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 578	$ 527	$ 485
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	632	638	654
Deferred income taxes and amortization of investment tax credits	86	5	66
Other non-cash operating activities	170	38	(1)
Changes in assets and liabilities:			
Accounts receivable	(244)	(142)	89
Receivables from and payables to affiliates, net	(9)	14	(5)
Inventories	3	(5)	47
Accounts payable and accrued expenses	(18)	35	(75)
Collateral received (paid), net	4	(1)	(22)
Income taxes	169	(54)	37
Regulatory assets and liabilities, net	(97)	(84)	(292)
Pension and non-pension postretirement benefit contributions	(44)	(37)	(19)
Other assets and liabilities	(1)	(39)	(13)
Net cash flows provided by operating activities	1,229	895	951
Cash flows from investing activities			
Capital expenditures	(1,657)	(1,420)	(1,367)
Other investing activities	9	12	7
Net cash flows used in investing activities	(1,648)	(1,408)	(1,360)
Cash flows from financing activities			
Changes in short-term borrowings	(175)	(161)	(72)
Issuance of long-term debt	650	800	700
Retirement of long-term debt	—	—	(300)
Dividends paid on common stock	(393)	(368)	(316)
Contributions from parent	531	237	385
Other financing activities	(8)	(9)	(7)
Net cash flows provided by financing activities	605	499	390
Increase (decrease) in cash, restricted cash, and cash equivalents	186	(14)	(19)
Cash, restricted cash, and cash equivalents at beginning of period	34	48	67
Cash, restricted cash, and cash equivalents at end of period	$ 220	$ 34	$ 48
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 153	$ 156	$ (44)

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents		$ 217		$ 33
Restricted cash and cash equivalents		3		1
Accounts receivable				
Customer accounts receivable	887		654	
Customer allowance for credit losses	(68)		(56)	
Customer accounts receivable, net		819		598
Other accounts receivable	100		113	
Other allowance for credit losses	(4)		(6)	
Other accounts receivable, net		96		107
Receivables from affiliates		1		—
Inventories, net				
Fossil fuel		36		29
Materials and supplies		74		84
Prepaid utility taxes		126		115
Regulatory assets		175		207
Prepaid renewable energy credits		189		157
Other		14		17
Total current assets		1,750		1,348
Property, plant, and equipment (net of accumulated depreciation and amortization of $5,234 and $5,005 as of December 31, 2025 and 2024, respectively)		14,385		13,134
Deferred debits and other assets				
Regulatory assets		804		788
Investments		10		10
Prepaid pension asset		194		218
Other		41		44
Total deferred debits and other assets		1,049		1,060
Total assets		$ 17,184		$ 15,542

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 175
Long-term debt due within one year	350	—
Accounts payable	640	515
Accrued expenses	352	176
Payables to affiliates	39	48
Customer deposits	125	118
Regulatory liabilities	31	12
Renewable energy credit obligations	194	160
Other	39	39
Total current liabilities	1,770	1,243
Long-term debt	5,691	5,395
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,242	2,099
Regulatory liabilities	595	636
Asset retirement obligations	36	36
Non-pension postretirement benefit obligations	144	150
Other	104	97
Total deferred credits and other liabilities	3,121	3,018
Total liabilities	10,582	9,656
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 0 shares[(a)] authorized, 0 shares[(a)] outstanding as of December 31, 2025 and 2024)	4,014	3,483
Retained earnings	2,588	2,403
Total shareholder's equity	6,602	5,886
Total liabilities and shareholder's equity	$ 17,184	$ 15,542

(a) In millions, shares round to zero. Number of shares is 1,500 authorized and 1,000 outstanding as of December 31, 2025 and 2024.

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2022	$ 2,861	$ 2,075	$ 4,936
Net income	—	485	485
Common stock dividends	—	(316)	(316)
Contributions from parent	385	—	385
Balance at December 31, 2023	$ 3,246	$ 2,244	$ 5,490
Net income	—	527	527
Common stock dividends	—	(368)	(368)
Contributions from parent	237	—	237
Balance at December 31, 2024	$ 3,483	$ 2,403	$ 5,886
Net income	—	578	578
Common stock dividends	—	(393)	(393)
Contributions from parent	531	—	531
Balance at December 31, 2025	$ 4,014	$ 2,588	$ 6,602

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Operating revenues			
Electric operating revenues	$ 6,957	$ 6,257	$ 5,748
Natural gas operating revenues	231	180	205
Revenues from alternative revenue programs	(63)	1	64
Operating revenues from affiliates	10	10	9
Total operating revenues	7,135	6,448	6,026
Operating expenses			
Purchased power	2,836	2,447	2,250
Purchased fuel	95	66	98
Operating and maintenance	1,123	1,046	1,110
Operating and maintenance from affiliates	204	204	179
Depreciation and amortization	935	947	990
Taxes other than income taxes	568	528	487
Total operating expenses	5,761	5,238	5,114
Gain (loss) on sales of assets	3	(1)	9
Operating income	1,377	1,209	921
Other income and (deductions)			
Interest expense, net	(408)	(373)	(323)
Interest expense to affiliates, net	(3)	(3)	—
Other, net	72	97	108
Total other income and (deductions)	(339)	(279)	(215)
Income before income taxes	1,038	930	706
Income taxes	239	189	116
Net income	$ 799	$ 741	$ 590
Comprehensive income	$ 799	$ 741	$ 590

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 799	$ 741	$ 590
Adjustments to reconcile net income to net cash flows used in operating activities:			
Depreciation, amortization, and accretion	937	947	990
(Gain) loss on sales of assets	(3)	1	(9)
Deferred income taxes and amortization of investment tax credits	132	73	29
Other non-cash operating activities	241	188	110
Changes in assets and liabilities:			
Accounts receivable	(204)	(110)	(79)
Receivables from and payables to affiliates, net	(1)	2	(8)
Inventories	(32)	(37)	(42)
Accounts payable and accrued expenses	8	66	40
Collateral received (paid), net	17	—	(196)
Income taxes	(7)	(33)	65
Regulatory assets and liabilities, net	(192)	(223)	(61)
Pension and non-pension postretirement benefit contributions	(50)	(86)	(24)
Other assets and liabilities	(47)	(119)	(101)
Net cash flows provided by operating activities	1,598	1,410	1,304
Cash flows from investing activities			
Capital expenditures	(2,056)	(1,863)	(1,988)
Proceeds from sales of long-lived assets	4	—	10
Other investing activities	—	—	8
Net cash flows used in investing activities	(2,052)	(1,863)	(1,970)
Cash flows from financing activities			
Changes in short-term borrowings	82	136	(20)
Issuance of long-term debt	650	1,100	1,075
Retirement of long-term debt	(150)	(583)	(500)
Change in Exelon intercompany money pool	17	(2)	21
Distributions to member	(710)	(706)	(513)
Contributions from member	568	505	475
Other financing activities	(25)	(38)	(41)
Net cash flows provided by financing activities	432	412	497
Decrease in cash, restricted cash, and cash equivalents	(22)	(41)	(169)
Cash, restricted cash, and cash equivalents at beginning of period	163	204	373
Cash, restricted cash, and cash equivalents at end of period	$ 141	$ 163	$ 204
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 79	$ 76	$ (109)

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)		December 31, 2025		December 31, 2024
ASSETS				
Current assets				
Cash and cash equivalents		$ 103		$ 139
Restricted cash and cash equivalents		38		24
Accounts receivable				
Customer accounts receivable	975		827	
Customer allowance for credit losses	(115)		(108)	
Customer accounts receivable, net		860		719
Other accounts receivable	292		284	
Other allowance for credit losses	(49)		(49)	
Other accounts receivable, net		243		235
Receivable from affiliates		14		8
Inventories, net				
Fossil fuel		9		7
Materials and supplies		357		325
Prepaid utility taxes		77		70
Regulatory assets		352		323
Prepaid renewable energy credits		201		194
Other		34		36
Total current assets		2,288		2,080
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,350 and $3,728 as of December 31, 2025 and 2024, respectively)		21,377		20,053
Deferred debits and other assets				
Regulatory assets		1,556		1,570
Goodwill		4,005		4,005
Investments		158		152
Prepaid pension asset		199		252
Other		132		185
Total deferred debits and other assets		6,050		6,164
Total assets		$ 29,715		$ 28,297

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 612	$ 530
Long-term debt due within one year	64	290
Accounts payable	816	721
Accrued expenses	359	367
Payables to affiliates	71	66
Borrowings from Exelon intercompany money pool	80	63
Customer deposits	123	113
Regulatory liabilities	103	69
Unamortized energy contract liabilities	5	5
Renewable energy credit obligations	223	217
Other	121	124
Total current liabilities	2,577	2,565
Long-term debt	9,526	8,834
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,391	3,190
Regulatory liabilities	722	794
Asset retirement obligations	62	67
Non-pension postretirement benefit obligations	24	31
Unamortized energy contract liabilities	16	21
Other	418	473
Total deferred credits and other liabilities	4,633	4,576
Total liabilities	16,736	15,975
Commitments and contingencies		
Member's equity		
Membership interest	13,130	12,562
Undistributed losses	(151)	(240)
Total member's equity	12,979	12,322
Total liabilities and member's equity	$ 29,715	$ 28,297

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Changes in Member's Equity

(In millions)	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance at December 31, 2022	$ 11,582	$ (352)	$ 11,230
Net income	—	590	590
Distribution to member	—	(513)	(513)
Contributions from member	475	—	475
Balance at December 31, 2023	$ 12,057	$ (275)	$ 11,782
Net income	—	741	741
Distribution to member	—	(706)	(706)
Contributions from member	505	—	505
Balance at December 31, 2024	$ 12,562	$ (240)	$ 12,322
Net income	—	799	799
Distribution to member	—	(710)	(710)
Contributions from member	568	—	568
Balance at December 31, 2025	$ 13,130	$ (151)	$ 12,979

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Operating revenues			
Electric operating revenues	$ 3,497	$ 3,017	$ 2,793
Revenues from alternative revenue programs	(49)	15	22
Operating revenues from affiliates	6	7	9
Total operating revenues	3,454	3,039	2,824
Operating expenses			
Purchased power	1,262	1,055	974
Operating and maintenance	379	283	336
Operating and maintenance from affiliates	246	251	236
Depreciation and amortization	433	407	441
Taxes other than income taxes	455	424	390
Total operating expenses	2,775	2,420	2,377
Gain (loss) on sales of assets	1	(1)	9
Operating income	680	618	456
Other income and (deductions)			
Interest expense, net	(214)	(195)	(165)
Interest income from affiliates, net	—	3	—
Other, net	41	54	66
Total other income and (deductions)	(173)	(138)	(99)
Income before income taxes	507	480	357
Income taxes	106	90	51
Net income	$ 401	$ 390	$ 306
Comprehensive income	$ 401	$ 390	$ 306

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 401	$ 390	$ 306
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion	435	407	441
(Gain) loss on sales of assets	(1)	1	(9)
Deferred income taxes and amortization of investment tax credits	51	24	(15)
Other non-cash operating activities	111	33	53
Changes in assets and liabilities:			
Accounts receivable	(121)	(26)	(29)
Receivables from and payables to affiliates, net	4	6	(3)
Inventories	(4)	(10)	(24)
Accounts payable and accrued expenses	1	67	6
Collateral received (paid), net	12	—	(25)
Income taxes	(33)	(30)	60
Regulatory assets and liabilities, net	(93)	(85)	(45)
Pension and non-pension postretirement benefit contributions	(9)	(9)	(12)
Other assets and liabilities	(29)	(84)	(5)
Net cash flows provided by operating activities	725	684	699
Cash flows from investing activities			
Capital expenditures	(957)	(929)	(957)
Proceeds from sale of long-lived assets	2	—	10
Other investing activities	—	—	8
Net cash flows used in investing activities	(955)	(929)	(939)
Cash flows from financing activities			
Changes in short-term borrowings	103	68	(167)
Issuance of long-term debt	275	675	350
Retirement of long-term debt	—	(400)	—
Dividends paid on common stock	(327)	(359)	(252)
Contributions from parent	193	260	308
Other financing activities	(10)	(20)	(26)
Net cash flows provided by financing activities	234	224	213
Increase (decrease) in cash, restricted cash, and cash equivalents	4	(21)	(27)
Cash, restricted cash, and cash equivalents at beginning of period	51	72	99
Cash, restricted cash, and cash equivalents at end of period	$ 55	$ 51	$ 72
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 56	$ 30	$ (55)

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

	December 31,			
(In millions)	2025		2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	22	$	30
Restricted cash and cash equivalents		33		21
Accounts receivable				
Customer accounts receivable	484		395	
Customer allowance for credit losses	(69)		(59)	
Customer accounts receivable, net		415		336
Other accounts receivable	154		142	
Other allowance for credit losses	(26)		(27)	
Other accounts receivable, net		128		115
Receivables from affiliates		—		1
Inventories, net		174		169
Regulatory assets		182		157
Prepaid renewable energy credits		171		165
Other		59		55
Total current assets		1,184		1,049
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,784 and $4,522 as of December 31, 2025 and 2024, respectively)		10,747		10,097
Deferred debits and other assets				
Regulatory assets		405		446
Investments		141		135
Prepaid pension asset		194		222
Other		57		51
Total deferred debits and other assets		797		854
Total assets	$	12,728	$	12,000

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 303	$ 200
Long-term debt due within one year	6	6
Accounts payable	418	360
Accrued expenses	173	201
Payables to affiliates	37	37
Customer deposits	61	55
Regulatory liabilities	13	17
Merger related obligation	20	22
Renewable energy credit obligations	174	169
Other	64	51
Total current liabilities	1,269	1,118
Long-term debt	4,626	4,356
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,604	1,509
Regulatory liabilities	268	310
Asset retirement obligations	45	49
Other	214	223
Total deferred credits and other liabilities	2,131	2,091
Total liabilities	8,026	7,565
Commitments and contingencies		
Shareholder's equity		
Common stock ($0.01 par value, 200 shares authorized, 0 shares[(a)] outstanding as of December 31, 2025 and 2024)	3,528	3,335
Retained earnings	1,174	1,100
Total shareholder's equity	4,702	4,435
Total liabilities and shareholder's equity	$ 12,728	$ 12,000

(a) In millions, shares round to zero. Number of shares is 100 outstanding as of December 31, 2025 and 2024.

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2022	$ 2,767	$ 1,015	$ 3,782
Net income	—	306	306
Common stock dividends	—	(252)	(252)
Contributions from parent	308	—	308
Balance at December 31, 2023	$ 3,075	$ 1,069	$ 4,144
Net income	—	390	390
Common stock dividends	—	(359)	(359)
Contributions from parent	260	—	260
Balance at December 31, 2024	$ 3,335	$ 1,100	$ 4,435
Net income	—	401	401
Common stock dividends	—	(327)	(327)
Contributions from parent	193	—	193
Balance at December 31, 2025	$ 3,528	$ 1,174	$ 4,702

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2025	2024	2023
Operating revenues			
Electric operating revenues	$ 1,747	$ 1,602	$ 1,460
Natural gas operating revenues	231	180	205
Revenues from alternative revenue programs	(16)	(2)	15
Operating revenues from affiliates	9	7	8
Total operating revenues	1,971	1,787	1,688
Operating expenses			
Purchased power	766	694	639
Purchased fuel	95	66	98
Operating and maintenance	213	196	193
Operating and maintenance from affiliates	178	181	171
Depreciation and amortization	252	245	244
Taxes other than income taxes	88	79	75
Total operating expenses	1,592	1,461	1,420
Operating income	379	326	268
Other income and (deductions)			
Interest expense, net	(102)	(94)	(74)
Interest income from affiliates, net	—	1	—
Other, net	16	25	18
Total other income and (deductions)	(86)	(68)	(56)
Income before income taxes	293	258	212
Income taxes	69	49	35
Net income	$ 224	$ 209	$ 177
Comprehensive income	$ 224	$ 209	$ 177

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2025	2024	2023
Cash flows from operating activities			
Net income	$ 224	$ 209	$ 177
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	252	245	244
Deferred income taxes and amortization of investment tax credits	32	16	4
Other non-cash operating activities	57	40	13
Changes in assets and liabilities:			
Accounts receivable	(70)	(46)	6
Receivables from and payables to affiliates, net	(3)	2	2
Inventories	(14)	(20)	(5)
Accounts payable and accrued expenses	20	22	(7)
Collateral received (paid), net	2	2	(121)
Income taxes	16	(24)	26
Regulatory assets and liabilities, net	(35)	(51)	25
Pension and non-pension postretirement benefit contributions	(1)	(3)	(4)
Other assets and liabilities	6	16	13
Net cash flows provided by operating activities	486	408	373
Cash flows from investing activities			
Capital expenditures	(534)	(556)	(562)
Net cash flows used in investing activities	(534)	(556)	(562)
Cash flows from financing activities			
Changes in short-term borrowings	17	81	(52)
Issuance of long-term debt	125	175	650
Retirement of long-term debt	—	(33)	(500)
Dividends paid on common stock	(202)	(220)	(133)
Contributions from parent	107	160	99
Other financing activities	(10)	(8)	(11)
Net cash flows provided by financing activities	37	155	53
(Decrease) increase in cash, restricted cash, and cash equivalents	(11)	7	(136)
Cash, restricted cash, and cash equivalents at beginning of period	23	16	152
Cash, restricted cash, and cash equivalents at end of period	$ 12	$ 23	$ 16
Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 13	$ 41	$ (6)

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents	$	9	$	21
Restricted cash and cash equivalents		3		2
Accounts receivable				
Customer accounts receivable	253		210	
Customer allowance for credit losses	(19)		(17)	
Customer accounts receivable, net		234		193
Other accounts receivable	75		63	
Other allowance for credit losses	(10)		(9)	
Other accounts receivable, net		65		54
Receivables from affiliates		2		—
Inventories, net				
Fossil fuel		9		6
Materials and supplies		107		95
Prepaid utility taxes		29		26
Regulatory assets		72		60
Prepaid renewable energy credits		30		29
Other		13		16
Total current assets		573		502
Property, plant, and equipment, (net of accumulated depreciation and amortization of $2,241 and $2,075 as of December 31, 2025 and 2024, respectively)		5,855		5,540
Deferred debits and other assets				
Regulatory assets		214		215
Other		147		164
Total deferred debits and other assets		361		379
Total assets	$	6,789	$	6,421

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 161	$ 144
Long-term debt due within one year	53	130
Accounts payable	218	187
Accrued expenses	70	55
Payables to affiliates	25	26
Customer deposits	36	34
Regulatory liabilities	42	42
Renewable energy credit obligations	49	48
Other	22	22
Total current liabilities	676	688
Long-term debt	2,291	2,090
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	996	946
Regulatory liabilities	316	325
Asset retirement obligations	12	13
Other	127	117
Total deferred credits and other liabilities	1,451	1,401
Total liabilities	4,418	4,179
Commitments and contingencies		
Shareholder's equity		
Common stock ($2.25 par value, 0 shares[(a)] authorized, 0 shares[(a)] outstanding as of December 31, 2025 and 2024, respectively)	1,722	1,615
Retained earnings	649	627
Total shareholder's equity	2,371	2,242
Total liabilities and shareholder's equity	$ 6,789	$ 6,421

(a) In millions, shares round to zero. Number of shares is 1,000 authorized and outstanding as of December 31, 2025 and 2024.

Delmarva Power & Light Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance at December 31, 2022	$ 1,356	$ 594	$ 1,950
Net income	—	177	177
Common stock dividends	—	(133)	(133)
Contributions from parent	99	—	99
Balance at December 31, 2023	$ 1,455	$ 638	$ 2,093
Net income	—	209	209
Common stock dividends	—	(220)	(220)
Contributions from parent	160	—	160
Balance at December 31, 2024	$ 1,615	$ 627	$ 2,242
Net income	—	224	224
Common stock dividends	—	(202)	(202)
Contributions from parent	107	—	107
Balance at December 31, 2025	$ 1,722	$ 649	$ 2,371

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2025	2024	2023
Operating revenues			
Electric operating revenues	$ 1,712	$ 1,638	$ 1,493
Revenues from alternative revenue programs	2	(12)	27
Operating revenues from affiliates	4	2	2
Total operating revenues	1,718	1,628	1,522
Operating expenses			
Purchased power	808	698	637
Operating and maintenance	173	206	233
Operating and maintenance from affiliates	155	162	153
Depreciation and amortization	248	278	283
Taxes other than income taxes	9	9	8
Total operating expenses	1,393	1,353	1,314
Gain on sale of assets	2	—	—
Operating income	327	275	208
Other income and (deductions)			
Interest expense, net	(82)	(74)	(72)
Interest expense to affiliates, net	—	(5)	—
Other, net	10	14	20
Total other income and (deductions)	(72)	(65)	(52)
Income before income taxes	255	210	156
Income taxes	67	55	36
Net income	$ 188	$ 155	$ 120
Comprehensive income	$ 188	$ 155	$ 120

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Cash flows from operating activities			
Net income	$ 188	$ 155	$ 120
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	248	278	283
Gain on sales of assets	(2)	—	—
Deferred income taxes and amortization of investment tax credits	47	39	27
Other non-cash operating activities	38	70	—
Changes in assets and liabilities:			
Accounts receivable	(14)	(35)	(57)
Receivables from and payables to affiliates, net	(3)	(8)	(4)
Inventories	(13)	(8)	(12)
Accounts payable and accrued expenses	(8)	(18)	27
Collateral received (paid), net	5	—	(50)
Income taxes	9	(5)	—
Regulatory assets and liabilities, net	(62)	(88)	(47)
Pension and non-pension postretirement benefit contributions	(4)	(9)	(3)
Other assets and liabilities	(1)	(44)	(83)
Net cash flows provided by operating activities	428	327	201
Cash flows from investing activities			
Capital expenditures	(390)	(373)	(460)
Proceeds from sale of long-lived assets	2	—	—
Net cash flows used in investing activities	(388)	(373)	(460)
Cash flows from financing activities			
Changes in short-term borrowings	(38)	(13)	199
Issuance of long-term debt	250	250	75
Retirement of long-term debt	(150)	(150)	—
Dividends paid on common stock	(183)	(127)	(126)
Contributions from parent	98	85	65
Other financing activities	(7)	(6)	(5)
Net cash flows (used in) provided by financing activities	(30)	39	208
Increase (decrease) in cash, restricted cash, and cash equivalents	10	(7)	(51)
Cash, restricted cash, and cash equivalents at beginning of period	14	21	72
Cash, restricted cash, and cash equivalents at end of period	$ 24	$ 14	$ 21

Supplemental cash flow information			
Increase (decrease) in capital expenditures not paid	$ 11	$ 4	$ (47)

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2025		December 31, 2024	
ASSETS				
Current assets				
Cash and cash equivalents		$ 22		$ 14
Restricted cash and cash equivalents		2		—
Accounts receivable				
Customer accounts receivable	239		223	
Customer allowance for credit losses	(27)		(32)	
Customer accounts receivable, net		212		191
Other accounts receivable	64		79	
Other allowance for credit losses	(13)		(13)	
Other accounts receivable, net		51		66
Receivables from affiliates		12		7
Inventories, net		76		62
Regulatory assets		93		101
Other		8		6
Total current assets		476		447
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,956 and $1,798 as of December 31, 2025 and 2024, respectively)		4,556		4,366
Deferred debits and other assets				
Regulatory assets		559		502
Other		41		34
Total deferred debits and other assets		600		536
Total assets		$ 5,632		$ 5,349

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2025	December 31, 2024
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 148	$ 186
Long-term debt due within one year	5	154
Accounts payable	168	163
Accrued expenses	64	52
Payables to affiliates	24	22
Customer deposits	26	24
Regulatory liabilities	48	10
Other	13	10
Total current liabilities	496	621
Long-term debt	2,028	1,779
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	869	816
Regulatory liabilities	137	146
Other	74	62
Total deferred credits and other liabilities	1,080	1,024
Total liabilities	3,604	3,424
Commitments and contingencies		
Shareholder's equity		
Common stock ($3.00 par value, 25 shares authorized, 9 shares outstanding as of December 31, 2025 and 2024)	2,013	1,915
Retained earnings	15	10
Total shareholder's equity	2,028	1,925
Total liabilities and shareholder's equity	$ 5,632	$ 5,349

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings (Deficit)	Total Shareholder's Equity
Balance at December 31, 2022	$ 1,765	$ (12)	$ 1,753
Net income	—	120	120
Common stock dividends	—	(126)	(126)
Contributions from parent	65	—	65
Balance at December 31, 2023	$ 1,830	$ (18)	$ 1,812
Net income	—	155	155
Common stock dividends	—	(127)	(127)
Contributions from parent	85	—	85
Balance at December 31, 2024	$ 1,915	$ 10	$ 1,925
Net income	—	188	188
Common stock dividends	—	(183)	(183)
Contributions from parent	98	—	98
Balance at December 31, 2025	$ 2,013	$ 15	$ 2,028

See the Combined Notes to Consolidated Financial Statements

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged in the energy transmission and distribution businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE.

Name of Registrant	Business	Service Territories
Commonwealth Edison Company	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL, and ACE	Service Territories of Pepco, DPL, and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland.
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey
	Transmission and distribution of electricity to retail customers	

Basis of Presentation (All Registrants)

This is a combined annual report of all Registrants. The Notes to the Consolidated Financial Statements apply to the Registrants as indicated parenthetically next to each corresponding disclosure. When appropriate, the Registrants are named specifically for their related activities and disclosures. Each of the Registrants' Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, finance, engineering, customer operations, transmission and distribution planning, asset management, system operations, and power procurement, to PHI operating Registrants. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

As of December 31, 2025, 2024, and 2023, Exelon owned 100% of PECO, BGE, and PHI and more than 99% of ComEd. PHI owns 100% of Pepco, DPL, and ACE.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (All Registrants)

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

Regulatory Accounting (All Registrants)

For their regulated electric and gas operations, the Registrants reflect the effects of cost-based rate regulation in their financial statements, which is required for entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates designed to recover costs can be charged to and collected from customers. The Registrants account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, PAPUC, MDPSC, DCPSC, DEPSC, and NJBPU, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. The Registrants' regulatory assets and liabilities as of the balance sheet date are probable of being recovered or settled in future rates. If a separable portion of the Registrants' business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their financial statements. See Note 2 — Regulatory Matters for additional information.

With the exception of income tax-related regulatory assets and liabilities, the Registrants classify regulatory assets and liabilities with a recovery or settlement period greater than one year as both current and noncurrent in their Consolidated Balance Sheets, with the current portion representing the amount expected to be recovered from or refunded to customers over the next twelve-month period as of the balance sheet date. Income tax-related regulatory assets and liabilities are classified entirely as noncurrent in the Registrants' Consolidated Balance Sheets to align with the classification of the related deferred income tax balances.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (All Registrants)

Operating Revenues. The Registrants' operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of power and natural gas and utility revenues from ARPs. The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that the entities expect to be entitled to in exchange for those goods or services. The primary sources of revenue include regulated electric and natural gas tariff sales, distribution, and transmission services. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, distributed generation rebates, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its distribution multi-year rate plan, distribution revenue decoupling mechanisms, and formula rate mechanisms. BGE, Pepco, DPL, and ACE record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC, DCPSC, and/or NJBPU in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL, and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. The Registrants recognize all ARP revenues that will be collected within 24 months of the end of the annual period in which they are recorded. See Note 2 — Regulatory Matters for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges, and fees, that are levied by state or local governments on the sale or distribution of electricity and gas. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 20 — Supplemental Financial Information for taxes that are presented on a gross basis.

Leases (All Registrants)

The Registrants recognize a ROU asset and lease liability for operating and finance leases when the term is greater than one year. Operating lease ROU assets are included in Other deferred debits and other assets and operating lease liabilities are included in Other current liabilities and Other deferred credits and other liabilities on the Consolidated Balance Sheets. Finance lease ROU assets are included in Property, plant, and equipment, net and finance lease liabilities are included in Long-term debt due within one year and Long-term debt on the Consolidated Balance Sheets. The ROU asset is measured as the sum of (1) the present value of all remaining fixed and in-substance fixed payments using the rate implicit in the lease whenever that is readily determinable or each Registrant’s incremental borrowing rate, (2) any lease payments made at or before the commencement date (less any lease incentives received), and (3) any initial direct costs incurred. The lease liability is measured the same as the ROU asset, but excludes any payments made before the commencement date and initial direct costs incurred. Lease terms include options to extend or terminate the lease if it is reasonably certain they will be exercised. The Registrants include non-lease components, which are service-related costs that are not integral to the use of the asset, in the measurement of the ROU asset and lease liability.

Expense for operating leases and leases with a term of one year or less is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the derivation of benefit from use of the leased property. Variable lease payments are recognized in the period in which the related obligation is incurred. Operating lease expense, finance lease expense, and variable lease payments are primarily recorded to Operating and maintenance expense on the Registrants’ Statements of Operations and Comprehensive Income.

Income from operating leases, including subleases, is recognized on a straight-line basis over the term of the lease, unless another systematic and rational basis is more representative of the pattern in which income is earned over the term of the lease. Variable lease income is recognized in the period in which the related obligation is performed. Operating lease income and variable lease income are recorded to Operating revenues on the Registrants’ Statements of Operations and Comprehensive Income.

The Registrants’ operating and finance leases consist primarily of real estate, including office buildings, and vehicles and equipment. The Registrants account for land right arrangements that provide for exclusive use as leases while shared use land arrangements are generally not leases. The Registrants do not account for secondary use pole attachments as leases. See Note 9 — Leases for additional information.

Income Taxes (All Registrants)

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

Cash and Cash Equivalents (All Registrants)

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

Restricted Cash and Cash Equivalents (All Registrants)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2025 and 2024, the Registrants' restricted cash and cash equivalents primarily represented the following items:

Registrant	Description
Exelon	Payment of medical, dental, vision, and long-term disability benefits, in addition to the items listed below for the Utility Registrants.
ComEd	Collateral held from suppliers associated with energy and REC procurement contracts, any over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA.
PECO	Proceeds from the sales of assets that were subject to PECO’s mortgage indenture.
BGE	Collateral held from energy suppliers.
PHI	Payment of merger commitments, collateral held from energy suppliers associated with procurement contracts, and payments of REC procurement costs to NJBPU program participants through an administrator.
Pepco	Payment of merger commitments and collateral held from energy suppliers.
DPL	Collateral held from energy suppliers.
ACE	Payment of REC procurement costs to NJBPU program participants through an administrator.

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Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2025 and 2024, the Registrants' noncurrent restricted cash and cash equivalents primarily represented ComEd’s alternative compliance payments received from RES pursuant to FEJA and are included in other deferred debits and other assets.

See Note 14 — Debt and Credit Agreements and Note 20 — Supplemental Financial Information for additional information.

Allowance for Credit Losses on Customer Receivables (All Registrants)

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

The allowance for credit losses is estimated based on historical experience, current conditions, and forward-looking risk factors. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. Adjustments to the allowance for credit losses are primarily recorded to Operating and maintenance expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income or Regulatory assets and liabilities on the Registrants' Consolidated Balance Sheets. See Note 2 — Regulatory Matters for additional information regarding the regulatory recovery of credit losses on customer accounts receivable.

The Registrants have certain non-customer receivables in Other deferred debits and other assets which primarily are with governmental agencies and other high-quality counterparties with no history of default. As such, the allowance for credit losses related to these receivables is not material. The Registrants monitor these balances and will record an allowance if there are indicators of a decline in credit quality. See Note 5 — Accounts Receivable for additional information.

Inventories (All Registrants)

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory. Fossil fuel and Materials and supplies are generally included in inventory when purchased. Fossil fuel is expensed to Purchased power and fuel expense when used or sold. Materials and supplies generally includes transmission and distribution materials and are expensed to Operating and maintenance or capitalized to Property, plant, and equipment, as appropriate, when installed or used.

Property, Plant, and Equipment (All Registrants)

Property, plant, and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs and indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes AFUDC for regulated property at the Utility Registrants. The cost of repairs and maintenance and minor replacements of property is charged to Operating and maintenance expense as incurred.

Third parties reimburse the Utility Registrants for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant, and equipment, net.

Upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation consistent with the composite and group methods of depreciation. Depreciation expense at ComEd, BGE, Pepco, DPL, and ACE includes the estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs. PECO’s removal costs are capitalized to accumulated depreciation when incurred and recorded to depreciation expense over the life of the new asset constructed consistent with PECO’s regulatory recovery method.

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

AFUDC. AFUDC is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to an allowance that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

See Note 6 — Property, Plant, and Equipment, Note 7 — Jointly Owned Electric Utility Plant and Note 20 — Supplemental Financial Information for additional information.

Depreciation and Amortization (All Registrants)

Depreciation is generally recorded over the estimated service lives of property, plant, and equipment on a straight-line basis using the group or composite methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. ComEd, BGE, Pepco, DPL, and ACE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. PECO's removal costs are capitalized to accumulated depreciation when incurred and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method. The estimated service lives for the Registrants are based on a combination of depreciation studies and historical retirements. See Note 6 — Property, Plant, and Equipment for additional information regarding depreciation.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants’ Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd’s electric distribution rate reconciliations and energy efficiency formula rate regulatory assets and the Utility Registrants' transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities is generally recorded to Income tax expense. Except for the regulatory assets and liabilities discussed above, amortization is generally recorded to Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income when the recovery period is more than one year.

See Note 2 — Regulatory Matters and Note 20 — Supplemental Financial Information for additional information regarding the amortization of the Registrants' regulatory assets.

Asset Retirement Obligations (All Registrants)

The Registrants estimate and recognize a liability for their legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. The Registrants update their AROs either annually or on a rotational basis at least once every three years, based on a risk profile, unless circumstances warrant more frequent updates. The updates factor in new cost estimates, credit-adjusted, risk-free rates (CARFR) and escalation rates, and the timing of cash flows. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through an increase to Regulatory assets. See Note 8 — Asset Retirement Obligations for additional information.

Guarantees (All Registrants)

If necessary, the Registrants recognize a liability at the time of issuance of a guarantee for the fair value of the obligations they have undertaken. The liability is reduced or eliminated as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 16 — Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets (All Registrants). The Registrants evaluate the carrying value of long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying value of those assets may not be recoverable. Indicators of impairment may include specific regulatory disallowance, abandonment, or plans to dispose of a long-lived asset significantly before the end of its useful life. When the estimated undiscounted future cash flows attributable to the long-lived asset may not be recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset over its fair value.

Goodwill (Exelon, ComEd, and PHI). Goodwill represents the excess of the purchase price paid over the estimated fair value of the net assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized but is assessed for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 10 — Intangible Assets for additional information.

Derivative Financial Instruments (All Registrants)

Derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including NPNS. For derivatives that qualify and are designated as cash flow hedges, changes in fair value each period are initially recorded in AOCI and recognized in earnings when the underlying hedged transaction affects earnings. Amounts recognized in earnings are recorded in Interest expense, net on the Consolidated Statement of Operations and Comprehensive Income based on the activity the transaction is economically hedging. Cash inflows and outflows related to derivative instruments designated as cash flow hedges are included as a component of operating, investing, or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For derivatives intended to serve as economic hedges, which are not designated for hedge accounting, changes in fair value each period are recognized in earnings or as a regulatory asset or liability. Amounts recognized in earnings are recorded in Electric operating revenues, Purchased power and fuel, or Interest expense in the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. Changes in fair value are also recorded as a regulatory asset or liability when there is an ability to recover or return the associated costs or benefits in accordance with regulatory requirements. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing, or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of the hedged item. See Note 2 — Regulatory Matters and Note 13 — Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and OPEB plans.

The plan obligations and costs of providing benefits under these plans are measured as of December 31. The measurement involves various factors, assumptions, and accounting elections. The impact of assumption changes or experiences different from those assumed on pension and OPEB obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 12 — Retirement Benefits for additional information.

New Accounting Standards (All Registrants)

New Accounting Standards Adopted in 2025: In 2025, the Registrants adopted the following new FASB authoritative accounting guidance.

Improvements to Income Tax Disclosures (Issued December 2023). Provides additional disclosure requirements related to the effective tax rate reconciliation and income taxes paid. Under the revised guidance for the effective tax reconciliations, entities would be required to disclose: (1) eight specific categories in the effective tax rate reconciliation in both percentages and reporting currency amount, (2) additional information for reconciling items over a certain threshold, (3) explanation of individual reconciling items disclosed, and (4) provide a qualitative description of the state and local jurisdictions that contribute to the majority of the state income tax expense. For each annual period presented, the new standard requires disclosure of the year-to-date amount of income taxes paid (net of refunds received) disaggregated by federal, state, and foreign. It also requires additional disaggregated information on income taxes paid (net of refunds received) to an individual jurisdiction equal to or greater than 5% of total income taxes paid (net of refunds received). The standard is effective for annual periods beginning January 1, 2025. The Registrants' adoption of this guidance in the fourth quarter of 2025 resulted in an expanded effective tax rate reconciliation. The standard has been applied retrospectively. See Note 11 — Income Taxes for additional information.

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2025: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements as of December 31, 2025. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) in their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact the Registrants' financial reporting.

Disaggregation of Income Statement Expenses (Issued November 2024). Provides additional disclosure requirements related to relevant expense captions of income statement expense line items. The revised guidance requires a new tabular disclosure of disaggregated income statement expenses including a break out of (1) purchases of inventory, (2) employee compensation, (3) depreciation, (4) intangible asset amortization, (5) depreciation, depletion, and amortization recognized as part of oil and gas producing activities included in each relevant expense line item on the income statement. The tabular disaggregation should include certain amounts already required to be disclosed under GAAP elsewhere. Any remaining amounts not separately disaggregated quantitatively should include a qualitative description. Additionally, on an annual basis, the standard requires disclosure of management’s definition of selling expenses and the amount of expense. The standard is effective January 1, 2027, with early adoption permitted.

Targeted Improvements to the Accounting for Internal Use Software (Issued September 2025). Modernizes the accounting for costs related to internal use software to align with the agile basis utilized to develop software. The revised guidance removes references to project stages, clarifies the capitalization threshold for software costs, and expands disclosure requirements for capitalized software. Cost capitalization will begin with (1) management authorized and committed project funding and (2) it is 'probable' to complete the project and the software will be used in its intended function. The standard is effective for annual and interim periods beginning January 1, 2028. The standard can be implemented using a prospective, retrospective, or modified retrospective transition approach with early adoption permitted.

Accounting for Government Grants (Issued December 2025). Establishes accounting guidance for government grants received by defining (1) a grant related to an asset and (2) a grant related to income. Updates provide that a grant should not be recognized until it is probable the entity will comply with grant conditions and the grant will be received. A grant related to an asset is required to be recognized on the balance sheet either as (1) deferred income (deferred income approach) or (2) an adjustment to carrying value (cost accumulation approach). Grants related to income and grants related to assets for which the deferred income approach is elected should be recognized in earnings on a systematic basis over the periods in which an entity recognizes expenses for the costs the grant was intended to compensate. The standard is effective for annual and interim periods beginning January 1, 2029, with early adoption permitted.

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

2. Regulatory Matters (All Registrants)

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

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2025.

Completed Distribution Base Rate Case Proceedings

Registrant/ Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	January 17, 2023	Electric	$ 1,487	$ 1,045	8.905%	December 19, 2024	January 1, 2024
	April 26, 2024 (amended on September 11, 2024)	Electric	$ 624	$ 623	9.89%	October 31, 2024	January 1, 2025
PECO - Pennsylvania	March 28, 2024	Electric	$464	$ 354	N/A	December 12, 2024	January 1, 2025
		Natural Gas	$111	$ 78			
BGE - Maryland	February 17, 2023	Electric	$ 313	$ 179	9.50%	December 14, 2023	January 1, 2024
		Natural Gas	$ 289	$ 229	9.45%		
Pepco - District of Columbia	April 13, 2023 (amended February 27, 2024)	Electric	$ 186	$ 123	9.50%	November 26, 2024	January 1, 2025
Pepco - Maryland	May 16, 2023 (amended February 23, 2024)	Electric	$ 111	$ 45	9.50%	June 10, 2024	April 1, 2024
DPL - Maryland	May 19, 2022	Electric	$ 38	$ 29	9.60%	December 14, 2022	January 1, 2023
DPL - Delaware	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	$ 28	9.60%	April 18, 2024	July 15, 2023
	September 20, 2024 (amended September 5, 2025)	Natural Gas	$ 37	$ 22	9.60%	December 17, 2025	January 1, 2026
ACE - New Jersey	February 15, 2023 (amended August 21, 2023)	Electric	$ 92	$ 45	9.60%	November 17, 2023	December 1, 2023
	November 21, 2024	Electric	$ 109	$ 54	9.60%	November 21, 2025	December 1, 2025

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

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Pepco - Maryland	October 14, 2025	Electric	$ 133	10.50%	Third quarter of 2026
DPL - Delaware[(a)]	December 9, 2025	Electric	$ 45	10.50%	Third quarter of 2027

(a) DPL can implement interim rates on July 9, 2026, subject to refund.

ComEd Distribution Base Rate Case Proceedings

The ICC approved ComEd's four-year MRP for the period January 1, 2024 through December 31, 2027. The MRP was originally approved by the ICC on December 14, 2023 and was subsequently amended on January 10, 2024, April 18, 2024 and December 19, 2024. The December 19, 2024 order provided a total revenue requirement increase of $1.045 billion inclusive of rate increases of approximately $752 million in 2024, $80 million in 2025, $102 million in 2026, and $111 million in 2027.

On March 20, 2025, ComEd filed its annual revenue balancing reconciliation for 2024. This reconciliation, which is a component of revenue decoupling, reflected a revenue reduction of $55 million, effective January 1, 2026.

On December 18, 2025, the ICC approved ComEd's 2024 MRP Reconciliation reflecting a revenue increase of $243 million, including the tax benefit of NOLCs. While NOLCs are included in the MRP Reconciliation per the final order, the impacts of the NOLCs will not be reflected in the financial statements until the PLR is received from the IRS. See Note 11 — Income Taxes for additional information on NOLCs. On January 20, 2026, the Illinois Attorney General filed an Application for Rehearing of the December 18 order, which focuses solely on NOLCs. On February 5, 2026, the ICC denied the Illinois Attorney General's Application for Rehearing.

On October 31, 2024, the Delivery Reconciliation Amount for 2023 defined in Rider Delivery Service Pricing Reconciliation (Rider DSPR) was approved. Rider DSPR allows for the reconciliation of the revenue requirement in effect in the final years in which formula rates were determined and until such time as new rates were established under ComEd's approved MRP. The 2024 order reconciled the delivery service rates in effect in 2023 with the actual delivery service costs incurred in 2023. The reconciliation revenue requirement provides for a weighted average debt and equity return on distribution rate base of 7.02%, inclusive of an allowed ROE of 9.89%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points.

PECO Distribution Base Rate Case Proceedings

On December 12, 2024, the PAPUC issued their Opinions and Orders which approved the non-unanimous partial settlements with limited modifications for both the electric and natural gas base rate cases, and denied the Weather Normalization Adjustment requested in the natural gas base rate case.

PECO’s approved annual electric revenue requirement increase of $354 million is partially offset by a one-time credit of $64 million in 2025. In addition, the PAPUC approved the recovery of storm damage costs incurred by PECO in January 2024, up to $23 million, subject to review for reasonableness and prudency in PECO’s next distribution rate case.

BGE Distribution Base Rate Case Proceedings

In February 2023, BGE filed its three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026 to the MDPSC, which was approved in December 2023 and went into effect on January 1, 2024. The MDSPC awarded BGE electric revenue requirement increases of $41 million, $113 million, and $25 million with an approved ROE of 9.50% in 2024, 2025, and 2026, respectively, and natural gas revenue requirement increases of $126 million, $62 million, and $41 million with an approved ROE of 9.45% in 2024, 2025, and 2026, respectively. The requested revenue requirement increases will be used to recover capital investments designed to increase the resilience of the electric and gas distribution systems and support Maryland's climate and regulatory initiatives.

The MDPSC also approved a portion of the requested 2021 and 2022 reconciliation amounts, which were recovered through separate electric and gas riders between March 2024 and February 2025. As such, the reconciliation amounts are not included in the approved revenue increases. The 2021 reconciliation amounts are $13 million and $7 million for electric and gas, respectively, and the 2022 reconciliation amounts are $39 million and $15 million for electric and gas, respectively. In April 2024, BGE filed with the MDPSC its request for recovery of the 2023 reconciliation amounts of $79 million and $73 million for electric and gas, respectively, with supporting testimony and schedules. In December 2025, the MDPSC authorized BGE to recover $31 million and $46 million for electric and gas, respectively, beginning in February 2026 and extending through December 2027, in the reconciliation rider. In addition to the amounts approved in the reconciliation rider, the MDPSC provided for additional regulatory assets related to minor storms of $24 million (to be recovered over 5 years) and the Baltimore City conduit of $4 million (to be reviewed along with a cost-benefit analysis in BGE's next rate case).

Pepco District of Columbia Distribution Base Rate Case Proceedings

On April 13, 2023, Pepco filed an electric base rate case with the DCPSC (amended February 27, 2024) requesting a total revenue requirement increase of $186 million and an ROE of 10.50%. The DCPSC issued an order approving the two-year cumulative multi-year plan on November 26, 2024, which included a total revenue requirement increase of $123 million with an ROE of 9.50% effective January 1, 2025 through December 31, 2026. The DCPSC awarded Pepco electric incremental revenue requirement increases of $99 million and $24 million for 2025 and 2026, respectively.

Pepco Maryland Distribution Base Rate Case Proceedings

On May 16, 2023, Pepco filed an electric base rate case with the MDPSC (amended February 23, 2024) requesting a total revenue requirement increase of $111 million (before offsets) and an ROE of 10.50%. The MDPSC issued an order on June 10, 2024 awarding Pepco a one-year multi-year plan for April 1, 2024 through March 31, 2025 which included an incremental revenue requirement increase of $45 million and an ROE of 9.50%. The MDPSC did not adopt the requested revenue requirement increases of $80 million (before offsets), $51 million, and $14 million as filed for 2025, 2026, and the 2027 nine-month extension period, respectively. The MDPSC also approved the requested reconciliation amounts for the 12-month periods ending March 31, 2022, and March 31, 2023, which will be recovered through a rider between August 2024 through March 2026. As such, the reconciliation amounts are not included in the approved revenue requirement increases. The reconciliation amounts are $1 million and $7 million, for the 12-month periods ending March 31, 2022, and March 31, 2023, respectively. In July 2024, Pepco filed its request with the MDPSC, for which it is awaiting approval, for recovery of the reconciliation amounts of $31 million for the 12-month period ended March 31, 2024, with supporting testimony and schedules.

DPL Maryland Distribution Base Rate Case Proceedings

On May 19, 2022, DPL filed an electric base rate case with the MDPSC requesting a total revenue requirement increase of $38 million based on an ROE of 10.25%. On December 14, 2022, the MDPSC issued an order awarding DPL a total revenue requirement increase of $29 million with an ROE of 9.60%. The order reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025, with rates remaining in effect subsequent to the multi-year plan period. The MDPSC awarded DPL electric incremental revenue requirement increases of $17 million, $6 million, and $6 million for 2023, 2024, and 2025, respectively.

DPL Delaware Distribution Base Rate Case Proceedings

On December 15, 2022, DPL filed an electric base rate case with the DEPSC (amended September 29, 2023) requesting a total revenue requirement increase of $39 million and an ROE of 10.50%. On April 18, 2024, the DEPSC issued an order awarding DPL a total revenue requirement increase of $28 million with an ROE of 9.60%, effective July 15, 2023. As part of the approved order, the DEPSC approved the Significant Storm Expense Rate Rider (Rider SSER) which will allow DPL to recover expenses associated with qualified storms. A qualified storm will be an individual storm for which DPL incurs expenses between $5 million and $15 million. The Rider SSER allows DPL to recover significant storm damage expenses for the previous 12-month period over a future 24-month period. For individual storm events for which DPL incurs expenses of more than $15 million, the future recovery period will be evaluated on a case-by-case basis and the unamortized balance will earn a return at DPL's authorized long-term cost of debt. The Rider SSER will have an annual true-up filing, subject to DEPSC review and approval.

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

ACE New Jersey Distribution Base Rate Case Proceedings

On February 15, 2023, ACE filed an electric base rate case with the NJBPU (amended August 21, 2023) requesting a total revenue requirement increase of $92 million, before NJ sales and use tax, and an ROE of 10.50%. On November 17, 2023, the NJBPU issued an order awarding ACE electric revenue requirement increases, before NJ sales and use tax, of $36 million and $9 million effective December 1, 2023 and February 1, 2024, respectively, with an ROE of 9.60%.

On November 21, 2024, ACE filed an electric base rate case with the NJBPU requesting a total revenue requirement increase of $109 million, before NJ sales and use tax, and an ROE of 10.70%. On November 21, 2025, the NJBPU issued an order awarding ACE an electric revenue requirement increase, before NJ sales and use tax, of $54 million effective December 1, 2025, with an ROE of 9.60%. In addition, the NJBPU approved the recovery through a regulatory asset of work stoppage costs that were incurred by ACE in 2023 of $38 million.

Transmission Formula Rates

The Utility Registrants' transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, and PECO is required to file on or before May 31, with the resulting rates effective on June 1 of the same year. The annual update for ComEd is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The update for ComEd also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year (annual reconciliation). The annual update for PECO is based on prior year actual costs and current year projected capital additions, accumulated depreciation, and accumulated deferred income taxes. The annual update for BGE, Pepco, DPL, and ACE is based on prior year actual costs and current year projected capital additions, accumulated depreciation, depreciation and amortization expense, and accumulated deferred income taxes. The update for PECO, BGE, Pepco, DPL, and ACE also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2025, the following increases/(decreases) were included in the Utility Registrants' electric transmission formula rate updates:

Registrant[(a)]	Initial Revenue Requirement Increase (Decrease)	Annual Reconciliation Increase (Decrease)	Total Revenue Requirement Increase (Decrease)[(b)]	Allowed Return on Rate Base[(c)]	Allowed ROE[(d)]
ComEd	$ 78	$ 49	$ 127	8.13 %	11.50 %
PECO	$ 9	$ 13	$ 22	7.54 %	10.35 %
BGE	$ 21	$ 21	$ 35 [(e)]	7.53 %	10.50 %
Pepco	$ 35	$ 16	$ 51	7.71 %	10.50 %
DPL	$ 32	$ (9)	$ 23	7.48 %	10.50 %
ACE	$ (11)	$ (46)	$ (57)	7.16 %	10.50 %

(a) All rates are effective June 1, 2025 - May 31, 2026, subject to review by interested parties pursuant to review protocols of each Utility Registrants' tariffs.
(b) For the Utility Registrants, except for PECO, while the transmission filings reflect the tax benefit of NOLCs, the impacts of the NOLCs will not be reflected in the financial statements until the PLR is received from the IRS. See Note 11 — Income Taxes for additional information on NOLCs.
(c) Represents the weighted average debt and equity return on transmission rate base.
(d) The rate of return on common equity for each Utility Registrant includes a 50-basis-point incentive adder for being a member of an RTO.
(e) The increase in BGE's transmission revenue requirement includes a $7 million reduction related to a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.

Other State Regulatory Matters

Illinois Regulatory Matters

CEJA (Exelon and ComEd). On September 15, 2021, the Governor of Illinois signed into law CEJA. CEJA includes, among other features, (1) procurement of CMCs from qualifying nuclear-powered generating facilities,

(2) a requirement to file a general rate case or a new four-year MRP no later than January 20, 2023 to establish rates effective after ComEd’s existing performance-based distribution formula rate sunsets, (3) requirements that ComEd and the ICC initiate and conduct various regulatory proceedings on subjects including ethics, spending, grid investments, and performance metrics.

ComEd Electric Distribution Rates

Beginning in 2024, ComEd recovers from retail customers, subject to certain exceptions, the costs it incurs to provide electric delivery services either through its electric distribution rate or other recovery mechanisms authorized by CEJA. On January 17, 2023, ComEd filed a petition with the ICC seeking approval of a MRP for 2024-2027. The MRP supports a multi-year grid plan (2024-2027 Grid Plan), also filed on January 17, covering planned investments on the electric distribution system within ComEd’s service area through 2027. Costs incurred during each year of the MRP are subject to ICC review and the plan’s revenue requirement for each year will be reconciled with the actual costs that the ICC determines are prudently and reasonably incurred for that year. The reconciliation is subject to adjustment for certain costs, including a limitation on recovery of costs that are more than 105% of certain costs in the previously approved MRP revenue requirement, absent a modification of the rate plan itself. Thus, for example, the rate adjustments necessary to reconcile 2024 revenues to ComEd’s actual 2024 costs incurred would take effect in January 2026 after the ICC’s review during 2025.

On December 14, 2023, the ICC issued a final order. The ICC rejected ComEd’s 2024-2027 Grid Plan as non-compliant with certain requirements of CEJA and required ComEd to file a revised 2024-2027 Grid Plan. In the absence of an approved 2024-2027 Grid Plan, the ICC set ComEd’s forecast revenue requirements for 2024-2027 based on ComEd's approved year-end 2022 rate base. This resulted in a total cumulative revenue requirement increase of $501 million, a $986 million total revenue reduction from the requested cumulative revenue requirement increase but remained subject to annual reconciliation in accordance with CEJA. The final order approved the process and formulas associated with the MRP reconciliation mechanisms. The ICC's December 2023 order also denied ComEd's ability to earn a return on its pension asset.

On December 22, 2023, ComEd filed an application for rehearing on several findings in the final order including the use of the 2022 year-end rate base to establish forecast revenue requirements for 2024-2027, ROE, pension asset return, and capital structure. On January 10, 2024, ComEd’s application for rehearing was denied on all issues except for the order’s use of the 2022 year-end rate base. On April 18, 2024, the ICC issued its final order on rehearing, which approved the use of the forecasted year-end 2023 rate base that resulted in increased revenue requirements for 2024-2027. These revenue requirements determined during the rehearing process established base revenue requirements until the ICC approved the Refiled 2024-2027 Grid Plan on December 19, 2024.

On January 10, 2024, ComEd filed an appeal in the Illinois Appellate Court of the issues on which rehearing was denied, including but not limited to the allowed ROE, 50% equity ratio, and denial of a return on ComEd’s pension asset. There is no deadline by when the appellate court must rule. On March 13, 2024, ComEd filed its Refiled 2024-2027 Grid Plan with supporting testimony and schedules with the ICC and subsequently on March 15, 2024, ComEd also filed a petition to adjust its MRP to authorize increased rates consistent with the Refiled 2024-2027 Grid Plan. On December 19, 2024, the ICC approved the Refiled 2024-2027 Grid Plan and adjusted the approved MRP with rates effective on January 1, 2025. The final approved MRP, as adjusted, which reflects the Refiled Grid Plan, resulted in a total cumulative revenue requirement increase of $1.045 billion over the 2024-2027 plan years and remains subject to annual reconciliations in accordance with CEJA. ComEd filed timely requests for rehearing and an appeal of the MRP order, again limited to the issues on which rehearing of the December 2023 order was denied, including the allowed ROE, 50% equity ratio, and denial of a return on ComEd's pension asset.

On January 16, 2026, ComEd filed a multi-year integrated grid plan (2028-2031 Grid Plan), seeking approval for planned investments on the electric distribution system within ComEd's service area in 2028-2031. The ICC must issue an order by December 15, 2026.

Carbon Mitigation Credit

CEJA establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. ComEd is required to purchase CMCs from participating nuclear power generating facilities between June 1, 2022 and May 31, 2027. The price to be paid for each CMC was established through a competitive bidding process that included consumer-protection measures that capped the maximum acceptable bid amount and a formula that reduces CMC prices by an energy price index, the base residual auction capacity price in the ComEd zone of PJM, and the monetized value of any federal tax credit or other subsidy if applicable. On October 31, 2025, the seller provided notification to ComEd and the IPA that it has reflected on its 2024 federal tax return $804 million of nuclear production tax credits associated with its participating nuclear power generating facilities. These amounts will be collected from the seller through an adjustment to the CMC price to be paid by ComEd and returned to customers in 2026. As of December 31, 2025, Exelon and ComEd's Consolidated Balance Sheets reflect these amounts as a receivable from the seller with an offsetting balance within the Carbon mitigation credit regulatory liability. These adjustments had no net impact on Exelon and ComEd’s Consolidated Statements of Operations and Comprehensive Income. The consumer protection measures contained in CEJA will result in net payments to ComEd ratepayers if the energy index, the capacity price and applicable federal tax credits or subsidy exceed the CMC contract price. Beginning with the June 2022 monthly billing period, ComEd began issuing credits and/or charges to its retail customers under its CMC rider, the Rider Carbon-Free Resource Adjustment (Rider CFRA). A regulatory asset or liability is recorded for the difference between ComEd's costs associated with the procurement of CMCs from participating nuclear power generating facilities and revenues received from customers. The balance of the liability as of December 31, 2025 is $670 million.

On February 2, 2024, ComEd filed a petition with the ICC to initiate the reconciliation proceeding for the costs incurred in connection with the procurement of CMC’s during the delivery year beginning June 1, 2022 and extending through May 31, 2023. While both Staff and the Administrative Law Judge's proposed order supported ComEd’s proposed reconciliation adjustment, on September 4, 2025, the ICC issued its final order rejecting the proposed reconciliation adjustment. Specifically, the order disallowed portions of the administrative costs as well as a portion of ComEd's interest costs on the balance of credit extended to customers under the applicable tariff that were not yet funded by payments from the generator. The CMC costs themselves were not disallowed. The order resulted in an immaterial impact to the financial statements and on October 3, 2025 ComEd filed its Application for Rehearing. On October 16, 2025, the ICC denied ComEd's Application. On October 17, 2025, ComEd filed its appeal with the Illinois Appellate Court for review of the ICC's order and its denial of rehearing.

Energy Efficiency

CEJA extends ComEd’s current cumulative annual energy efficiency MWh savings goals through 2040, adds expanded electrification measures to those goals, increases low-income commitments, and adds a new performance adjustment to the energy efficiency formula rate. ComEd expects its annual spend to increase through 2040 to achieve these energy efficiency MWh savings goals, which is deferred as a separate regulatory asset that is recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures.

Energy Efficiency Formula Rate (Exelon and ComEd). FEJA allows ComEd to defer energy efficiency costs (except for any voltage optimization costs which are recovered through electric distribution rates) as a separate regulatory asset that is recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd earns a return on the energy efficiency regulatory asset at a rate equal to a weighted average cost of capital, which is based on a year-end capital structure and a statutorily-based formula based on long-term treasury debt. The ROE that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd’s cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd is required to file an update to its energy efficiency formula rate on or before June 1st each year, with resulting rates effective in January of the following year. The annual update is based on projected rate year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred from the year (annual reconciliation). The approved energy efficiency formula rate also provides for revenue decoupling provisions.

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

During 2025, the ICC approved the following total increases in ComEd's requested energy efficiency revenue requirement:

Filing Date	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase[(a)]	Approved ROE	Approval Date	Rate Effective Date
May 23, 2025	$ 19	$ 19	10.21 %	November 19, 2025	January 1, 2026

(a) ComEd's 2026 approved revenue requirement reflects an increase of $24 million for the initial year revenue requirement for 2026 and a decrease of $5 million related to the annual reconciliation for 2024. The revenue requirement for 2025 provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 7.23% inclusive of an allowed ROE of 10.21%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The revenue requirement for the 2024 reconciliation year provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 7.50% inclusive of an allowed ROE of 10.75%, which includes an upward performance adjustment that increased the ROE. The performance adjustment can either increase or decrease the ROE based upon the achievement of energy efficiency savings goals. See table below for ComEd's regulatory assets associated with its energy efficiency formula rate.

Maryland Regulatory Matters

Maryland Revenue Decoupling (Exelon, BGE, PHI, Pepco, and DPL). In 1998, the MDPSC approved natural gas monthly rate adjustments for BGE and in 2007, the MDPSC approved electric monthly rate adjustments for BGE and BSAs for Pepco and DPL, all of which are decoupling mechanisms. As a result of the decoupling mechanisms, certain Operating revenues from electric and natural gas distribution at BGE and Operating revenues from electric distribution at Pepco Maryland (see also District of Columbia Revenue Decoupling below for Pepco District of Columbia) and DPL are not intended to be impacted by abnormal weather or usage per customer. For BGE, Pepco, and DPL, the decoupling mechanism eliminates the impacts of abnormal weather or customer usage by recognizing revenues based on an authorized distribution amount per customer by customer class. Operating revenues from electric and natural gas distribution at BGE and Operating revenues from electric distribution at Pepco Maryland and DPL are, however, impacted by changes in the number of customers.

EmPOWER Maryland Cost Recovery (Exelon, BGE, PHI, Pepco and DPL). On December 29, 2023, the MDPSC issued an order authorizing the next three-year program cycle for EmPOWER Maryland and approved various proposals by the program administrators to implement new energy efficiency programs for the 2024-2026 program cycle, as well as continue operating core programs. Historically, BGE, Pepco, and DPL deferred most of their energy efficiency program costs to a regulatory asset and either deferred most of their demand response program costs to a regulatory asset or capitalized them. Beginning in 2024, BGE, Pepco, and DPL began deferring less energy efficiency and demand response program costs and beginning January 1, 2026, program costs are no longer being deferred. Additionally, as part of the order, the MDPSC directed BGE, Pepco, and DPL to extend the amortization of unamortized costs as of December 31, 2023 from 5 to 7 years to mitigate customer bill impacts.

Next Generation Energy Act (Exelon, BGE, PHI, Pepco, and DPL). On May 20, 2025, the Governor of Maryland signed into law legislation that addresses several matters pertaining to electric and gas utilities, including affirming that the MDPSC may approve the use of multi-year rate plans that demonstrate customer benefits, among other things. It also prohibits utilities from filing after January 1, 2025, for the reconciliation of actuals costs and revenues to amounts approved within the multi-year plans. In the second quarter of 2025, BGE derecognized Regulatory assets of $10 million and Regulatory liabilities of $3 million for multi-year plan reconciliations that are no longer eligible to be filed. DPL also derecognized Regulatory liabilities of $0.4 million during the second quarter of 2025 for multi-year reconciliations ineligible to be filed. Multi-year plan reconciliations filed prior to January 1, 2025, remain lawful and will be resolved in their respective proceedings.

Summer and Winter Rate Mitigation (Exelon, BGE, PHI, Pepco, and DPL). As part of the passing of the Next Generation Energy Act by the Maryland General Assembly, the MDPSC issued an order on June 26, 2025, to implement the Legislative Energy Relief Refund program under which bill credits were distributed to residential customers based on their consumption of electricity supply that was subject to the renewable energy portfolio standard. On July 24, 2025, the MDPSC issued an order accepting BGE, Pepco, and DPL's proposal for the implementation of the program. As a result, BGE, Pepco, and DPL received $49 million, $21 million, and $8 million, respectively, from the MDPSC on August 6, 2025. These amounts were used to reduce residential customer account receivable balances within the third quarter of 2025. Additional disbursements from the state of

Maryland were received by BGE, Pepco, and DPL on February 3, 2026 for approximately $49 million, $21 million, and $8 million, respectively. These amounts will also be used to reduce residential customer receivables in the first quarter of 2026.

District of Columbia Regulatory Matters

District of Columbia Revenue Decoupling (Exelon, PHI, and Pepco). In 2009, the DCPSC approved a BSA, which is a decoupling mechanism. As a result of the decoupling mechanism, Operating revenues from electric distribution at Pepco District of Columbia (see also Maryland Revenue Decoupling above for Pepco Maryland) are not intended to be impacted by abnormal weather or usage per customer. The decoupling mechanism initially approved eliminated the impacts of abnormal weather or customer usage by recognizing revenues based on an authorized distribution amount per customer by customer class. Prior to 2025, operating revenues from electric distribution at Pepco District of Columbia were, impacted by changes in the number of customers. Beginning in 2025, based on modifications approved by the DCPSC, Pepco District of Columbia began recognizing revenues on an authorized distribution amount per customer class basis, and operating revenues from electric distribution have no longer been impacted by changes in the number of customers.

New Jersey Regulatory Matters

Conservation Incentive Program (CIP) (Exelon, PHI, and ACE). On September 25, 2020, ACE filed an application with the NJBPU as required to seek approval to implement a portfolio of energy efficiency programs pursuant to New Jersey’s clean energy legislation. The filing included a request to implement a CIP that would eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution revenues for most customers. The CIP compares current distribution revenues by customer class to approved target revenues established in ACE’s most recent distribution base rate case. The CIP is calculated annually and recovery is subject to certain conditions, including an earnings test and ceilings on customer rate increases.

On April 27, 2021, the NJBPU approved the settlement filed by ACE and the third parties to the proceeding. The approved settlement addresses all material aspects of ACE’s filing, including ACE’s ability to implement the CIP prospectively effective July 1, 2021. As a result of this decoupling mechanism, operating revenues are no longer intended to be impacted by abnormal weather or usage for most customers. Starting in the third quarter of 2021, ACE began recording alternative revenue program revenues for its best estimate of the distribution revenue impacts resulting from future changes in CIP rates that it believes are probable of approval by the NJBPU in accordance with this mechanism.

Termination of Energy Procurement Provisions of PPAs (Exelon, PHI, and ACE). On December 22, 2021, ACE filed a petition with the NJBPU to terminate the provisions in the PPAs to purchase electricity from two coal-powered generation facilities located in the state of New Jersey. The petition was approved by the NJBPU on March 23, 2022. Upon closing of the transaction on March 31, 2022, ACE recognized a liability of $203 million for the contract termination fee and recognized a corresponding regulatory asset of $203 million. The liability has been paid in full as of December 31, 2024.

For the year ended December 31, 2024, ACE paid $49 million of the liability, which is recorded in Changes in Other assets and liabilities in Exelon's, PHI's, and ACE's Consolidated Statements of Cash Flows.

ACE Infrastructure Investment Program Filings (Exelon, PHI, and ACE). On October 31, 2022, ACE filed with the NJBPU an IIP, called “Powering the Future”, proposing to seek recovery through a new component of ACE’s rider mechanism, totaling $379 million, over the four-year period of July 1, 2023, to June 30, 2027. The new IIP will allow ACE to invest in projects that are designed to enhance the reliability, resiliency, and safety of the service ACE provides to its customers. On June 15, 2023, ACE entered into a settlement agreement with other parties, which allows for a recovery totaling $93 million of reliability related capital investments from July 1, 2023, through June 30, 2027. ACE will have the option of seeking approval from the NJBPU to extend the end date of the IIP beyond June 30, 2027, if ACE determines an extension is necessary. On June 29, 2023, the NJBPU adopted the settlement agreement and issued an order approving the program.

Advanced Metering Infrastructure Filing (Exelon, PHI, and ACE). On August 26, 2020, ACE filed an application with the NJBPU as required to seek approval to deploy a smart energy network in alignment with New Jersey’s Energy Master Plan and Clean Energy Act. The proposal consisted of estimated costs totaling $220 million with deployment taking place over a 3-year implementation period from approximately 2021 to 2024 that involved the installation of an integrated system of smart meters for all customers accompanied by the requisite communications facilities and data management systems.

On July 14, 2021, the NJBPU approved the settlement filed by ACE and the third parties to the proceeding. The approved settlement addressed all material aspects of ACE's smart energy network deployment plan, including cost recovery of the investment costs, incremental Operating and maintenance expenses, and the unrecovered balance of existing infrastructure through future distribution rates.

New Jersey Clean Energy Legislation (Exelon, PHI, and ACE). On May 23, 2018, New Jersey enacted legislation that established and modified New Jersey's clean energy and energy efficiency programs and solar and RPS. On the same day, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements. Under the legislation, the NJBPU will issue ZECs to the qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs. ACE began collecting from retail distribution customers, through a non-bypassable charge, all costs associated with the procurement of the ZECs effective April 18, 2019.

Summer Rate Mitigation (Exelon and ACE). In response to significant increases in electric supply costs, on April 23, 2025, the NJBPU issued an order directing the State's electric public utilities to file petitions proposing distribution side measures to mitigate residential customer bill impacts during summer months. As a result, on June 18, 2025, the NJBPU approved a stipulation of settlement for ACE to issue a bill credit of $30 per residential customer for the months of July and August 2025, which was deferred to Regulatory assets. The amounts will subsequently be collected from September 2025 through February 2026 at a flat rate of $10 per residential customer. The bill credit and subsequent collections will not be subject to carrying costs. As of December 31, 2025, the Regulatory asset has a remaining balance of $10 million.

Residential Universal Bill Credit (Exelon and ACE). In an effort to further reduce the burden of increased electric supply costs, on August 13, 2025, the NJBPU issued an order to establish the RUBC, which was funded by the NJBPU. The program provided a $50 bill credit per eligible residential customer for the months of September and October 2025. ACE received $51 million from the NJBPU on September 25, 2025, which was recognized as a Regulatory liability. ACE subsequently issued all bill credits to residential customers in September and October. As of December 31, 2025, there is no Regulatory liability remaining.

Other Federal Regulatory Matters

FERC Audit (Exelon and ComEd). The Utility Registrants are subject to periodic audits and investigations by FERC. FERC's Division of Audits and Accounting initiated a nonpublic audit of ComEd in April 2021 evaluating ComEd's compliance with (1) approved terms, rates and conditions of its federally regulated service; (2) accounting requirements of the Uniform System of Accounts; (3) reporting requirements of the FERC Form 1; and (4) the requirements for record retention. The audit period extended back to January 1, 2017.

On July 27, 2023, FERC published a final audit report which included, among other things, findings and recommendations related to ComEd's methodology regarding the allocation of certain overhead costs to capitalized construction costs under FERC regulations, including a suggestion that refunds may be due to customers for amounts collected in previous years. On July 30, 2024, ComEd reached an agreement in principle on the contested overhead allocation finding. As a result of the settlement process, ComEd recorded a charge for the probable disallowance of $70 million of certain currently capitalized construction costs to operating expenses, which are not expected to be recovered in future rates. The existing loss estimate was reflected in Exelon and ComEd's financial statements as of December 31, 2024. ComEd and FERC staff jointly filed the settlement agreement with FERC for approval on February 11, 2025. The settlement was approved by FERC on April 4, 2025.

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

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

The following tables provide information about the regulatory assets and liabilities of the Registrants at December 31, 2025 and 2024:

December 31, 2025	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
AMI programs - deployment costs	$ 49	$ —	$ —	$ 8	$ 41	$ 6	$ 8	$ 27
AMI programs - legacy meters	64	4	—	1	59	19	7	33
Asset retirement obligations	193	129	22	28	14	9	4	1
COVID-19	45	—	—	2	43	42	1	—
Deferred income taxes	1,167	—	1,154	—	13	13	—	—
Deferred storm costs	182	—	75	81	26	8	1	17
Distributed generation rebates	246	246	—	—	—	—	—	—
Electric distribution formula rate annual reconciliations	20	20	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	73	73	—	—	—	—	—	—
Electric energy and natural gas costs	205	43	—	52	110	67	37	6
Energy efficiency and demand response programs	686	—	—	327	359	178	68	113
Energy efficiency costs	2,018	2,018	—	—	—	—	—	—
Fair value of long-term debt	426	—	—	—	338	—	—	—
Fair value of PHI's unamortized energy contracts	21	—	—	—	21	—	—	—
MGP remediation costs	310	283	14	13	—	—	—	—
Multi-year plan reconciliations	116	71	—	26	19	19	—	—
Pension and OPEB	2,603	—	—	—	—	—	—	—
Pension and OPEB - merger related	371	—	—	—	—	—	—	—
Removal costs	967	—	—	340	627	139	140	348
Renewable energy	131	131	—	—	—	—	—	—
Transmission formula rate annual reconciliations	61	17	14	4	26	18	8	—
Under-recovered credit loss expense	152	152	—	—	—	—	—	—
Under-recovered revenue decoupling	107	—	—	39	68	30	—	38
Universal service fund charge under-recovery - Electric	32	—	32	—	—	—	—	—
Work stoppage costs	37	—	—	—	37	—	—	37
Zero emission credit	41	41	—	—	—	—	—	—
Other	250	54	36	58	107	39	12	32
Total regulatory assets	10,573	3,282	1,347	979	1,908	587	286	652
Less: current portion	1,359	595	72	175	352	182	72	93
Total noncurrent regulatory assets	$ 9,214	$ 2,687	$ 1,275	$ 804	$ 1,556	$ 405	$ 214	$ 559

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

December 31, 2025	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Carbon mitigation credit	$ 670	$ 670	$ —	$ —	$ —	$ —	$ —	$ —
Decommissioning the Regulatory Agreement Units	4,755	4,313	442	—	—	—	—	—
Dedicated facilities charge	155	—	—	155	—	—	—	—
Deferred income taxes	2,447	1,419	—	427	601	241	232	128
Electric energy and natural gas costs	155	—	113	25	17	—	—	17
Energy efficiency and demand response programs	16	—	16	—	—	—	—	—
Fiber Refund	—	—	—	—	—	—	—	—
Multi-year plan reconciliations	13	—	—	—	13	6	7	—
Over-recovered credit loss expense	5	—	—	—	5	—	—	5
Over-recovered revenue decoupling	8	—	—	1	7	—	7	—
Removal costs	2,070	1,960	—	—	110	20	88	2
Renewable portfolio standards costs	1,611	1,611	—	—	—	—	—	—
Transmission formula rate annual reconciliations	31	—	—	4	27	—	7	20
Other	208	36	18	14	45	14	17	13
Total regulatory liabilities	12,144	10,009	589	626	825	281	358	185
Less: current portion	1,128	846	140	31	103	13	42	48
Total noncurrent regulatory liabilities	$11,016	$ 9,163	$ 449	$ 595	$ 722	$ 268	$ 316	$ 137

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

December 31, 2024	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
AMI programs - deployment costs	$ 82	$ —	$ —	$ 29	$ 53	$ 11	$ 13	$ 29
AMI programs - legacy meters	90	13	—	4	73	30	10	33
Asset retirement obligations	173	112	23	26	12	8	3	1
Carbon mitigation credit	179	179	—	—	—	—	—	—
COVID-19	59	3	—	4	52	49	3	—
Deferred income taxes	937	—	925	—	12	12	—	—
Deferred storm costs	125	—	23	73	29	8	1	20
Distributed generation rebate	171	171	—	—	—	—	—	—
Electric distribution formula rate annual reconciliations	554	554	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	98	98	—	—	—	—	—	—
Electric energy and natural gas costs	108	—	—	38	70	18	20	32
Energy efficiency and demand response programs	652	—	10	329	313	174	72	67
Energy efficiency costs	1,890	1,890	—	—	—	—	—	—
Fair value of long-term debt	457	—	—	—	362	—	—	—
Fair value of PHI's unamortized energy contracts	26	—	—	—	26	—	—	—
MGP remediation costs	307	275	18	14	—	—	—	—
Multi-year plan reconciliations	170	81	—	66	23	23	—	—
Pension and OPEB	2,382	—	—	—	—	—	—	—
Pension and OPEB - merger related	503	—	—	—	—	—	—	—
Removal costs	869	—	—	261	608	127	127	356
Renewable energy	131	131	—	—	—	—	—	—
Transmission formula rate annual reconciliations	114	20	15	30	49	37	12	—
Under-recovered credit loss expense	147	126	—	—	21	—	—	21
Under-recovered revenue decoupling	188	—	—	98	90	60	—	30
Universal service fund charge under-recovery - Electric	19	—	19	—	—	—	—	—
Zero emission credit	4	4	—	—	—	—	—	—
Other	215	64	35	23	100	46	14	14
Total regulatory assets	10,650	3,721	1,068	995	1,893	603	275	603
Less: current portion	1,940	1,159	65	207	323	157	60	101
Total noncurrent regulatory assets	$ 8,710	$ 2,562	$ 1,003	$ 788	$ 1,570	$ 446	$ 215	$ 502

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

December 31, 2024	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Decommissioning the Regulatory Agreement Units	$ 4,027	$ 3,780	$ 247	$ —	$ —	$ —	$ —	$ —
Dedicated facilities charge	143	—	—	143	—	—	—	—
Deferred income taxes	2,756	1,607	—	484	665	285	247	133
Electric energy and natural gas costs	108	12	81	—	15	8	7	—
Energy efficiency and demand response programs	1	—	1	—	—	—	—	—
Fiber Refund	16	—	16	—	—	—	—	—
Multi-year plan reconciliations	9	—	—	—	9	—	9	—
Over-recovered revenue decoupling	2	—	—	—	2	—	2	—
Removal costs	1,958	1,841	—	11	106	20	86	—
Renewable portfolio standards costs	1,369	1,369	—	—	—	—	—	—
Transmission formula rate annual reconciliations	14	—	—	—	14	—	—	14
Other	206	9	30	10	52	14	16	9
Total regulatory liabilities	10,609	8,618	375	648	863	327	367	156
Less: current portion	411	197	122	12	69	17	42	10
Total noncurrent regulatory liabilities	$ 10,198	$ 8,421	$ 253	$ 636	$ 794	$ 310	$ 325	$ 146

Descriptions of the regulatory assets and liabilities included in the tables above are summarized below, including their recovery and amortization periods.

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
AMI programs - deployment costs	Represents installation and ongoing incremental costs of new smart meters, including implementation costs at Pepco and DPL of dynamic pricing for energy usage resulting from smart meters.	BGE - 2026 Pepco - 2029 DPL - 2030 ACE - 2045	BGE, Pepco, DPL - Yes ACE - Yes, on incremental costs of new smart meters
AMI programs - legacy meters	Represents early retirement costs of legacy meters.	ComEd - 2028 BGE - 2026 Pepco - 2029 DPL - 2030 ACE - 2045	ComEd, Pepco (District of Columbia), DPL (Delaware), ACE - Yes BGE, Pepco (Maryland), DPL (Maryland) - No
Asset retirement obligations	Represents future legally required removal costs associated with existing AROs.	Over the life of the related assets.	Yes, once the removal activities have been performed
Carbon mitigation credit	Represents CMC procurement costs and credits as well as reasonable costs ComEd has incurred to implement and comply with the CMC procurement process.	2026	No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
COVID-19	Represents incremental credit losses and direct costs related to COVID-19 incurred primarily in 2020 at the Utility Registrants, partially offset by a decrease in travel costs at BGE, Pepco and DPL. Direct costs consisted primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees. This also includes under-recovered amounts due to COVID-19 that were previously deferred under Pepco's revenue decoupling program.	ComEd - 2025 BGE - 2028 PECO - 2025 Pepco (District of Columbia) - $37 million - 2034 Pepco (Maryland) - $5 million - 2029 DPL (Delaware) - $1 million - 2028	ComEd, BGE, and Pepco - Yes PECO and DPL (Delaware) - No
Decommissioning the Regulatory Agreement Units	Represents estimated excess funds at the end of decommissioning the Regulatory Agreement Units. See below regarding **Decommissioning the Regulatory Agreement Units** for additional information.	Not currently being refunded.	No
Dedicated facilities charge	Represents the timing difference between the recovery of certain transmission-related assets and their depreciable life.	Depreciable life of the related assets.	Yes

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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Deferred income taxes	Represents deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of AFUDC, and the effects of income tax rate changes, including those resulting from the TCJA.	Amounts are recoverable over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
Deferred storm costs	For Pepco, DPL, ACE, PECO and BGE, amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland, New Jersey jurisdictions and Pennsylvania.	Pepco (Maryland) - \$8 million to be determined in pending multi-year plan filed with MDPSC. DPL - 2027 ACE - \$2 million - 2026; \$15 million - 2028 PECO - \$75 million to be determined in the next distribution rate case filed with the PAPUC. BGE - \$34 million - 2028; \$47 million to be determined in the next multi-year plan filed with MDPSC.	Pepco, DPL, BGE - Yes ACE, PECO - No
Distributed generation rebates	Represents ComEd's costs recovered through the distributed generation rebate adjustment tariff and the reconciliation of the difference of the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs. Deferred distributed generation rebate costs are recovered over a 15-year period.	2039	Yes

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Electric distribution formula rate annual reconciliations	Represents under/(over)-recoveries related to electric distribution service costs recoverable through ComEd's performance-based formula rate, which was updated annually with rates effective on January 1st.	2026	Yes
Electric distribution formula rate significant one-time events	Represents deferred distribution service costs related to ComEd's significant one-time events (e.g., storm costs), which are recovered over 5 years from date of the event.	2029	Yes
Electric energy and natural gas costs	Represents under (over)-recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2026	DPL (Delaware), ACE - Yes ComEd, PECO, BGE, Pepco, DPL (Maryland) - No
Energy efficiency and demand response programs	Includes under (over)-recoveries of costs incurred related to energy efficiency programs and demand response programs and recoverable costs associated with customer direct load control and energy efficiency and conservation programs that are being recovered from customers.	PECO - 2025 BGE - 2030 Pepco, DPL - 2030 ACE - 2032	BGE, Pepco (Maryland), DPL (Maryland) - See above regarding **EmPOWER Maryland Cost Recovery** for additional information Pepco (District of Columbia) - No DPL (Delaware), ACE - Yes PECO - Yes on capital investment recovered through this mechanism
Energy efficiency costs	Represents ComEd's costs recovered through the energy efficiency formula rate tariff and the reconciliation of the difference of the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs. Deferred energy efficiency costs are recovered over the weighted average useful life of the related energy measure.	2038	Yes

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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Fair value of long-term debt	Represents the difference between the carrying value and fair value of long-term debt of BGE, recorded at Exelon, and PHI of $88 million and $338 million, respectively, as of December 31, 2025, and $95 million and $362 million, respectively, as of December 31, 2024, as of the 2016 PHI and 2012 Constellation merger dates.	Exelon - 2036 PHI - 2045	No
Fair value of PHI's unamortized energy contracts	Represents the regulatory assets recorded at Exelon and PHI offsetting the fair value adjustment related to Pepco's, DPL's, and ACE's electricity and natural gas energy supply contracts recorded at PHI as of the PHI merger date.	2036	No
Fiber Refund	Represents revenues collected from Constellation and BSC for their use of PECO's fiber assets before the end of 2021.	2025	No
MGP remediation costs	Represents environmental remediation costs for MGP sites recorded at ComEd, PECO, and BGE.	ComEd and PECO - Over the expected remediation period. See Note 16 — Commitments and Contingencies for additional information. BGE - 10 years from when the remediation spend occurs.	ComEd and PECO - No BGE - Yes
Multi-year plan reconciliations	Represents under (over)-recoveries related to electric and gas distribution multi-year plans.	ComEd - 2028 BGE - 2027 Pepco (Maryland) - $1 million related to 2023 reconciliation - 2026. $18 million related to 2024 reconciliation - to be determined in a future MDPSC order. Pepco (District of Columbia) - $6 million related to 2025 reconciliation - to be determined in a future DCPSC order. DPL (Maryland) - $7 million related to 2024 reconciliation.	ComEd - Yes BGE - No Pepco (Maryland) - No Pepco (District of Columbia) - Yes DPL (Maryland) - Yes

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Pension and OPEB	Primarily reflects the Utility Registrants' and PHI's portion of deferred costs, including unamortized actuarial losses (gains) and prior service costs (credits), associated with Exelon's pension and OPEB plans, which are recovered through customer rates once amortized through net periodic benefit cost. Also, includes the Utility Registrants' and PHI's non–service cost components capitalized in Property, plant and equipment, net on their Consolidated Balance Sheets.	The deferred costs are amortized over the plan participants' average remaining service periods subject to applicable pension and OPEB cost recognition policies. See Note 12 — Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	No
Pension and OPEB - merger related	The deferred costs established at the date of the 2012 Constellation and 2016 PHI mergers are amortized over the plan participants' average remaining service periods subject to applicable pension and OPEB cost recognition policies. The costs are recovered through customer rates once amortized through net periodic benefit cost. See Note 12 — Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	Legacy BGE - 2038 Legacy PHI - 2032	No
Removal costs	For BGE, Pepco, DPL, and ACE, the regulatory asset represents costs incurred to remove property, plant and equipment in excess of amounts received from customers through depreciation rates. For ComEd, BGE, Pepco, and DPL, the regulatory liability represents amounts received from customers through depreciation rates to cover the future non–legally required cost to remove property, plant and equipment, which reduces rate base for ratemaking purposes.	BGE, Pepco, DPL, and ACE - Asset is generally recovered over the life of the underlying assets. ComEd, BGE, Pepco, DPL, and ACE - Liability is reduced as costs are incurred.	Yes
Renewable energy	Represents the change in fair value of ComEd's 20-year floating-to-fixed long-term renewable energy swap contracts.	2032	No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Renewable portfolio standards costs	Represents an overcollection of funds from both ComEd customers and alternative retail electricity suppliers to be spent on future renewable energy procurements.	$1,535 million to be determined in pending ICC annual reconciliation for the Renewable Energy Adjustment rider. $76 million to be determined based on the LTRRPP developed by the IPA.	No
Transmission formula rate annual reconciliations	Represents under (over)-recoveries related to transmission service costs recoverable through the Utility Registrants' FERC formula rates, which are updated annually with rates effective each June 1st.	2027	Yes
Under (over) - recovered revenue decoupling	Represents electric and / or gas distribution costs recoverable from or refundable to customers under decoupling mechanisms.	BGE - 2026 Pepco (Maryland) - $4 million - 2026 Pepco (District of Columbia) - $26 million - 2028 DPL - 2025 ACE - 2026	BGE, Pepco, DPL, ACE - No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Under (over) - recovered credit loss expense	For ComEd and ACE, amounts represent the difference between annual credit loss expense and revenues collected in rates through ICC and NJBPU-approved riders. The difference between net credit loss expense and revenues collected through the rider each calendar year for ComEd is recovered over a twelve-month period beginning in June of the following calendar year. ACE intends to recover from or refund to customers June through May of each respective year, subject to approval of the NJBPU.	ComEd - 2026 ACE - To be determined in the annual Societal Benefits Rider filing with NJBPU.	No
Universal service fund charge under-recovery - Electric	Represents under-recovery of electric supply and distribution revenue shortfalls net of base rate recovery related to PECO's Universal Service programs, which are designed to provide affordable bills for electric service to low-income, residential customers based on individual household needs.	PECO - To be determined in the annual adjustment and reconciliation as approved by the PAPUC.	No
Work stoppage costs	Represents work stoppage costs incurred by ACE.	2030	No
Zero emission credit	Represents ZEC procurement costs and any reasonable costs ComEd has incurred to implement and comply with the ZEC procurement process.	Over 9 months starting with the September billing period and ending with the following May billing period.	No

Decommissioning the Regulatory Agreement Units

The regulatory agreements with the ICC and PAPUC dictate obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total.

For the former PECO units, given the symmetric settlement provisions that allow for continued recovery of decommissioning costs from PECO customers in the event of a shortfall and the obligation for Constellation to ultimately return excess funds to PECO customers (on an aggregate basis for all seven units), decommissioning-related activities result in an adjustment to the Receivable related to Regulatory Agreement Units and an equal adjustment to the regulatory liabilities or regulatory assets at PECO.

For the former ComEd units, given no further recovery from ComEd customers is permitted and Constellation retains an obligation to ultimately return excess funds to ComEd customers (on a unit-by-unit basis), to the extent excess funds are expected for each unit, decommissioning-related activities result in an adjustment to the Receivable related to Regulatory Agreement Units and an equal adjustment to the regulatory liabilities at ComEd. However, given the asymmetric settlement provision that does not allow for continued recovery from ComEd customers in the event of a shortfall, recognition of a regulatory asset at ComEd is not permissible.

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

Capitalized Ratemaking Amounts Not Recognized

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders’ investment that are not recognized for financial reporting purposes in the Registrants' Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to the Utility Registrants' customers. PECO had no related amounts at December 31, 2025 and December 31, 2024

	Exelon	ComEd[(a)]	BGE[(b)]	PHI	Pepco[(c)]	DPL[(d)]	ACE[(e)]
December 31, 2025	$ 98	$ 12	$ 47	$ 39	$ 22	$ 1	$ 16
December 31, 2024	$ 117	$ 46	$ 16	$ 55	$ 40	$ 1	$ 14

(a) For the year ended December 31, 2025, reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its electric distribution rates and distributed generation regulatory assets. For the year ended December 31, 2024, reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its electric distribution rates and formula rates regulatory assets.
(b) BGE's amount capitalized for ratemaking purposes primarily relates to earnings on shareholders' investment on AMI programs and investments in rate base included in the multi-year plan reconciliations.
(c) Pepco's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on AMI programs, Energy efficiency and demand response programs, COVID-19 costs, investments in rate base and revenues included in the multi-year plan reconciliations, and a portion of Pepco District of Columbia's revenue decoupling.
(d) DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on AMI programs and Energy efficiency and demand response programs.
(e) ACE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on AMI programs.

3. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. The primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services. The performance obligations, revenue recognition, and payment terms associated with these sources of revenue are further discussed in the table below. There are no significant financing components for these sources of revenue and no variable consideration.

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

Revenue Source	Description	Performance Obligation	Timing of Revenue Recognition	Payment Terms
Regulated Electric and Gas Tariff Sales	Sales of electricity and electricity distribution services (the Utility Registrants) and natural gas and gas distribution services (PECO, BGE, and DPL) to residential, commercial, industrial, and governmental customers through regulated tariff rates approved by state regulatory commissions.	Delivery of electricity and/or natural gas.	Over time (each day) as the electricity and/or natural gas is delivered to customers. Tariff sales are generally considered daily contracts as customers can discontinue service at any time. (a)	Within the month following delivery of the electricity or natural gas to the customer.
Regulated Transmission Services	The Utility Registrants provide open access to their transmission facilities to PJM, which directs and controls the operation of these transmission facilities and accordingly compensates the Utility Registrants pursuant to filed tariffs at cost-based rates approved by FERC.	Various including (i) Network Integration Transmission Services (NITS), (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid.	Over time utilizing output methods to measure progress towards completion. (b)	Paid weekly by PJM.

(a) Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While the Utility Registrants are required under state legislation to bill their customers for the supply and distribution of electricity and/or natural gas, they recognize revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.
(b) Passage of time is used for NITS and access to the wholesale grid and MWhs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services.

The Utility Registrants do not incur any material costs to obtain or fulfill contracts with customers.

Contract Liabilities

The Registrants record contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. The Registrants record contract liabilities in Other current liabilities and Other noncurrent liabilities in the Registrants' Consolidated Balance Sheets.

In July 2020, Pepco, DPL, and ACE entered into a collaborative arrangement with an unrelated communications-infrastructure owner involving the sale of an undivided interest in certain transmission tower attachment agreements and the transfer of management rights, as further described in Note 4 — Revenue from Contracts with Customers of the 2024 Form 10-K. The Companies received additional consideration in 2023 related to an amendment of the payment options under the arrangement. Contract liabilities associated with the original arrangement and the 2023 amendment are being recognized as Electric operating revenues over 35-year and 31-year periods, respectively.

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

The following table provides a rollforward of the contract liabilities reflected in Exelon's, PHI's, Pepco's, DPL's, and ACE'S Consolidated Balance Sheets. As of December 31, 2025, 2024, and 2023, ComEd's, PECO's, and BGE's contract liabilities were not material.

	Exelon[(a)]	PHI[(a)]	Pepco[(a)]	DPL[(a)]	ACE[(a)]
Balance at December 31, 2023	$ 133	$ 133	$ 107	$ 13	$ 13
Revenues recognized	(6)	(6)	(6)	—	—
Balance at December 31, 2024	$ 127	$ 127	$ 101	$ 13	$ 13
Revenues recognized	(8)	(8)	(6)	(1)	(1)
Balance at December 31, 2025	$ 119	$ 119	$ 95	$ 12	$ 12

(a) Revenues recognized in the years ended December 31, 2025 and 2024, were included in the contract liabilities at December 31, 2024 and 2023, respectively.

Transaction Price Allocated to Remaining Performance Obligations

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of December 31, 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 the Utility Registrants' gas and electric tariff sales contracts and transmission revenue contracts as they generally have an original expected duration of one year or less and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure.

Year	Exelon	PHI	Pepco	DPL	ACE
2026	$ 5	$ 5	$ 5	$ —	$ —
2027	6	6	5	1	—
2028	6	6	5	—	1
2029	7	7	6	1	—
2030 and thereafter	95	95	74	10	11
Total	$ 119	$ 119	$ 95	$ 12	$ 12

Revenue Disaggregation

The Registrants disaggregate 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 4 — Segment Information for the presentation of the Registrant's revenue disaggregation.

4. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the CODMs in deciding how to evaluate performance and allocate resources at each of the Registrants. The Chief Executive Officer is the CODM for Exelon. For PHI and each of the Utility Registrants, CODM responsibilities are shared by Exelon's Chief Operating Officer and the Utility Registrant's Chief Executive Officer.

Exelon has six reportable segments, which include ComEd, PECO, BGE, and PHI's three reportable segments consisting of Pepco, DPL, and ACE. ComEd, PECO, BGE, Pepco, DPL, and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL, and ACE's CODMs rely on a variety of business considerations, including net income, in evaluating segment performance, determining reinvestment of profits, and establishing the amounts of dividend distributions.

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

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2025, 2024, and 2023 is as follows:

	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Operating revenues[b]:							
2025							
Electric revenues	$ 7,267	$ 3,827	$ 4,007	$ 6,894	$ —	$ (36)	$ 21,959
Natural gas revenues	—	857	1,215	231	—	(4)	2,299
Shared service and other revenues	—	—	—	10	1,900	(1,910)	—
Total operating revenues	$ 7,267	$ 4,684	$ 5,222	$ 7,135	$ 1,900	$ (1,950)	$ 24,258
2024							
Electric revenues	$ 8,219	$ 3,325	$ 3,436	$ 6,258	$ —	$ (22)	$ 21,216
Natural gas revenues	—	648	990	180	—	(6)	1,812
Shared service and other revenues	—	—	—	10	1,865	(1,875)	—
Total operating revenues	$ 8,219	$ 3,973	$ 4,426	$ 6,448	$ 1,865	$ (1,903)	$ 23,028
2023							
Electric revenues	$ 7,844	$ 3,202	$ 3,109	$ 5,812	$ —	$ (51)	$ 19,916
Natural gas revenues	—	692	918	205	—	(4)	1,811
Shared service and other revenues	—	—	—	9	1,759	(1,768)	—
Total operating revenues	$ 7,844	$ 3,894	$ 4,027	$ 6,026	$ 1,759	$ (1,823)	$ 21,727
Less:							
Purchased power							
2025	$ 1,782	$ 1,436	$ 1,890	$ 2,836	$ —	$ —	$ 7,944
2024	3,042	1,265	1,460	2,447	—	—	8,214
2023	2,816	1,270	1,311	2,250	—	1	7,648
Purchased fuel							
2025	$ —	$ 297	$ 331	$ 95	$ —	$ —	$ 723
2024	—	212	191	66	—	—	469
2023	—	274	220	98	—	1	593
Operating and maintenance							
2025	$ 1,306	$ 946	$ 815	$ 1,123	$ 1,840	$ (853)	$ 5,177
2024	1,284	875	790	1,046	1,733	(788)	4,940
2023	1,096	786	520	1,110	1,861	(814)	4,559
Operating and maintenance from affiliates							
2025	$ 404	$ 249	$ 251	$ 204	$ 43	$ (1,151)	$ —
2024	419	245	246	204	41	(1,155)	—
2023	354	217	221	179	37	(1,008)	—
Depreciation and amortization							
2025	$ 1,560	$ 454	$ 632	$ 935	$ 59	$ —	$ 3,640
2024	1,514	428	638	947	67	—	3,594
2023	1,403	397	654	990	62	—	3,506
Taxes other than income taxes							
2025	$ 409	$ 240	$ 370	$ 568	$ 42	$ —	$ 1,629
2024	376	218	345	528	37	—	1,504
2023	369	202	319	487	31	—	1,408

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
(Gain) loss on sale of assets and businesses							
2025	$ —	$ —	$ —	$ (3)	$ —	$ —	$ (3)
2024	(5)	(4)	—	1	(4)	—	(12)
2023	—	—	—	(9)	(1)	—	(10)
Interest expense, net[c]							
2025	$ 517	$ 249	$ 247	$ 408	$ 681	$ —	$ 2,102
2024	487	221	216	373	592	—	1,889
2023	464	192	182	323	545	(2)	1,704
Interest expense to affiliates, net[c]							
2025	$ 13	$ 11	$ —	$ 3	$ (2)	$ —	$ 25
2024	14	11	—	3	(3)	—	25
2023	13	9	—	—	1	2	25
Other, net							
2025	$ (132)	$ (41)	$ (51)	$ (72)	$ (28)	$ 54	$ (270)
2024	(94)	(37)	(36)	(97)	(38)	40	(262)
2023	(75)	(36)	(18)	(108)	(190)	19	(408)
Income taxes							
2025	$ 261	$ 29	$ 159	$ 239	$ (165)	$ —	$ 523
2024	116	(12)	49	189	(135)	—	207
2023	314	20	133	116	(207)	(2)	374
Net income (loss)							
2025	$ 1,147	$ 814	$ 578	$ 799	$ (570)	$ —	$ 2,768
2024	1,066	551	527	741	(425)	—	2,460
2023	1,090	563	485	590	(380)	(20)	2,328
Supplemental segment information							
Intersegment revenues[d]							
2025	$ 21	$ 12	$ 8	$ 10	$ 1,890	$ (1,941)	$ —
2024	8	10	10	10	1,855	(1,893)	—
2023	16	9	9	9	1,750	(1,793)	—
Capital expenditures							
2025	$ 2,899	$ 1,867	$ 1,657	$ 2,056	$ 50	$ —	$ 8,529
2024	2,195	1,553	1,420	1,863	66	—	7,097
2023	2,576	1,426	1,367	1,988	54	—	7,411
Total assets							
2025	$ 48,285	$ 19,362	$17,184	$ 29,715	$ 6,170	$ (4,146)	$116,570
2024	44,750	17,123	15,542	28,297	6,012	(3,940)	107,784

(a) Other primarily includes Exelon's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in Taxes other than income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 20 — Supplemental Financial Information for additional information on total utility taxes.
(c) Interest expense, net and Interest expense to affiliates, net are primarily inclusive of Interest expense, which is partially offset by an immaterial amount of interest income.
(d) See Note 21 — Related Party Transactions for additional information on intersegment revenues.

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

PHI:

	Pepco	DPL	ACE	Other[(a)]	Intersegment Eliminations	PHI
Operating revenues[(b)]:						
2025						
Electric revenues	$ 3,454	$ 1,740	$ 1,718	$ —	$ (18)	$ 6,894
Natural gas revenues	—	231	—	—	—	231
Shared service and other revenues	—	—	—	424	(414)	10
Total operating revenues	$ 3,454	$ 1,971	$ 1,718	$ 424	$ (432)	$ 7,135
2024						
Electric revenues	$ 3,039	$ 1,607	$ 1,628	$ —	$ (16)	$ 6,258
Natural gas revenues	—	180	—	—	—	180
Shared service and other revenues	—	—	—	438	(428)	10
Total operating revenues	$ 3,039	$ 1,787	$ 1,628	$ 438	$ (444)	$ 6,448
2023						
Electric revenues	$ 2,824	$ 1,483	$ 1,522	$ 1	$ (18)	$ 5,812
Natural gas revenues	—	205	—	—	—	205
Shared service and other revenues	—	—	—	422	(413)	9
Total operating revenues	$ 2,824	$ 1,688	$ 1,522	$ 423	$ (431)	$ 6,026
Less:						
Purchased power						
2025	$ 1,262	$ 766	$ 808	$ —	$ —	$ 2,836
2024	1,055	694	698	—	—	2,447
2023	974	639	637	—	—	2,250
Purchased fuel						
2025	$ —	$ 95	$ —	$ —	$ —	$ 95
2024	—	66	—	—	—	66
2023	—	98	—	—	—	98
Operating and maintenance						
2025	$ 379	$ 213	$ 173	$ 358	$ —	$ 1,123
2024	283	196	206	361	—	1,046
2023	336	193	233	348	—	1,110
Operating and maintenance from affiliates						
2025	$ 246	$ 178	$ 155	$ 57	$ (432)	$ 204
2024	251	181	162	54	(444)	204
2023	236	171	153	50	(431)	179
Depreciation and amortization						
2025	$ 433	$ 252	$ 248	$ 2	$ —	$ 935
2024	407	245	278	17	—	947

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

	Pepco	DPL	ACE	Other[(a)]	Intersegment Eliminations	PHI
2023	441	244	283	22	—	990
Taxes other than income taxes						
2025	$ 455	$ 88	$ 9	$ 16	$ —	$ 568
2024	424	79	9	16	—	528
2023	390	75	8	14	—	487
(Gain) loss on sale of assets and businesses						
2025	$ (1)	$ —	$ (2)	$ —	$ —	$ (3)
2024	1	—	—	—	—	1
2023	(9)	—	—	—	—	(9)
Interest expense, net[(c)]						
2025	$ 214	$ 102	$ 82	$ 10	$ —	$ 408
2024	195	94	74	10	—	373
2023	165	74	72	12	—	323
Interest expense to affiliates, net[(c)]						
2025	$ —	$ —	$ —	$ 3	$ —	$ 3
2024	(3)	(1)	5	2	—	3
2023	—	—	—	—	—	—
Other, net						
2025	$ (41)	$ (16)	$ (10)	$ (5)	$ —	$ (72)
2024	(54)	(25)	(14)	(4)	—	(97)
2023	(66)	(18)	(20)	(4)	—	(108)
Income taxes						
2025	$ 106	$ 69	$ 67	$ (3)	$ —	$ 239
2024	90	49	55	(5)	—	189
2023	51	35	36	(6)	—	116
Net income (loss) from continuing operations						
2025	$ 401	$ 224	$ 188	$ (14)	$ —	$ 799
2024	390	209	155	(13)	—	741
2023	306	177	120	(13)	—	590
Supplemental segment information						
Intersegment revenues[(d)]						
2025	$ 6	$ 9	$ 4	$ 423	$ (432)	$ 10
2024	7	7	2	438	(444)	10
2023	9	8	2	422	(432)	9
Capital expenditures						
2025	$ 957	$ 534	$ 390	$ 175	$ —	$ 2,056
2024	929	556	373	5	—	1,863
2023	957	562	460	9	—	1,988
Total assets						
2025	$ 12,728	$ 6,789	$ 5,632	$ 4,602	$ (36)	$ 29,715
2024	12,000	6,421	5,349	4,567	(40)	28,297

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in Taxes other than income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 20 — Supplemental Financial Information for additional information on total utility taxes.
(c) Interest expense, net is primarily inclusive of Interest expense, which is partially offset by an immaterial amount of Interest income.
(d) Includes intersegment revenues with ComEd, PECO, and BGE, which are eliminated at Exelon.

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

Electric and Gas Revenue by Customer Class (Utility Registrants):

The following tables disaggregate the Registrants' revenues 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. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of electric sales and natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with the Utility Registrants, but exclude any intercompany revenues.

	2025						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Electric revenues							
Residential	$ 4,203	$ 2,494	$ 2,503	$ 3,733	$ 1,669	$ 1,049	$ 1,015
Small commercial & industrial	2,072	627	414	722	205	264	253
Large commercial & industrial	593	339	603	1,514	1,212	122	180
Public authorities & electric railroads	47	34	33	73	39	16	18
Other[(a)]	907	312	476	917	372	303	250
Total electric revenues[(b)]	$ 7,822	$ 3,806	$ 4,029	$ 6,959	$ 3,497	$ 1,754	$ 1,716
Natural gas revenues							
Residential	$ —	$ 593	$ 823	$ 139	$ —	$ 139	$ —
Small commercial & industrial	—	206	140	55	—	55	—
Large commercial & industrial	—	—	248	7	—	7	—
Transportation	—	37	—	19	—	19	—
Other[(c)]	—	19	51	11	—	11	—
Total natural gas revenues[(d)]	$ —	$ 855	$ 1,262	$ 231	$ —	$ 231	$ —
Total revenues from contracts with customers	$ 7,822	$ 4,661	$ 5,291	$ 7,190	$ 3,497	$ 1,985	$ 1,716
Other revenues							
Revenues from alternative revenue programs	$ (596)	$ —	$ (87)	$ (63)	$ (49)	$ (16)	$ 2
Other electric revenues[(e)]	41	21	14	8	6	2	—
Other natural gas revenues[(e)]	—	2	4	—	—	—	—
Total other revenues	$ (555)	$ 23	$ (69)	$ (55)	$ (43)	$ (14)	$ 2
Total revenues for reportable segments	$ 7,267	$ 4,684	$ 5,222	$ 7,135	$ 3,454	$ 1,971	$ 1,718

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

	2024						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Electric revenues							
Residential	$ 3,809	$ 2,169	$ 2,038	$ 3,256	$ 1,413	$ 943	$ 900
Small commercial & industrial	2,259	547	360	681	184	253	244
Large commercial & industrial	1,145	261	557	1,372	1,053	123	196
Public authorities & electric railroads	60	29	31	74	37	17	20
Other[(a)]	1,080	296	414	871	327	270	280
Total electric revenues[(b)]	$ 8,353	$ 3,302	$ 3,400	$ 6,254	$ 3,014	$ 1,606	$ 1,640
Natural gas revenues							
Residential	$ —	$ 445	$ 625	$ 108	$ —	$ 108	$ —
Small commercial & industrial	—	157	110	43	—	43	—
Large commercial & industrial	—	—	204	5	—	5	—
Transportation	—	28	—	17	—	17	—
Other[(c)]	—	16	18	7	—	7	—
Total natural gas revenues[(d)]	$ —	$ 646	$ 957	$ 180	$ —	$ 180	$ —
Total revenues from contracts with customers	$ 8,353	$ 3,948	$ 4,357	$ 6,434	$ 3,014	$ 1,786	$ 1,640
Other revenues							
Revenues from alternative revenue programs	$ (151)	$ 6	$ 52	$ 1	$ 15	$ (2)	$ (12)
Other electric revenues[(e)]	17	17	14	13	10	3	—
Other natural gas revenues[(e)]	—	2	3	—	—	—	—
Total other revenues	$ (134)	$ 25	$ 69	$ 14	$ 25	$ 1	$ (12)
Total revenues for reportable segments	$ 8,219	$ 3,973	$ 4,426	$ 6,448	$ 3,039	$ 1,787	$ 1,628

	2023						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Electric revenues							
Residential	$ 3,565	$ 2,090	$ 1,765	$ 2,845	$ 1,236	$ 827	$ 782
Small commercial & industrial	1,857	526	331	651	176	246	229
Large commercial & industrial	824	249	528	1,420	1,087	126	207
Public authorities & electric railroads	51	30	29	67	34	16	17
Other[(a)]	965	298	402	760	258	250	260
Total electric revenues[(b)]	$ 7,262	$ 3,193	$ 3,055	$ 5,743	$ 2,791	$ 1,465	$ 1,495
Natural gas revenues							
Residential	$ —	$ 473	$ 568	$ 122	$ —	$ 122	$ —
Small commercial & industrial	—	172	100	53	—	53	—
Large commercial & industrial	—	1	161	4	—	4	—
Transportation	—	27	—	16	—	16	—
Other[(c)]	—	17	37	10	—	10	—
Total natural gas revenues[(d)]	$ —	$ 690	$ 866	$ 205	$ —	$ 205	$ —
Total revenues from contracts with customers	$ 7,262	$ 3,883	$ 3,921	$ 5,948	$ 2,791	$ 1,670	$ 1,495
Other revenues							
Revenues from alternative revenue programs	$ 556	$ (7)	$ 84	$ 64	$ 22	$ 15	$ 27
Other electric revenues[(e)]	26	16	16	14	11	3	—
Other natural gas revenues[(e)]	—	2	6	—	—	—	—
Total other revenues	$ 582	$ 11	$ 106	$ 78	$ 33	$ 18	$ 27
Total revenues for reportable segments	$ 7,844	$ 3,894	$ 4,027	$ 6,026	$ 2,824	$ 1,688	$ 1,522

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

(a) Includes transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates in 2025, 2024, and 2023 respectively of:
- $21 million, $8 million, and $16 million at ComEd
- $9 million, $7 million, and $7 million at PECO
- $6 million, $7 million, and $6 million at BGE
- $10 million, $10 million, and $9 million at PHI
- $6 million, $7 million, and $9 million at Pepco
- $9 million, $7 million, and $8 million at DPL
- $4 million, $2 million, and $2 million at ACE

(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates in 2025, 2024, and 2023 respectively of:
- $3 million, $3 million, and $2 million at PECO
- $2 million, $3 million, and $3 million at BGE

(e) Includes late payment charge revenues.

5. Accounts Receivable (All Registrants)

Allowance for Credit Losses on Accounts Receivable

The following tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Year Ended December 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2024	$ 406	$ 109	$ 133	$ 56	$ 108	$ 59	$ 17	$ 32
Plus: Current period provision for expected credit losses[(a)(b)(c)]	289	90	91	43	65	41	16	8
Less: Write-offs[(d)(e)], net of recoveries[(f)(g)]	260	84	87	31	58	31	14	13
Balance at December 31, 2025	$ 435	$ 115	$ 137	$ 68	$ 115	$ 69	$ 19	$ 27

	Year Ended December 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2023	$ 317	$ 69	$ 95	$ 46	$ 107	$ 52	$ 19	$ 36
Plus: Current period provision for expected credit losses	248	78	72	37	61	39	10	12
Less: Write-offs, net of recoveries	159	38	34	27	60	32	12	16
Balance at December 31, 2024	$ 406	$ 109	$ 133	$ 56	$ 108	$ 59	$ 17	$ 32

(a) For ComEd, the increase is primarily a result of increased aging of receivables.
(b) For PECO, BGE, and DPL, the increase is primarily a result of increased receivable balances.
(c) For ACE, the decrease is primarily a result of decreased aging of receivables.
(d) For ComEd, PECO, and DPL, the increase is primarily a result of increased disconnection activities.
(e) For ACE, the decrease is primarily a result of decreased disconnection activities.
(f) Recoveries were not material to ComEd, BGE, Pepco, DPL, and ACE.
(g) For PECO, the increase in recoveries collected is primarily a result of increased customer repayments.

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

The following tables present the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	Year Ended December 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2024	$ 107	$ 34	$ 18	$ 6	$ 49	$ 27	$ 9	$ 13
Plus: Current period provision (benefit) for expected credit losses[(a)(b)]	24	10	14	(2)	2	(1)	1	2
Less: Write-offs[(c)(d)], net of recoveries[(e)]	37	21	14	—	2	—	—	2
Balance at December 31, 2025	$ 94	$ 23	$ 18	$ 4	$ 49	$ 26	$ 10	$ 13

	Year Ended December 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2023	$ 82	$ 17	$ 8	$ 7	$ 50	$ 28	$ 8	$ 14
Plus: Current period provision (benefit) for expected credit losses	45	21	15	6	3	(1)	1	3
Less: Write-offs, net of recoveries	20	4	5	7	4	—	—	4
Balance at December 31, 2024	$ 107	$ 34	$ 18	$ 6	$ 49	$ 27	$ 9	$ 13

(a) For ComEd, the decrease is primarily a result of decreased aging of receivables.
(b) For BGE, the decrease is primarily a result of decreased receivable balances.
(c) For ComEd and PECO, the increase is primarily a result of increased disconnection activities.
(d) For BGE and ACE, the decrease is primarily a result of decreased disconnection activities.
(e) Recoveries were not material to the Registrants.

Unbilled Customer Revenue

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets as of December 31, 2025 and 2024.

	Unbilled customer revenues[(a)]							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2025	$ 1,231	$ 301	$ 278	$ 325	$ 327	$ 155	$ 100	$ 72
December 31, 2024	1,114	335	254	257	268	121	76	71

(a) Unbilled customer revenues are classified in Customer accounts receivable, net in the Registrants' Consolidated Balance Sheets.

Other Purchases of Customer and Other Accounts Receivables

For the twelve months ended December 31, 2025 and 2024, the Utility Registrants were required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, Delaware, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participated in the utilities' consolidated billing. The following table presents the total receivables purchased.

	Total receivables purchased							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Year ended December 31, 2025	$ 4,341	$ 1,066	$ 1,257	$ 700	$ 1,318	$ 823	$ 263	$ 232
Year ended December 31, 2024	4,128	964	1,111	778	1,275	799	252	224

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

6. Property, Plant, and Equipment (All Registrants)

The following tables present a summary of property, plant, and equipment by asset category at December 31, 2025 and 2024:

Asset Category	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2025								
Electric—transmission and distribution	$ 84,282	$ 38,370	$ 13,314	$ 11,687	$ 22,614	$ 14,420	$ 6,423	$ 6,247
Gas—transportation and distribution	10,499	—	4,649	5,190	940	—	1,094	—
Common—electric and gas[(a)]	2,954	—	1,135	1,430	460	—	251	—
Construction work in progress	5,755	1,997	836	1,236	1,629	1,087	290	238
Other property, plant, and equipment[(b)]	908	179	119	76	84	24	38	27
Total property, plant, and equipment	104,398	40,546	20,053	19,619	25,727	15,531	8,096	6,512
Less: accumulated depreciation	20,080	8,291	4,131	5,234	4,350	4,784	2,241	1,956
Property, plant, and equipment, net	$ 84,318	$ 32,255	$ 15,922	$ 14,385	$ 21,377	$ 10,747	$ 5,855	$ 4,556
December 31, 2024								
Electric—transmission and distribution	$ 79,283	$ 36,493	$ 12,234	$ 11,131	$ 21,130	$ 13,593	$ 6,086	$ 5,947
Gas—transportation and distribution	9,599	—	4,247	4,796	821	—	976	—
Common—electric and gas	2,630	—	1,064	1,385	272	—	241	—
Construction work in progress	4,306	1,219	813	779	1,472	1,002	275	187
Other property, plant and equipment[(a)]	809	118	76	48	86	24	37	30
Total property, plant and equipment	96,627	37,830	18,434	18,139	23,781	14,619	7,615	6,164
Less: accumulated depreciation	18,445	7,619	4,042	5,005	3,728	4,522	2,075	1,798
Property, plant, and equipment, net	$ 78,182	$ 30,211	$ 14,392	$ 13,134	$ 20,053	$ 10,097	$ 5,540	$ 4,366

(a) On April 15, 2025, PHI purchased an office building and land in the District of Columbia for $177 million which it had been leasing. The lease was terminated on April 15, 2025, in conjunction with the purchase (See Note 9 — Leases for additional information).
(b) Primarily composed of land and non-utility property.

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

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

	Average Service Life (years)							
Asset Category	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Electric - transmission and distribution	5-80	5-80	5-70	5-80	5-75	5-75	5-75	5-75
Gas - transportation and distribution	5-80	N/A	5-80	5-80	5-75	N/A	5-75	N/A
Common - electric and gas	4-75	N/A	5-53	4-45	5-75	N/A	5-75	N/A
Other property, plant, and equipment	4-61	28-50	50	20-50	10-43	10-33	10-43	10-43

The following table presents the annual depreciation rates for each asset category.

	Annual Depreciation Rates							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
December 31, 2025								
Electric—transmission and distribution	2.85%	3.07%	2.33%	2.56%	2.89%	2.51%	3.09%	3.62%
Gas—transportation and distribution	2.08%	N/A	1.94%	2.37%	1.29%	N/A	1.29%	N/A
Common—electric and gas	6.14%	N/A	6.37%	7.08%	2.88%	N/A	5.53%	N/A
December 31, 2024								
Electric—transmission and distribution	2.83%	3.06%	2.30%	2.55%	2.87%	2.49%	2.99%	3.41%
Gas—transportation and distribution	2.12%	N/A	1.96%	2.42%	1.38%	N/A	1.38%	N/A
Common—electric and gas	7.00%	N/A	6.73%	7.81%	4.82%	N/A	6.14%	N/A
December 31, 2023								
Electric—transmission and distribution	2.90%	3.02%	2.30%	2.89%	3.03%	2.51%	3.29%	3.66%
Gas—transportation and distribution	2.15%	N/A	1.85%	2.56%	1.44%	N/A	1.44%	N/A
Common—electric and gas	7.77%	N/A	6.87%	8.68%	7.18%	N/A	8.79%	N/A

AFUDC

The following table summarizes credits to AFUDC by year:

	For the Years Ended December 31,		
	2025	**2024**	**2023**
Exelon	$ 275	$ 251	$ 256
ComEd	94	75	72
PECO	54	48	46
BGE	58	39	25
PHI	69	89	113
Pepco	49	62	85
DPL	11	19	16
ACE	8	8	12

See Note 1 — Significant Accounting Policies for additional information regarding property, plant and equipment policies. See Note 14 — Debt and Credit Agreements for additional information regarding Exelon’s, ComEd’s, PECO's, Pepco's, DPL's, and ACE’s property, plant and equipment subject to mortgage liens.

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

7. Jointly Owned Electric Utility Plant (Exelon, PECO, PHI, DPL, and ACE)

PECO's, DPL's, and ACE's material undivided ownership interests in transmission facilities jointly owned with non-affiliated utilities as of December 31, 2025 and 2024 were as follows:

	Transmission
	NJ/DE[(a)]
Operator	**PSEG/DPL**
Ownership interest	various
Exelon’s share at December 31, 2025:	
Plant in service	$ 119
Accumulated depreciation	55
Construction work in progress	16
Exelon’s share at December 31, 2024:	
Plant in service	$ 105
Accumulated depreciation	57
Construction work in progress	4

(a) PECO, DPL, and ACE own a 42.55%, 1%, and 13.9% share, respectively, in 151.3 miles of 500kV lines located in New Jersey and in the Salem substation. PECO, DPL, and ACE also own a 42.55%, 7.45%, and 7.45% share, respectively, in 2.5 miles of 500kV line located over the Delaware River. ACE also has a 21.78% share in a 500kV New Freedom Switching substation.

Certain facilities are fully owned by Exelon through its 100% ownership in PECO, DPL, and ACE. These facilities are operated by Exelon Registrants. PECO's, DPL's, and ACE's material undivided ownership interests in Exelon owned facilities as of December 31, 2025 and 2024 were as follows:

	PECO	PHI	DPL	ACE
Ownership interest	56 %	44 %	27 %	17 %
Registrant's share at December 31, 2025:				
Plant in service	$ 82	$ 73	$ 45	$ 28
Accumulated depreciation	4	6	4	2
Construction work in progress	—	—	—	—
Registrant's share at December 31, 2024:				
Plant in service	$ 84	$ 72	$ 44	$ 28
Accumulated depreciation	2	3	3	—
Construction work in progress	—	—	—	—

PECO's, DPL's, and ACE's undivided ownership interests presented in the tables above are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. PECO's, DPL's, and ACE's share of direct expenses of the jointly owned plants are included in Operating and maintenance expenses in Exelon's, PECO's, PHI's, DPL's, and ACE's Consolidated Statements of Operations and Comprehensive Income.

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

8. Asset Retirement Obligations (All Registrants)

The Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1 — Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the AROs reflected in the Registrants' Consolidated Balance Sheets from December 31, 2023 to December 31, 2025:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
AROs at December 31, 2023	$ 269	$ 150	$ 27	$ 32	$ 56	$ 37	$ 13	$ 6
Revisions in estimates of cash flows	26	12	1	3	10	10	—	—
Accretion expense[(a)]	11	7	1	1	2	2	—	—
Payments	(2)	(1)	(1)	—	—	—	—	—
AROs at December 31, 2024	$ 304	$ 168	$ 28	$ 36	$ 68	$ 49	$ 13	$ 6
Revisions in estimates of cash flows	15	19	—	(1)	(3)	(1)	(1)	(1)
Accretion expense[(a)]	13	8	1	1	3	3	—	—
Payments	(8)	(1)	(2)	—	(5)	(5)	—	—
AROs at December 31, 2025	$ 324	$ 194	$ 27	$ 36	$ 63	$ 46	$ 12	$ 5

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(a) For ComEd, PECO, BGE, DPL and ACE, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

9. Leases (All Registrants)

Lessee

The Registrants have operating and finance leases for which they are the lessees. The following tables outline the significant types of leases at each of the Registrants and other terms and conditions of the lease agreements as of December 31, 2025. Exelon, ComEd, PECO, and BGE did not have material finance leases in 2025, 2024, or 2023.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Real estate	●	●	●	●	●	●	●	●
Vehicles and equipment	●			●	●	●	●	●

(in years)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Remaining lease terms	1-80	1-27	1-9	1-80	1-7	1-7	1-7	1-7
Options to extend the term	3-30	N/A	N/A	3-5	3-30	5	3-30	N/A
Options to terminate within	2-7	N/A	N/A	2	N/A	N/A	N/A	N/A

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

The components of operating lease costs were as follows:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2025								
Operating lease costs	$ 47	$ —	$ —	$ 7	$ 31	$ 12	$ 9	$ 6
Variable lease costs	7	—	—	—	1	—	1	—
Total lease costs[(a)]	$ 54	$ —	$ —	$ 7	$ 32	$ 12	$ 10	$ 6
For the year ended December 31, 2024								
Operating lease costs	$ 57	$ —	$ —	$ 8	$ 41	$ 10	$ 10	$ 5
Variable lease costs	9	—	—	—	3	1	1	1
Total lease costs[(a)]	$ 66	$ —	$ —	$ 8	$ 44	$ 11	$ 11	$ 6
For the year ended December 31, 2023								
Operating lease costs	$ 58	$ 1	$ —	$ 5	$ 43	$ 11	$ 11	$ 6
Variable lease costs	9	1	—	—	3	1	1	1
Total lease costs[(a)]	$ 67	$ 2	$ —	$ 5	$ 46	$ 12	$ 12	$ 7

(a) Excludes sublease income recorded at Exelon, PHI, and DPL of $4 million for the years ended December 31, 2025, 2024, and 2023.

The components of financing lease costs were as follows:

	PHI	Pepco	DPL	ACE
For the year ended December 31, 2025				
Amortization of ROU asset	$ 21	$ 7	$ 8	$ 6
Interest on lease liabilities	6	2	2	2
Total finance lease cost	$ 27	$ 9	$ 10	$ 8
For the year ended December 31, 2024				
Amortization of ROU asset	$ 18	$ 7	$ 7	$ 4
Interest on lease liabilities	6	2	2	2
Total finance lease cost	$ 24	$ 9	$ 9	$ 6
For the year ended December 31, 2023				
Amortization of ROU asset	$ 16	$ 6	$ 6	$ 4
Interest on lease liabilities	6	2	2	1
Total finance lease cost	$ 22	$ 8	$ 8	$ 5

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

The following tables provide additional information regarding the presentation of operating and finance lease ROU assets and lease liabilities within the Registrants' Consolidated Balance Sheets:

	Operating Leases							
	Exelon	ComEd	PECO	BGE	PHI[(a)]	Pepco	DPL	ACE
At December 31, 2025								
Operating lease ROU assets								
Other deferred debits and other assets	$ 139	$ —	$ 1	$ 17	$ 54	$ 22	$ 23	$ 5
Operating lease liabilities								
Other current liabilities	$ 19	$ —	$ —	$ 3	$ 10	$ 4	$ 5	$ 1
Other deferred credits and other liabilities	146	—	1	13	55	22	28	5
Total operating lease liabilities	$ 165	$ —	$ 1	$ 16	$ 65	$ 26	$ 33	$ 6
At December 31, 2024								
Operating lease ROU assets								
Other deferred debits and other assets	$ 224	$ —	$ —	$ 24	$ 127	$ 26	$ 27	$ 7
Operating lease liabilities								
Other current liabilities	$ 38	$ —	$ —	$ 3	$ 30	$ 5	$ 6	$ 3
Other deferred credits and other liabilities	217	—	—	16	116	25	32	5
Total operating lease liabilities	$ 255	$ —	$ —	$ 19	$ 146	$ 30	$ 38	$ 8

(a) On April 15, 2025, PHI purchased an office building and land in the District of Columbia for $177 million which it had been leasing. PHI's operating lease liability and operating lease ROU asset amounts for the office building and land were $64 million and $47 million, respectively, at the time of the purchase. In conjunction with the purchase, the lease has been terminated and the difference of $17 million between the operating lease liability and operating lease ROU asset were recorded as an adjustment to the carrying value of the purchased assets.

	Finance Leases			
	PHI	Pepco	DPL	ACE
At December 31, 2025				
Finance lease ROU assets				
Plant, property and equipment, net	$ 68	$ 23	$ 25	$ 20
Finance lease liabilities				
Long-term debt due within one year	$ 19	$ 7	$ 7	$ 5
Long-term debt	53	18	20	15
Total finance lease liabilities	$ 72	$ 25	$ 27	$ 20
At December 31, 2024				
Finance lease ROU assets				
Plant, property and equipment, net	$ 72	$ 26	$ 26	$ 20
Finance lease liabilities				
Long-term debt due within one year	$ 17	$ 6	$ 7	$ 4
Long-term debt	58	21	21	16
Total finance lease liabilities	$ 75	$ 27	$ 28	$ 20

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

Future minimum lease payments for operating and finance leases as of December 31, 2025 were as follows:

	Operating Leases							
Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2026	$ 26	$ —	$ 1	$ 4	$ 13	$ 5	$ 6	$ 2
2027	24	—	—	2	12	4	7	2
2028	24	—	—	3	11	4	6	1
2029	24	—	—	3	11	4	6	1
2030	24	—	—	3	11	4	6	1
Remaining years	91	—	—	18	21	9	12	—
Total	213	—	1	33	79	30	43	7
Interest	48	—	—	17	14	4	10	1
Total operating lease liabilities	$ 165	$ —	$ 1	$ 16	$ 65	$ 26	$ 33	$ 6

	Finance Leases			
Year	PHI	Pepco	DPL	ACE
2026	$ 21	$ 8	$ 8	$ 6
2027	19	7	7	5
2028	15	5	6	4
2029	12	4	5	2
2030	7	2	2	2
Remaining years	6	1	2	3
Total	80	27	30	22
Interest	8	2	3	2
Total finance lease liabilities	$ 72	$ 25	$ 27	$ 20

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

	Operating Leases							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
At December 31, 2025	9.3	—	6.4	19.2	6.2	6.6	6.3	3.2
At December 31, 2024	8.2	1.7	5.3	17.4	5.3	7.1	6.9	3.1

	Finance Leases			
	PHI	Pepco	DPL	ACE
At December 31, 2025	4.1	4.0	3.9	4.4
At December 31, 2024	4.4	4.4	4.2	4.5

The weighted average discount rates for operating and finance leases were as follows:

	Operating Leases							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
At December 31, 2025	3.9 %	— %	4.4 %	5.0 %	4.2 %	4.2 %	4.2 %	4.2 %
At December 31, 2024	4.0 %	0.8 %	2.8 %	5.0 %	4.2 %	4.1 %	4.1 %	3.9 %

	Finance Leases			
	PHI	Pepco	DPL	ACE
At December 31, 2025	3.8 %	3.8 %	3.6 %	3.9 %
At December 31, 2024	3.4 %	3.5 %	3.1 %	3.5 %

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

Cash paid for amounts included in the measurement of operating and finance lease liabilities were as follows:

	Operating Cash Flows from Operating Leases							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2025	$ 35	$ —	$ —	$ 4	$ 22	$ 6	$ 7	$ 3
For the year ended December 31, 2024	48	—	—	4	35	7	7	3
For the year ended December 31, 2023	65	2	—	15	37	7	9	3

	Financing Cash Flows from Finance Leases			
	PHI	Pepco	DPL	ACE
For the year ended December 31, 2025	$ 20	$ 7	$ 8	$ 5
For the year ended December 31, 2024	17	6	7	4
For the year ended December 31, 2023	15	5	6	4

ROU assets obtained in exchange for operating and finance lease obligations were as follows:

	Operating Leases							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the year ended December 31, 2025	$ 3	$ —	$ —	$ —	$ 3	$ 1	$ 2	$ —
For the year ended December 31, 2024	8	—	—	1	5	1	2	2
For the year ended December 31, 2023	35	—	—	32	3	—	1	2

	Finance Leases			
	PHI	Pepco	DPL	ACE
For the year ended December 31, 2025	$ 15	$ 4	$ 6	$ 5
For the year ended December 31, 2024	15	7	4	4
For the year ended December 31, 2023	11	5	3	3

Lessor

The Registrants have operating leases for which they are the lessors. The following tables outline the significant types of leases at each of the Registrants and other terms and conditions of their lease agreements as of December 31, 2025. ACE did not have any operating leases for which they are the lessors for the years ended December 31, 2025, 2024, and 2023.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
Real estate	●	●	●	●	●	●	●

(in years)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
Remaining lease terms	1-77	1-11	1-77	17	1-7	1	6-7
Options to extend the term	1-79	5-79	1-50	N/A	N/A	N/A	N/A

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

The components of lease income were as follows:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
For the year ended December 31, 2025							
Operating lease income	$ 5	$ —	$ —	$ —	$ 4	$ —	$ 4
Variable lease income	1	—	—	—	1	—	1
For the year ended December 31, 2024							
Operating lease income	$ 4	$ —	$ —	$ —	$ 4	$ —	$ 3
Variable lease income	1	—	—	—	1	—	1
For the year ended December 31, 2023							
Operating lease income	$ 5	$ —	$ —	$ —	$ 4	$ —	$ 3
Variable lease income	1	—	—	—	1	—	1

Future minimum lease payments to be recovered under operating leases as of December 31, 2025 were as follows:

Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
2026	$ 7	$ 1	$ 1	$ —	$ 5	$ —	$ 4
2027	7	—	2	—	5	—	4
2028	6	—	1	—	5	—	5
2029	6	—	1	—	4	—	5
2030	5	—	1	—	4	—	4
Remaining years	17	—	7	1	9	—	9
Total	$ 48	$ 1	$ 13	$ 1	$ 32	$ —	$ 31

10. Intangible Assets

Goodwill (Exelon, ComEd, PHI, Pepco, DPL, and ACE)

The following table presents the gross amount, accumulated impairment loss, and carrying amount of Goodwill at Exelon, ComEd, and PHI at December 31, 2025 and 2024. There were no additions or impairments during the years ended December 31, 2025, 2024, and 2023.

	Gross Amount	Accumulated Impairment Loss	Carrying Amount
Exelon	$ 8,613	$ 1,983	$ 6,630
ComEd[(a)]	4,608	1,983	2,625
PHI[(b)]	4,005	—	4,005

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom merger (predecessor parent company of ComEd).
(b) Reflects goodwill recorded in 2016 from the PHI merger.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of ComEd's and PHI's reporting units below their carrying amounts. A reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is assessed for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment. PHI's operating segments are Pepco, DPL, and ACE. See Note 4 — Segment Information for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL, and ACE operating segments are also considered reporting units for goodwill impairment assessment purposes. Exelon's and ComEd's $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon's and

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

PHI's $4.0 billion of goodwill has been assigned to the Pepco, DPL, and ACE reporting units in the amounts of $2.1 billion, $1.4 billion, and $0.5 billion, respectively.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. As part of the qualitative assessments, Exelon, ComEd, and PHI evaluate, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed. If an entity bypasses the qualitative assessment, a quantitative, fair value-based assessment is performed, which compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the entity recognizes an impairment charge, which is limited to the amount of goodwill allocated to the reporting unit.

Application of the goodwill impairment assessment requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's, Pepco's, DPL's, and ACE's businesses, and the fair value of debt.

2025 and 2024 Goodwill Impairment Assessment. ComEd and PHI qualitatively determined that it was more likely than not that the fair values of their reporting units exceeded their carrying values and, therefore, did not perform quantitative assessments as of November 1, 2025 and 2024. The last quantitative assessments performed for PHI was as of November 1, 2018. On December 14, 2023, due to the issuance of the ICC's final order rejecting ComEd's proposed Grid Plan and establishing retail rates for 2024-2027 as further discussed in Note 2 — Regulatory Matters, Exelon's stock price decreased approximately 10% triggering an interim quantitative assessment for potential goodwill impairment at ComEd. ComEd performed a quantitative assessment as of December 31, 2023, comparing the estimated fair value of ComEd to its carrying value, and determined there was no indication of goodwill impairment.

While the annual and interim assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon's, ComEd's, and PHI's goodwill, which could be material.

Other Intangible Assets and Liabilities (Exelon and PHI)

Exelon's other intangible assets, included in Other current assets and Other deferred debits and other assets in the Consolidated Balance Sheets, consisted of the following at December 31, 2025 and 2024. Exelon's and PHI's other intangible liabilities, included in current and noncurrent Unamortized energy contract liabilities in their Consolidated Balance Sheets, consisted of the following at December 31, 2025 and 2024. The intangible assets and liabilities shown below are amortized on a straight-line basis, except for unamortized energy contracts which are amortized in relation to the expected realization of the underlying cash flows:

	December 31, 2025			December 31, 2024		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Exelon						
Unamortized Energy Contracts	$ (1,515)	$ 1,494	$ (21)	$ (1,515)	$ 1,489	$ (26)
Software License	81	(81)	—	81	(78)	3
Exelon Total	$ (1,434)	$ 1,413	$ (21)	$ (1,434)	$ 1,411	$ (23)
PHI						
Unamortized Energy Contracts	$ (1,515)	$ 1,494	$ (21)	$ (1,515)	$ 1,489	$ (26)

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

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2025, 2024, and 2023:

For the Years Ended December 31,	Exelon[(a)]	PHI[(a)]
2025	$ (2)	$ (5)
2024	(1)	(9)
2023	(1)	(10)

(a) For PHI unamortized energy contracts, the amortization of the fair value adjustment amounts and the corresponding offsetting regulatory asset amounts are amortized through Purchased power and fuel expense in their Consolidated Statements of Operations and Comprehensive Income resulting in no effect to net income.

11. Income Taxes (All Registrants)

Components of Income Tax Expense or Benefit

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

	For the Year Ended December 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:								
Federal								
Current	$ 119	$ 143	$ 97	$ 74	$ 91	$ 47	$ 28	$ 20
Deferred	169	(16)	(45)	28	60	18	16	24
Investment tax credit amortization	(1)	(1)	—	—	—	—	—	—
State								
Current	13	80	—	—	16	7	8	—
Deferred	223	55	(23)	57	72	34	17	23
Total	$ 523	$ 261	$ 29	$ 159	$ 239	$ 106	$ 69	$ 67

	For the Year Ended December 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:								
Federal								
Current	$ 42	$ 76	$ 51	$ 45	$ 97	$ 50	$ 29	$ 16
Deferred	(27)	(76)	(46)	(42)	21	3	3	20
Investment tax credit amortization	(2)	(1)	—	—	(1)	—	—	—
State								
Current	37	60	—	—	19	17	4	—
Deferred	157	57	(17)	46	53	20	13	19
Total	$ 207	$ 116	$ (12)	$ 49	$ 189	$ 90	$ 49	$ 55

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

	For the Year Ended December 31, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:								
Federal								
Current	$ 51	$ 130	$ 63	$ 67	$ 71	$ 54	$ 25	$ 9
Deferred	193	45	(36)	16	(8)	(28)	(6)	13
Investment tax credit amortization	(2)	(1)	—	—	(1)	—	—	—
State								
Current	4	(13)	—	—	15	12	6	—
Deferred	128	153	(7)	50	39	13	10	14
Total	$ 374	$ 314	$ 20	$ 133	$ 116	$ 51	$ 35	$ 36

Rate Reconciliation

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

	For the Year Ended December 31, 2025[(a)(b)]							
	Exelon		ComEd[(c)]		PECO[(d)]		BGE	
U.S. Federal Statutory Tax Rate	$ 691	21.0 %	$ 296	21.0 %	$ 177	21.0 %	$ 155	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit	187	5.7	107	7.6	(18)	(2.1)	45	6.1
Tax credits	(13)	(0.4)	(6)	(0.4)	—	—	(3)	(0.4)
Nontaxable or nondeductible items	13	0.4	1	0.1	1	0.1	1	0.2
Other Adjustments								
Plant basis differences	(145)	(4.4)	(13)	(1.0)	(117)	(13.9)	(11)	(1.5)
Excess deferred tax	(208)	(6.3)	(123)	(8.7)	(14)	(1.7)	(28)	(3.8)
Amortization of ITC, net deferred taxes	(2)	(0.1)	(1)	(0.1)	—	—	—	—
Effective Tax Rate	$ 523	15.9 %	$ 261	18.5 %	$ 29	3.4 %	$ 159	21.6 %

	For the Year Ended December 31, 2025[(a)(b)]							
	PHI		PEPCO		DPL		ACE	
U.S. Federal Statutory Tax Rate	$ 218	21.0 %	$ 106	21.0 %	$ 62	21.0 %	$ 53	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit	70	6.7	32	6.3	20	6.8	18	7.1
Tax credits	(4)	(0.4)	(2)	(0.4)	(1)	(0.3)	(1)	(0.4)
Nontaxable or nondeductible items	3	0.3	2	0.3	(1)	(0.3)	1	0.2
Other Adjustments								
Plant basis differences	(5)	(0.5)	(3)	(0.6)	(1)	(0.3)	(1)	(0.4)
Excess deferred tax	(42)	(4.0)	(29)	(5.7)	(10)	(3.4)	(3)	(1.2)
Amortization of ITC, net deferred taxes	(1)	(0.1)	—	—	—	—	—	—
Effective Tax Rate	$ 239	23.0 %	$ 106	20.9 %	$ 69	23.5 %	$ 67	26.3 %

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

	For the Year Ended December 31, 2024[a][b]							
	Exelon		ComEd[c]		PECO[d]		BGE[e]	
U.S. Federal Statutory Tax Rate	$ 560	21.0 %	$ 248	21.0 %	$ 113	21.0 %	$ 121	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit	153	5.7	92	7.8	(13)	(2.4)	36	6.3
Tax credits	(19)	(0.6)	(13)	(1.1)	—	—	(2)	(0.3)
Nontaxable or nondeductible items	6	0.2	2	0.2	—	—	1	0.1
Other Adjustments								
Plant basis differences	(120)	(4.5)	(8)	(0.7)	(96)	(17.8)	(8)	(1.4)
Excess deferred tax	(371)	(13.9)	(204)	(17.3)	(16)	(3.0)	(99)	(17.2)
Amortization of ITC, net deferred taxes	(2)	(0.1)	(1)	(0.1)	—	—	—	—
Effective Tax Rate	$ 207	7.8 %	$ 116	9.8 %	$ (12)	(2.2)%	$ 49	8.5 %

	For the Year Ended December 31, 2024[a][b]							
	PHI		PEPCO		DPL		ACE	
U.S. Federal Statutory Tax Rate	$ 195	21.0 %	$ 101	21.0 %	$ 54	21.0 %	$ 44	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit	57	6.1	29	6.0	13	5.0	15	7.1
Tax credits	(4)	(0.4)	(2)	(0.4)	(1)	(0.4)	(1)	(0.5)
Nontaxable or nondeductible items	1	0.1	—	—	1	0.4	—	—
Other Adjustments								
Plant basis differences	(7)	(0.8)	(5)	(1.0)	(3)	(1.2)	1	0.5
Excess deferred tax	(52)	(5.6)	(33)	(6.8)	(15)	(5.8)	(4)	(1.9)
Amortization of ITC, net deferred taxes	(1)	(0.1)	—	—	—	—	—	—
Effective Tax Rate	$ 189	20.3 %	$ 90	18.8 %	$ 49	19.0 %	$ 55	26.2 %

	For the Year Ended December 31, 2023[a][b]							
	Exelon		ComEd		PECO[d]		BGE	
U.S. Federal Statutory Tax Rate	$ 567	21.0 %	$ 295	21.0 %	$ 122	21.0 %	$ 130	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit	104	3.8	111	7.9	(6)	(1.0)	40	6.5
Tax credits	(16)	(0.6)	(8)	(0.6)	—	—	(3)	(0.5)
Nontaxable or nondeductible items	7	0.3	1	0.2	2	0.2	—	—
Other Adjustments								
Plant basis differences	(106)	(3.9)	(7)	(0.5)	(84)	(14.4)	(6)	(1.0)
Excess deferred tax	(180)	(6.7)	(77)	(5.5)	(14)	(2.4)	(28)	(4.5)
Amortization of ITC, net deferred taxes	(2)	(0.1)	(1)	(0.1)	—	—	—	—
Effective Tax Rate	$ 374	13.8 %	$ 314	22.4 %	$ 20	3.4 %	$ 133	21.5 %

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

	For the Year Ended December 31, 2023[a][b]							
	PHI		PEPCO		DPL		ACE	
U.S. Federal Statutory Tax Rate	$ 148	21.0 %	$ 75	21.0 %	$ 45	21.0 %	$ 33	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit	43	6.1	20	5.5	13	6.1	11	7.1
Tax credits	(3)	(0.6)	(3)	(0.7)	(1)	(0.4)	(1)	(0.6)
Nontaxable or nondeductible items	—	0.1	1	0.3	—	—	1	0.7
Other Adjustments								
Plant basis differences	(10)	(1.5)	(8)	(2.2)	(2)	(0.8)	(1)	(0.6)
Excess deferred tax	(61)	(8.6)	(34)	(9.6)	(20)	(9.4)	(7)	(4.5)
Amortization of ITC, net deferred taxes	(1)	(0.1)	—	—	—	—	—	—
Effective Tax Rate	$ 116	16.4 %	$ 51	14.3 %	$ 35	16.5 %	$ 36	23.1 %

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(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) Exelon and Registrants had no adjustments related to the following disclosure categories: Foreign Tax Effects, Effects of Changes in Tax law or Rates Enacted in the Current Period, Effects of Cross-Border Tax Laws, Changes in Valuation Allowances, and Changes in Unrecognized Tax Benefits.
(c) For ComEd, the lower effective tax rate is primarily due to CEJA which resulted in the acceleration of certain income tax benefits being provided to customers.
(d) For PECO, the lower effective tax rate is primarily related to state income taxes, net of federal income tax benefit and plant basis differences attributable to tax repair deductions.
(e) For BGE, the lower effective tax rate is primarily due to the Maryland Multi-year plan which resulted in the acceleration of certain tax benefits being provided to customers.

State and local Income Tax (Major Jurisdictions)

The state and local jurisdictions that comprise the majority of the effect of the state and local income tax, net of federal income taxes category by Registrant are presented below:

	2025	2024	2023
Exelon	IL, MD	IL, MD	MD, IL
ComEd	IL	IL	IL
PECO	PA	PA	PA
BGE	MD	MD	MD
PHI	MD, NJ	MD, NJ	MD, NJ
Pepco	MD	MD	MD
DPL	DE	DE	DE
ACE	NJ	NJ	NJ

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

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), at December 31, 2025 and 2024 are presented below:

	At December 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$(13,989)	$ (5,231)	$ (2,676)	$ (2,411)	$ (3,596)	$ (1,628)	$ (1,033)	$ (936)
Accrual based contracts	18	—	—	—	5	—	—	—
Derivatives and other financial instruments	26	36	—	—	1	—	—	—
Deferred pension and postretirement obligation	506	(382)	(41)	(20)	(60)	(57)	(28)	—
Deferred debt refinancing costs	101	(4)	—	(2)	91	(2)	(1)	(1)
Regulatory assets and liabilities	(1,756)	(490)	(324)	(39)	(122)	(36)	29	(25)
Tax loss carryforward, net of valuation allowances	275	—	72	63	67	—	14	53
Tax credit carryforward	—	—	—	—	—	—	—	—
Corporate Alternative Minimum Tax	553	—	289	142	71	44	17	20
Investment in partnerships	(28)	—	—	—	—	—	—	—
Other, net	601	250	86	26	166	76	9	23
Deferred income tax liabilities (net)	(13,693)	(5,821)	(2,594)	(2,241)	(3,377)	(1,603)	(993)	(866)
Unamortized investment tax credits	(15)	(7)	—	(1)	(7)	(1)	(3)	(3)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(13,708)	$ (5,828)	$ (2,594)	$ (2,242)	$ (3,384)	$ (1,604)	$ (996)	$ (869)

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

	At December 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$(13,150)	$ (5,069)	$ (2,446)	$ (2,232)	$ (3,371)	$(1,512)	$(975)	$(881)
Accrual based contracts	19	—	—	—	6	—	—	—
Derivatives and other financial instruments	21	36	—	—	1	—	—	—
Deferred pension and postretirement obligation	512	(339)	(39)	(24)	(68)	(64)	(32)	—
Deferred debt refinancing costs	108	(4)	—	(2)	98	(3)	(1)	(1)
Regulatory assets and liabilities	(1,665)	(515)	(254)	(37)	(96)	(16)	33	(18)
Tax loss carryforward, net of valuation allowances	283	—	63	78	68	—	16	51
Tax credit carryforward	142	—	—	—	—	—	—	—
Corporate Alternative Minimum Tax	369	47	166	95	2	2	4	8
Investment in partnerships	(27)	—	—	—	—	—	—	—
Other, net	612	249	77	24	180	85	10	27
Deferred income tax liabilities (net)	(12,776)	(5,595)	(2,433)	(2,098)	(3,180)	(1,508)	(945)	(814)
Unamortized investment tax credits	(10)	(6)	—	(1)	(3)	(1)	(1)	(2)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(12,786)	$ (5,601)	$ (2,433)	$ (2,099)	$ (3,183)	$(1,509)	$(946)	$(816)

The following table provides federal and state tax attribute carryforwards at December 31, 2025 for Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE. The state net operating loss carryforwards and any corresponding valuation allowance are presented on a post-apportioned basis.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Federal								
Federal general business credits carryforwards	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Minimum Tax credit carryforward[(a)]	$ 553	$ —	$ 289	$ 142	$ 71	$ 44	$ 17	$ 20
State								
State net operating loss carryforwards	$ 6,684	$ —	$ 1,944	$ 972	$ 1,387	$ —	$ 635	$ 752
Deferred taxes on state tax attributes (net of federal taxes)	$ 381	$ —	$ 76	$ 63	$ 96	$ —	$ 43	$ 53
Valuation allowance on state tax attributes (net of federal taxes)[(b)]	$ 106	$ —	$ 4	$ —	$ 29	$ —	$ 29	$ —
Year in which net operating loss or credit carryforwards will begin to expire[(c)]	2031	N/A	2031	2033	2031	N/A	2033	2031

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(a) For Exelon, PECO, BGE, PHI, Pepco, DPL, and ACE, the Corporate Alternative Minimum Tax credit carryforward has an indefinite carryforward period.

(b) For Exelon, a full valuation allowance has been recorded against certain separate company state net operating loss carryforwards that are expected to expire before realization. For PECO, a valuation allowance has been recorded against Pennsylvania net operating losses that are expected to expire before realization. For DPL, a full valuation allowance has been recorded against Delaware net operating losses carryforwards due to a change in Delaware tax law that limits the ability of corporate taxpayers to monetize net operating losses.

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

(c) A portion of Exelon's, BGE's, and DPL's Maryland state net operating loss carryforward have an indefinite carryforward period.

Tabular Reconciliation of Unrecognized Tax Benefits

The following table presents changes in unrecognized tax benefits, for Exelon, PHI, DPL, and ACE. Amounts for ComEd, PECO, BGE, and Pepco are not material.

	Exelon[a]	PHI	DPL	ACE
Balance at January 1, 2023	$ 148	$ 59	$ 4	$ 17
Change to positions that only affect timing	(57)	(9)	(2)	(2)
Increases based on tax positions related to 2023	3	1	—	—
Increases based on tax positions prior to 2023	1	—	—	—
Decreases based on tax positions prior to 2023	(1)	—	—	—
Balance at December 31, 2023	$ 94	$ 51	$ 2	$ 15
Change to positions that only affect timing	10	10	—	—
Increases based on tax positions related to 2024	4	1	10	—
Increases based on tax positions prior to 2024	2	—	—	—
Decreases based on tax positions prior to 2024	(14)	(14)	—	(14)
Balance at December 31, 2024	$ 96	$ 48	$ 12	$ 1
Change to positions that only affect timing	—	(1)	—	—
Increases based on tax positions related to 2025	3	1	—	—
Increases based on tax positions prior to 2025	1	—	—	—
Decreases based on tax positions prior to 2025	—	—	—	—
Balance at December 31, 2025	$ 100	$ 48	$ 12	$ 1

(a) At December 31, 2025 and 2024, Exelon recorded a receivable of $31 million and $31 million, respectively, in noncurrent Other assets in the Consolidated Balance Sheet for Constellation’s share of unrecognized tax benefits for periods prior to the separation of Exelon and Constellation in February 2022.

Unrecognized Tax Benefits

The following table presents Exelon's unrecognized tax benefits that, if recognized, would decrease the effective tax rate. The Utility Registrants' amounts are not material.

	Exelon
December 31, 2025	$ 83
December 31, 2024	69
December 31, 2023	71

At December 31, 2025 Exelon, PHI, and DPL have approximately $65 million, $6 million, and $1 million, respectively, of unrecognized federal tax benefits that could significantly change within the 12 months after the reporting date based on the outcome of pending refund claims that impacts the effective tax rate.

Total Amounts of Interest and Penalties Recognized

The following table represents the net interest and penalties receivable (payable) related to tax positions reflected in Exelon's Consolidated Balance Sheets. The Utility Registrants' amounts are not material.

Net interest and penalties receivable at	Exelon
December 31, 2025 [a]	$ 61
December 31, 2024 [b]	76

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

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(a) At December 31, 2025, Exelon classified $7 million and $54 million of the interest receivable as current and noncurrent, respectively, based on the expected timing for settlement in cash. At December 31, 2025, Exelon recorded a receivable of $12 million in noncurrent Other assets in the Consolidated Balance Sheet for Constellation's share of net interest for periods prior to the separation of Exelon and Constellation in February 2022.
(b) At December 31, 2024, Exelon classified $27 million and $49 million of the interest receivable as current and noncurrent, respectively, based on the expected timing for settlement in cash. At December 31, 2024, Exelon recorded a receivable of $9 million in noncurrent Other assets in the Consolidated Balance Sheet for Constellation's share of net interest for periods prior to the separation of Exelon and Constellation in February 2022.

The Registrants did not record material interest or penalties related to tax positions reflected in their Consolidated Balance Sheets. Interest and penalties are recorded in Interest expense, net and Other, net, respectively, in Other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Description of Tax Years Open to Assessment by Major Jurisdiction

Major Jurisdiction	Open Years	Registrants Impacted
Federal consolidated income tax returns[a]	2010-2024	All Registrants
Delaware separate corporate income tax returns	2010-2024	DPL
District of Columbia combined corporate income tax returns	2022-2024	Exelon, PHI, Pepco
Illinois unitary corporate income tax returns	2012-2024	Exelon, ComEd
Maryland separate company corporate net income tax returns	2010-2024	BGE, Pepco, DPL
New Jersey combined corporate income tax returns	2021-2024	Exelon
New Jersey separate corporate income tax returns	2021-2024	ACE
Pennsylvania separate corporate income tax returns	2021-2024	Exelon
Pennsylvania separate corporate income tax returns	2021-2024	PECO

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(a) Certain registrants are only open to assessment for tax years since joining the Exelon federal consolidated group; BGE beginning in 2012 and PHI, Pepco, DPL, and ACE beginning in 2016.

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

Tax Payments (Refunds) by Major Jurisdiction

	For the Year Ended December 31, 2025							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Federal[a]	$ —	$ 128	$ (186)	$ (95)	$ 88	$ 69	$ 13	$ 11
Delaware	8	—	—	—	8	—	7	—
District of Columbia	—	—	—	—	4	6	—	—
Illinois	(1)	96	—	—	—	—	—	—
Maryland	14	—	—	—	14	13	—	—
Pennsylvania	(10)	—	—	—	—	—	—	—
Other States	1	—	—	—	—	—	—	—
Total Payments (Refunds)	$ 12	$ 224	$ (186)	$ (95)	$ 114	$ 88	$ 20	$ 11

	For the Year Ended December 31, 2024							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Federal	$ 54	$ 188	$ 128	$ 100	$ 119	$ 62	$ 43	$ 20
Delaware	13	—	—	—	13	—	13	—
District of Columbia	—	—	—	—	5	21	—	—
Illinois	—	62	—	—	—	—	—	—
Maryland	13	—	—	—	13	13	—	—
Pennsylvania	—	—	—	—	—	—	—	—
Other States	1	—	—	—	—	—	1	—
Total Payments	$ 81	$ 250	$ 128	$ 100	$ 150	$ 96	$ 57	$ 20

	For the Year Ended December 31, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Federal	$ 18	$ 40	$ (24)	$ 29	$ 25	$ 14	$ 6	$ 9
Delaware	2	—	—	—	2	—	—	—
District of Columbia	—	—	—	—	(6)	(8)	—	—
Illinois	—	(28)	—	—	—	—	—	—
Maryland	1	—	—	—	—	—	—	—
Pennsylvania	(1)	—	—	—	—	—	—	—
Other States	(10)	(1)	—	—	—	—	—	—
Total Payments (Refunds)	$ 10	$ 11	$ (24)	$ 29	$ 21	$ 6	$ 6	$ 9

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(a) In 2025, Exelon received a one-time federal refund claim that reduced current year federal tax payments to a net zero.

Other Tax Matters

Tax Matters Agreement (Exelon)

In February 2022, in connection with the separation between Exelon and Constellation, the parties entered into a TMA. The TMA governs the respective rights, responsibilities, and obligations between Exelon and Constellation after the separation with respect to tax liabilities, refunds and attributes for open tax years that Constellation was part of Exelon's consolidated group for U.S. federal, state, and local tax purposes.

Indemnification for Taxes. As a former subsidiary of Exelon, Constellation has joint and several liability with Exelon to the IRS and certain state jurisdictions relating to the taxable periods prior to the separation. The TMA specifies that Constellation is liable for their share of taxes required to be paid by Exelon with respect to taxable periods prior to the separation to the extent Constellation would have been responsible for such taxes under the existing Exelon tax sharing agreement when Constellation was included in Exelon's consolidated group. At December 31, 2025, there is no balance due to or from Constellation.

Tax Refunds. The TMA specifies that Constellation is entitled to their share of any future tax refunds claimed by Exelon with respect to taxable periods prior to the separation to the extent that Constellation would have received such tax refunds under the existing Exelon tax sharing agreement when Constellation was included in Exelon's consolidated group. At December 31, 2025, there is no balance due to or from Constellation.

Tax Attributes. At the date of separation certain tax attributes, primarily tax credit carryforwards, that were generated by Constellation prior to the separation, were required by law to be allocated to Exelon. The TMA also provides that Exelon will reimburse Constellation when those allocated tax attribute carryforwards are utilized. In 2025, Exelon remitted $143 million of payments to Constellation for the utilization of pre-separation tax credit carryforwards. At December 31, 2025, Exelon recorded a payable of $175 million and $21 million in Other current liabilities and Other deferred credits and other liabilities, respectively, in the Consolidated Balance Sheet for tax attribute carryforwards that are expected to be utilized and reimbursed to Constellation.

Corporate Alternative Minimum Tax (All Registrants)

On August 16, 2022, the IRA was signed into law and implemented a new corporate alternative minimum tax (CAMT) that imposes a 15.0% tax on modified GAAP net income. Corporations will now pay the greater of 15.0% of financial statement pre-tax income (with certain adjustments) or their regular federal tax liability, which is federal taxable income x 21.0% federal corporate tax rate. Corporations are entitled to a tax credit (minimum tax credit) to the extent the CAMT liability exceeds the regular tax liability. This amount can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT.

Beginning in 2023, based on the existing statue, Exelon and each of the Utility Registrants will be subject to and will report the CAMT on a separate Registrant basis in the Consolidated Statements of Operations and Comprehensive Income and the Consolidated Balance Sheets. The deferred tax asset related to the minimum tax credit carryforward will be realized to the extent Exelon’s consolidated deferred tax liabilities exceed the minimum tax credit carryforward. Exelon’s deferred tax liabilities are expected to exceed the minimum tax credit carryforward for the foreseeable future and thus no valuation allowance is required.

On September 12, 2024, the U.S. Treasury issued proposed regulations providing further guidance addressing the implementation of CAMT. The proposed regulations are consistent with Exelon’s prior interpretation and therefore there are no financial statement impacts. Exelon will continue to monitor and assess the potential financial statement impacts of final regulations or other guidance when issued.

On September 30, 2025, the U.S. Treasury issued interim guidance addressing the implementation of CAMT in the form of a notice. The guidance allows entities with regulated operations a repairs adjustment for CAMT purposes, however the provision was drafted in a manner that does not achieve that intended result. Thus, the guidance does not benefit Exelon and has no financial statement impact. Exelon will continue to monitor and assess the potential financial statement impacts of future regulations or other guidance when issued.

Allocation of Income Taxes to Regulated Utilities (All Registrants)

In Q2 2024, the IRS issued a series of PLRs, to another taxpayer, providing guidance with respect to the application of the tax normalization rules to the allocation of consolidated tax benefits among the members of a consolidated group associated with NOLC for ratemaking purposes. The rulings provide that for ratemaking purposes the tax benefit of NOLC should be reflected on a separate company basis not taking into consideration the utilization of losses by other affiliates. A PLR issued to another taxpayer may not be relied on as precedent.

For the Registrants, except for PECO, the methodology prescribed by the IRS in these PLRs could result in a material reduction of the regulatory liability established for EDITs arising from the TCJA corporate tax rate change that are being amortized and flowed through to customers as well as a reduction in the accumulated deferred income taxes included in rate base for ratemaking purposes. The Utility Registrants, except for PECO, filed PLR requests with the IRS confirming the treatment of the NOLC for ratemaking purposes. The Utility Registrants will record the impact, if any, upon receiving the PLR from the IRS.

One Big Beautiful Bill Act (All Registrants)

On July 4, 2025, the OBBBA was signed into law. The bill permanently extends expiring tax benefits of the TCJA and provides additional tax relief for individuals and businesses while accelerating the phase-out and curtailment of certain renewable energy tax credits enacted by the IRA. The tax law changes enacted as part of OBBBA will not have a direct material impact on the Registrants' financial statements.

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

Long-Term Marginal State Income Tax Rate (All Registrants)

Quarterly, Exelon reviews and updates its marginal state income tax rates for material changes in state tax laws and state apportionment. The Registrants remeasure their existing deferred income tax balances to reflect the changes in marginal rates, which results in either an increase or a decrease to their net deferred income tax liability balances. Utility Registrants record corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. In the third quarter of 2023, Exelon updated its marginal state income tax rates for changes in state apportionment. The changes in marginal rates in the third quarter resulted in a decrease of $54 million to the deferred tax liability at Exelon, and a corresponding adjustment to income tax expense, net of federal taxes. There were no impacts to ComEd, BGE, PHI, Pepco, DPL, and ACE for the year ended December 31, 2023. There were no impacts to Exelon, ComEd, BGE, PHI, Pepco, DPL, and ACE for the years ended December 31, 2025 and 2024.

December 31, 2025	Exelon
Decrease to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ —
December 31, 2024	
Decrease to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	—
December 31, 2023	
Decrease to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	(54)

Allocation of Tax Benefits (All Registrants)

The Utility Registrants are party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net federal and state benefits attributable to Exelon are reallocated to the other Registrants. That allocation is treated as a contribution from Exelon to the party receiving the benefit.

The following table presents the allocation of tax benefits from Exelon under the Tax Sharing Agreement, for the year ended December 31, 2025, 2024, and 2023.

	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2025	$ 20	$ 14	$ 12	$ 23	$ 12	$ 7	$ 4
December 31, 2024	30	15	14	16	9	5	2
December 31, 2023[(a)]	13	19	—	10	4	—	2

(a) BGE and DPL did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

12. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension and OPEB plans. Substantially all non-union employees hired on or after January 1, 2001, participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired BSC non-represented, non-craft employees are not eligible to participate in defined benefit pension plans; January 1, 2021, most newly hired utility management employees are not eligible; and certain newly-hired union employees, pursuant to their collective bargaining agreements, are not eligible. In lieu of pension participation, affected employees are eligible to receive an automatic company contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly hired non-represented, non-craft employees are not eligible for OPEB benefits. Effective January 1, 2021, most non-represented, non-craft employees who are under the age of 40 are not eligible for retiree health care benefits. Certain union represented employees are not eligible for retiree healthcare benefits pursuant to their collective bargaining agreements. Effective January 1, 2022, management employees retiring on or after that date are no longer eligible for retiree life insurance benefits.

The tables below show the pension and OPEB plans in which current and former employees of each operating company participated as of December 31, 2025:

	Operating Company[(a)]						
Name of Plan:	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Qualified Pension Plans:							
Exelon Corporation Retirement Program (ECRP)	X	X	X	X	X	X	X
Exelon Corporation Pension Plan for Bargaining Unit Employees (PPBU)	X						
Exelon Pension Plan (EPP)	X	X	X	X	X	X	X
Pepco Holdings LLC Retirement Plan (PHI Qualified)	X	X	X	X	X	X	X
Non-Qualified Pension Plans:							
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan	X	X		X			
Exelon Corporation Supplemental Management Retirement Plan	X	X	X	X			
Constellation Energy Group, Inc. Senior Executive Supplemental Plan			X	X			
Constellation Energy Group, Inc. Supplemental Pension Plan			X	X			
Constellation Energy Group, Inc. Benefits Restoration Plan		X	X	X			
Baltimore Gas & Electric Company Executive Benefit Plan			X				
Baltimore Gas & Electric Company Manager Benefit Plan		X	X				
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan		X		X	X	X	X
Conectiv Supplemental Executive Retirement Plan				X		X	X
Pepco Holdings LLC Combined Executive Retirement Plan				X	X		

	Operating Company[(a)]						
Name of Plan:	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
OPEB Plans:							
PECO Energy Company Retiree Medical Plan (East)	X	X	X	X	X	X	X
Exelon Corporation Health Care Program (West)	X	X	X	X	X	X	X
Pepco Holdings LLC Welfare Plan for Retirees (PHI PRW)		X	X	X	X	X	X
Exelon Corporation Employees' Life Insurance Plan	X	X	X				
Exelon Corporation Health Reimbursement Arrangement Plan	X	X	X				
BGE Retiree Medical Plan	X	X	X	X	X	X	X
BGE Retiree Dental Plan			X				
Exelon Retiree Medical Plan of Constellation Energy Nuclear Group, LLC	X		X	X			
Exelon Retiree Dental Plan of Constellation Energy Nuclear Group, LLC	X		X	X			

(a) Employees generally remain in their legacy benefit plans when transferring between operating companies.

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

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Exelon has elected that the trusts underlying these plans be treated as qualified trusts under the IRC. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets, and Funded Status

During the first quarter of 2025, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2025. This valuation resulted in an increase to the pension obligation of $1 million and an increase to the OPEB obligation and asset of $6 million and $2 million, respectively. Additionally, AOCI decreased by $5 million (after-tax) and regulatory assets increased by $8 million and liabilities decreased by $3 million.

The following tables provide a rollforward of the changes in the benefit obligations and plan assets of Exelon for the most recent two years for all plans combined:

	Pension Benefits		OPEB	
	2025	2024	2025	2024
Change in benefit obligation:				
Net benefit obligation as of the beginning of the year	$ 10,545	$ 10,988	$ 1,837	$ 1,908
Service cost	154	166	25	27
Interest cost	586	565	101	96
Plan participants' contributions	—	—	26	27
Actuarial loss (gain)[(a)]	294	(331)	112	(32)
Settlements	(5)	(22)	—	—
Gross benefits paid	(837)	(821)	(189)	(189)
Net benefit obligation as of the end of the year	$ 10,737	$ 10,545	$ 1,912	$ 1,837

	Pension Benefits		OPEB	
	2025	2024	2025	2024
Change in plan assets:				
Fair value of net plan assets as of the beginning of the year	$ 8,785	$ 9,402	$ 1,355	$ 1,355
Actual return on plan assets	739	100	151	108
Employer contributions	293	126	49	54
Plan participants' contributions	—	—	26	27
Gross benefits paid	(837)	(821)	(189)	(189)
Settlements	(5)	(22)	—	—
Fair value of net plan assets as of the end of the year	$ 8,975	$ 8,785	$ 1,392	$ 1,355

(a) The pension and OPEB loss in 2025 primarily reflect a decrease in the discount rate. The pension and OPEB gains in 2024 primarily reflect an increase in the discount rate.

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

Exelon presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		OPEB	
	2025	2024	2025	2024
Other noncurrent assets	$ —	$ —	$ 44	$ 10
Other current liabilities	(13)	(15)	(18)	(20)
Pension obligations	(1,749)	(1,745)	—	—
Non-pension postretirement benefit obligations	—	—	(546)	(472)
Unfunded status, net (net benefit obligation less plan assets)	$ (1,762)	$ (1,760)	$ (520)	$ (482)

The following table provides the ABO and fair value of plan assets for all pension plans with an ABO in excess of plan assets. Information for pension and OPEB plans with projected benefit obligations (PBO) and accumulated postretirement benefit obligations (APBO), respectively, in excess of plan assets have been disclosed in the Obligations and Plan Assets table above as all pension and a majority of the OPEB plans are underfunded.

	Exelon	
	2025	2024
ABO	$ 10,294	$ 10,076
Fair value of net plan assets	8,975	8,785

Components of Net Periodic Benefit Costs

The majority of the 2025 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 5.68%. The majority of the 2025 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.50% for funded plans and a discount rate of 5.64%.

A portion of the net periodic benefit cost for all plans is capitalized in the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the years ended December 31, 2025, 2024, and 2023.

	Pension Benefits			OPEB		
	2025	2024	2023	2025	2024	2023
Components of net periodic benefit cost:						
Service cost	$ 154	$ 166	$ 155	$ 25	$ 27	$ 26
Interest cost	586	565	578	101	96	101
Expected return on assets	(713)	(736)	(755)	(84)	(84)	(83)
Amortization of:						
Prior service cost (credit)	2	2	2	(8)	(8)	(10)
Actuarial loss (gain)	212	214	166	(3)	—	(2)
Settlement and other charges	3	10	20	—	—	—
Net periodic benefit cost	$ 244	$ 221	$ 166	$ 31	$ 31	$ 32

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

Cost Allocation to Exelon Subsidiaries

PHI and each of the Utility Registrants account for their participation in Exelon’s pension and OPEB plans by applying multi-employer accounting. Exelon allocates costs related to its pension and OPEB plans to its subsidiaries based on both active and retired employee participation in each plan.

The amounts below represent the Registrants' allocated pension and OPEB costs (benefits). For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant, and equipment, net while the non-service cost components are included in Other, net and Regulatory assets. For PHI and each of the Utility Registrants, which apply multi-employer accounting, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant, and equipment, net in their consolidated financial statements.

For the Years Ended December 31,	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2025	$ 273	$ 85	$ 7	$ 62	$ 96	$ 35	$ 17	$ 13
2024	252	72	(1)	59	93	32	15	12
2023	198	26	(14)	56	99	34	18	13

Components of AOCI and Regulatory Assets

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its Consolidated Balance Sheets, with offsetting entries to AOCI and Regulatory assets (liabilities). A portion of current year actuarial (gains) losses and prior service costs (credits) are capitalized in Exelon’s Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and Regulatory assets (liabilities) for Exelon for the years ended December 31, 2025, 2024, and 2023 for all plans combined.

	Pension Benefits			OPEB		
	2025	2024	2023	2025	2024	2023
Changes in plan assets and benefit obligations recognized in AOCI and Regulatory assets (liabilities):						
Current year actuarial loss (gain)	$ 268	$ 305	$ 523	$ 45	$ (56)	$ 30
Amortization of actuarial (loss) gain	(212)	(214)	(166)	3	—	2
Current year prior service cost	—	—	4	—	—	—
Amortization of prior service (cost) credit	(2)	(2)	(2)	8	8	10
Settlements	(3)	(10)	(20)	—	—	—
Total recognized in AOCI and Regulatory assets (liabilities)	$ 51	$ 79	$ 339	$ 56	$ (48)	$ 42
Total recognized in AOCI	$ 32	$ 56	$ 99	$ 8	$ (1)	$ 4
Total recognized in Regulatory assets (liabilities)	$ 19	$ 23	$ 240	$ 48	$ (47)	$ 38

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

The following table provides the components of gross AOCI and Regulatory assets (liabilities) for Exelon that have not been recognized as components of periodic benefit cost as of December 31, 2025 and 2024 for all plans combined:

	Pension Benefits		OPEB	
	2025	2024	2025	2024
Prior service cost (credit)	$ 16	$ 19	$ (28)	$ (37)
Actuarial loss (gain)	4,082	4,029	(109)	(157)
Total	$ 4,098	$ 4,048	$ (137)	$ (194)
Total included in AOCI	$ 1,060	$ 1,028	$ (10)	$ (18)
Total included in Regulatory assets (liabilities)	$ 3,038	$ 3,020	$ (127)	$ (176)

Average Remaining Service Period

For pension benefits, Exelon amortizes its unrecognized prior service costs (credits) and certain actuarial (gains) losses, as applicable, based on participants' average remaining service periods.

For OPEB, Exelon amortizes its unrecognized prior service costs (credits) over participants' average remaining service period to benefit eligibility age and amortizes certain actuarial (gains) losses over participants' average remaining service period to expected retirement. The resulting average remaining service periods for pension and OPEB were as follows:

	2025	2024	2023
Pension plans	12.4	12.5	12.6
OPEB plans:			
Benefit Eligibility Age	7.7	7.8	8.1
Expected Retirement	8.7	9.0	9.3

Assumptions

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

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

Mortality. The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. For the years ended December 31, 2025 and 2024, Exelon's mortality assumption utilizes the SOA 2019 base table (Pri-2012) and MP-2021 improvement scale adjusted to use Proxy SSA ultimate improvement rates.

For Exelon, the following assumptions were used to determine the benefit obligations for the plans as of December 31, 2025 and 2024. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

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

	Pension Benefits		OPEB	
	2025	2024	2025	2024
Discount rate[(a)]	5.42 %	5.68 %	5.34 %	5.64 %
Investment crediting rate[(b)]	5.92 %	5.69 %	N/A	N/A
Rate of compensation increase	3.75 %	3.75 %	3.75 %	3.75 %
Mortality table	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)
Health care cost trend on covered charges	N/A	N/A	Initial trend rate of 6.50% and ultimate trend rate of 5.00%	Initial and ultimate trend rate of 5.00%

(a) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and OPEB obligations. Certain benefit plans used individual rates, which range from 5.21% - 5.54% and 5.27% - 5.34% for pension and OPEB plans, respectively, as of December 31, 2025 and 5.56% - 5.76% and 5.60% - 5.64% for pension and OPEB plans, respectively, as of December 31, 2024.
(b) The investment crediting rate above represents a weighted average rate.

The following assumptions were used to determine the net periodic benefit cost for Exelon for the years ended December 31, 2025, 2024 and 2023:

	Pension Benefits			OPEB		
	2025	2024	2023	2025	2024	2023
Discount rate[(a)]	5.68 %	5.19 %	5.53 %	5.64 %	5.17 %	5.51 %
Investment crediting rate[(b)]	5.69 %	5.03 %	5.07 %	N/A	N/A	N/A
Expected return on plan assets[(c)]	7.00 %	7.00 %	7.00 %	6.50 %	6.50 %	6.50 %
Rate of compensation increase	3.75 %	3.75 %	3.75 %	3.75 %	3.75 %	3.75 %
Mortality table	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)	Pri-2012 table with MP- 2021 improvement scale (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	Initial and ultimate rate of 5.00%	Initial and ultimate rate of 5.00%	Initial and ultimate rate of 5.00%

(a) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and OPEB costs. Certain benefit plans used individual rates, which range from 5.56%-5.76% and 5.60%-5.64% for pension and OPEB plans, respectively, for the year ended December 31, 2025; 5.11%-5.27% and 5.15%-5.17% for pension and OPEB plans; respectively, for the year ended December 31, 2024; and 5.46%-5.60% and 5.49%-5.51% for pension and OPEB plans, respectively, for the year ended December 31, 2023.
(b) The investment crediting rate above represents a weighted average rate.
(c) Not applicable to pension and OPEB plans that do not have plan assets.

Contributions

Exelon allocates contributions related to its ECRP and PPBU pension plans and East and West OPEB plans to its subsidiaries based on accounting cost. For the EPP pension plan, PHI Qualified, and PHI PRW plans, pension and OPEB contributions are allocated to the subsidiaries based on employee participation (both active and retired). The following table provides contributions to the pension and OPEB plans:

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

	Pension Benefits			OPEB		
	2025	2024	2023	2025	2024	2023
Exelon	$ 293	$ 126	$ 75	$ 49	$ 54	$ 54
ComEd	189	7	24	20	18	17
PECO	11	3	1	2	1	—
BGE	26	17	—	18	20	19
PHI	42	74	8	8	12	16
Pepco	1	1	1	8	8	11
DPL	1	1	2	—	2	2
ACE	4	7	—	—	2	3

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation, and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy to make annual contributions with the objective of achieving 100% funded status on an ABO basis over time. This funding strategy helps minimize volatility of future period required pension contributions. Based on this funding strategy and current market conditions, which are subject to change, Exelon’s estimated annual qualified pension contributions will be approximately $325 million in 2026. Unlike the qualified pension plans, Exelon’s non-qualified pension plans are not funded, given they are not subject to statutory minimum contribution requirements.

While OPEB plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon’s management has historically considered several factors in determining the level of contributions to its OPEB plans, including liabilities management, levels of benefit claims paid, and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.

The following table provides all Registrants planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to OPEB plans in 2026:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 325	$ 19	$ 48
ComEd	217	3	22
PECO	9	1	4
BGE	32	2	14
PHI	48	7	6
Pepco	1	—	6
DPL	1	—	—
ACE	14	—	—

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

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans as of December 31, 2025 were:

	Pension Benefits	OPEB
2026	$ 812	$ 156
2027	816	155
2028	813	154
2029	817	152
2030	807	151
2031 through 2035	3,985	724
Total estimated future benefits payments through 2035	$ 8,050	$ 1,492

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's OPEB plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and OPEB plans. The actual asset returns across Exelon's pension and OPEB plans for the year ended December 31, 2025 were 8.95% and 12.59%, respectively, compared to an expected long-term return assumption of 7.00% and 6.50%, respectively. Exelon used an EROA of 7.00% and 6.50% to estimate its 2026 pension and OPEB costs, respectively.

Exelon's pension and OPEB plan target asset allocations as of December 31, 2025 and 2024 were as follows:

	December 31, 2025		December 31, 2024	
Asset Category	Pension Benefits	OPEB	Pension Benefits	OPEB
Equity securities	24 %	42 %	28 %	44 %
Fixed income securities	43 %	48 %	44 %	41 %
Alternative investments[(a)]	33 %	10 %	28 %	15 %
Total	100 %	100 %	100 %	100 %

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

Concentrations of Credit Risk. Exelon evaluated its pension and OPEB plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2025. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2025, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and OPEB plan assets.

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

Fair Value Measurements

The following tables present pension and OPEB plan assets measured and recorded at fair value in Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2025 and 2024:

	December 31, 2025					December 31, 2024				
	Level 1	Level 2	Level 3	Not Subject to Leveling	Total	Level 1	Level 2	Level 3	Not Subject to Leveling	Total
Pension plan assets[a]										
Cash and cash equivalents	$ 225	$ —	$ —	$ —	$ 225	$ 205	$ —	$ —	$ —	$ 205
Equities[b]	1,113	—	—	1,438	2,551	1,127	—	1	1,361	2,489
Fixed income:										
U.S. Treasury and agencies	1,306	206	—	—	1,512	1,333	199	—	—	1,532
State and municipal debt	—	30	—	—	30	—	32	—	—	32
Corporate debt	—	1,622	12	—	1,634	—	1,551	16	—	1,567
Other[b]	—	223	—	608	831	—	25	—	618	643
Fixed income subtotal	1,306	2,081	12	608	4,007	1,333	1,807	16	618	3,774
Private equity	—	—	17	1,237	1,254	—	—	—	1,249	1,249
Hedge funds	—	—	—	341	341	—	—	—	464	464
Real estate	—	—	—	719	719	—	—	—	730	730
Private credit	—	—	—	539	539	—	—	—	544	544
Pension plan assets subtotal	$ 2,644	$ 2,081	$ 29	$ 4,882	$ 9,636	$ 2,665	$ 1,807	$ 17	$ 4,966	$ 9,455
OPEB plan assets[a]										
Cash and cash equivalents	$ 34	$ —	$ —	$ —	$ 34	$ 44	$ —	$ —	$ —	$ 44
Equities	464	1	—	136	601	437	1	—	188	626
Fixed income:										
U.S. Treasury and agencies	42	31	—	—	73	18	34	—	—	52
State and municipal debt	—	98	—	—	98	—	2	—	—	2
Corporate debt	—	26	—	—	26	—	32	—	—	32
Other	1	21	—	394	416	166	2	—	262	430
Fixed income subtotal	43	176	—	394	613	184	70	—	262	516
Hedge funds	—	—	—	36	36	—	—	—	75	75
Real estate	—	—	—	92	92	—	—	—	78	78
Private credit	—	—	—	13	13	—	—	—	16	16
OPEB plan assets subtotal	$ 541	$ 177	$ —	$ 671	$ 1,389	$ 665	$ 71	$ —	$ 619	$ 1,355
Total pension and OPEB plan assets[c]	$ 3,185	$ 2,258	$ 29	$ 5,553	$ 11,025	$ 3,330	$ 1,878	$ 17	$ 5,585	$ 10,810

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

(a) See Note 15—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Includes derivative instruments of $(12) million and $(21) million for the years ended December 31, 2025 and 2024, respectively, which have total notional amounts of $5,284 million and $5,123 million as of December 31, 2025 and 2024, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of Exelon's exposure to credit or market loss.
(c) Excludes net liabilities of $658 million and $670 million as of December 31, 2025 and 2024, respectively, which include certain derivative assets that have notional amounts of $60 million and $41 million as of December 31, 2025 and 2024, respectively. These items are required to reconcile to the fair value of net plan assets and consist primarily of receivables or payables related to pending securities sales and purchases, interest and dividends receivable, and repurchase agreement obligations. The repurchase agreements generally have maturities ranging from 0 - 6 months.

The following table presents the reconciliation of Level 3 assets and liabilities for Exelon measured at fair value for pension and OPEB plans for the years ended December 31, 2025 and 2024:

	Fixed Income	Equities	Private Equity	Total
Pension Assets				
Balance as of January 1, 2025	$ 16	$ 1	$ —	$ 17
Actual return on plan assets:				
Relating to assets still held as of the reporting date	—	(1)	—	(1)
Purchases, sales and settlements:				
Settlements	(4)	—	—	(4)
Level 3 transfers in	—	—	17	17
Balance as of December 31, 2025	$ 12	$ —	$ 17	$ 29

	Fixed Income	Equities	Private Equity	Total
Pension Assets				
Balance as of January 1, 2024	$ 9	$ 1	$ —	$ 10
Actual return on plan assets:				
Relating to assets still held as of the reporting date	(1)	—	—	(1)
Purchases, sales and settlements:				
Purchases	2	—	—	2
Level 3 transfers in	6	—	—	6
Balance as of December 31, 2024	$ 16	$ 1	$ —	$ 17

Valuation Techniques Used to Determine Fair Value

The techniques used to fair value the pension and OPEB assets invested in cash equivalents are the same as the valuation techniques used to determine the fair value of financial assets. See Cash Equivalents in Note 15 — Fair Value of Financial Assets and Liabilities for further information. Below outlines the techniques used to fair value the pension and OPEB assets invested in equities, fixed income, derivative instruments, private credit, private equity, real estate, and hedge funds.

Equities. These investments consist of individually held equity securities, equity mutual funds, and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights, and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. The equity securities that are held directly by the trust funds are valued based on quoted prices in active markets and categorized as Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and fund investments are held in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds that are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets on the underlying securities and are not classified within the fair value hierarchy. These investments can typically be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Fixed income. Fixed income investments include a broad range of debt securities such as corporate, government, municipal, and asset and mortgage-backed securities, as well as fixed income commingled funds and mutual funds. The trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class, or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments include fixed income commingled funds and mutual funds, which are maintained by investment companies and hold fund investments in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds that are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly or more frequently, with 30 or less days of notice and without further restrictions.

Derivative instruments. These instruments, consisting primarily of futures and swaps to manage risk, are recorded at fair value. Over-the-counter derivatives are valued daily, based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private credit. Private credit investments primarily consist of investments in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Managed private credit fund investments are not classified within the fair value hierarchy because their fair value is determined using NAV or its equivalent as a practical expedient.

Private equity. These investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments, and investments in natural resources. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on Exelon's understanding of the investment funds. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows, and market based comparable data. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy. Includes certain private equity investments previously measured at fair value using NAV or its equivalent as a practical expedient and transferred to Level 3 primarily due to changes in market liquidity or data.

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

Real estate. These investments are funds with a direct investment in pools of real estate properties. These funds are reported by the fund manager and are generally based on independent appraisals of the underlying investments from sources with professional qualifications, typically using a combination of market-based comparable data and discounted cash flows. These valuation inputs are unobservable. Certain real estate investments cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on Exelon's understanding of the investment funds. The remaining liquid real estate investments are generally redeemable from the investment vehicle quarterly, with 30 to 90 days of notice. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

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

Defined Contribution Savings Plan

The Registrants participate in a 401(k) defined contribution savings plan that is sponsored by Exelon. The plan is qualified under applicable sections of the IRC and allows employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the employer contributions and employer matching contributions to the savings plan for the years ended December 31, 2025, 2024, and 2023:

For the Years Ended December 31,	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2025	$ 121	$ 48	$ 16	$ 16	20	$ 5	$ 4	$ 3
2024	112	46	15	12	19	5	5	3
2023	109	47	15	12	16	4	3	2

13. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations. The Registrants do not execute derivatives for speculative or proprietary trading purposes.

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

Commodity Price Risk

The Utility Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, which are either determined to be non-derivative or classified as economic hedges. The Utility Registrants procure electric and natural gas supply through a competitive procurement process approved by each of the respective state utility commissions. The Utility Registrants' hedging programs are intended to reduce exposure to energy and natural gas price volatility and have no direct earnings impact as the costs are fully recovered from customers through regulatory-approved recovery mechanisms. The following table provides a summary of the Utility Registrants' primary derivative hedging instruments, listed by commodity and accounting treatment.

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

Registrant	Commodity	Accounting Treatment	Hedging Instrument
ComEd	Electricity	NPNS	Fixed price contracts based on all requirements in the IPA procurement plans.
	Electricity	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[a]	20-year floating-to-fixed energy swap contracts beginning June 2012 based on the renewable energy resource procurement requirements in the Illinois Settlement Legislation of approximately 1.3 million MWhs per year.
PECO	Electricity	NPNS	Fixed price contracts for default supply requirements through full requirements contracts.
	Gas	NPNS	Fixed price contracts to cover about 10% of planned natural gas purchases in support of projected firm sales.
BGE	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed price purchases associated with forecasted gas supply requirements.
Pepco	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
DPL	Electricity	NPNS	Fixed price contracts for all SOS requirements through full requirements contracts.
	Gas	NPNS	Fixed and index priced contracts through full requirements contracts.
	Gas	Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[b]	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

(a) See Note 2—Regulatory Matters for additional information.
(b) The fair value of the DPL economic hedge is not material as of December 31, 2025 and 2024.

The fair value of derivative economic hedges is presented in Other current assets and current and noncurrent Mark-to-market derivative liabilities in Exelon's and ComEd's Consolidated Balance Sheets.

Interest Rate Risk (Exelon)

Exelon Corporate uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon Corporate may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. A hypothetical 50 basis point change in the interest rates associated with Exelon's interest rate swaps as of December 31, 2025 would result in an immaterial impact to Exelon's Consolidated Net Income.

Below is a summary of the interest rate hedge balances at December 31, 2025 and 2024.

	Derivatives Designated as Hedging Instruments	
	December 31, 2025	December 31, 2024
Other current assets	$ 3	$ 14
Other deferred debits (noncurrent assets)	—	12
Total derivative assets	3	26
Mark-to-market derivative liabilities (current liabilities)	(4)	(1)
Total mark-to-market derivative liabilities	(4)	(1)
Total mark-to-market derivative net (liabilities) assets	$ (1)	$ 25

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

Cash Flow Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as cash flow hedges, the changes in fair value each period are initially recorded in AOCI and reclassified into earnings when the underlying transaction affects earnings. The gains and losses reclassified out of AOCI for the years ended December 31, 2025, 2024, and 2023 are immaterial.

In February 2025, Exelon terminated the previously issued floating-to-fixed swaps with a total notional of $765 million upon issuance of $1 billion of debt. See Note 14 — Debt and Credit Agreements for additional information on the debt issuance. The settlements resulted in a cash receipt of $16 million. The accumulated AOCI gain of $13 million (net of tax) is being amortized into Interest expense in Exelon's Consolidated Statement of Operations and Comprehensive Income over the 5-year and 10-year terms of the swaps. During the fourth quarter of 2025, Exelon Corporate entered into $30 million notional of 10-year maturity floating-to-fixed swaps designated as cash flow hedges. The following table provides the notional amounts outstanding held by Exelon at December 31, 2025 and 2024.

	December 31, 2025	December 31, 2024
5-year maturity floating-to-fixed swaps	$ 335	$ 657
10-year maturity floating-to-fixed swaps	365	658
Total	$ 700	$ 1,315

The AOCI derivative loss (net of tax) was $9 million for the year ended December 31, 2025 and gain was $19 million for the year ended December 31, 2024, respectively. See Note 19 – Changes in Accumulated Other Comprehensive Income (Loss) for additional information.

Credit Risk

The Registrants 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 at the reporting date. The Utility Registrants have contracts to procure electric and natural gas supply that provide suppliers with a certain amount of unsecured credit. If the exposure on the supply contract exceeds the amount of unsecured credit, the suppliers may be required to post collateral. The net credit exposure is mitigated primarily by the ability to recover procurement costs through customer rates. The amount of cash collateral received from external counterparties remained relatively consistent as of December 31, 2025. Cash collateral held by ComEd, PECO, BGE, Pepco, DPL, and ACE must be deposited in an unaffiliated major U.S. commercial or foreign bank with a U.S. branch office that meets certain qualifications. The following table reflects the Registrants' cash collateral held from external counterparties, which is recorded in Other current liabilities on their respective Consolidated Balance Sheets, at December 31, 2025 and 2024

	December 31, 2025	December 31, 2024
Exelon	$ 223	$ 181
ComEd	192	176
PECO[(a)]	6	—
BGE	4	1
PHI	21	4
Pepco	13	1
DPL	3	2
ACE[(a)]	5	—

(a) PECO and ACE had less than one million in cash collateral held with external parties as of December 31, 2024.

The Utility Registrants' electric supply procurement contracts do not contain provisions that would require them to post collateral. PECO's, BGE's, and DPL's natural gas procurement contracts contain provisions that could require PECO, BGE, and DPL to post collateral in the form of cash or credit support, which vary by contract and counterparty, with thresholds contingent upon PECO's, BGE's, and DPL's credit rating. As of December 31, 2025, PECO, BGE, and DPL were not required to post collateral for any of these agreements. If PECO, BGE, or DPL lost their investment grade credit rating as of December 31, 2025, they could have been required to post collateral to their counterparties of $58 million, $43 million, and $14 million, respectively.

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

14. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. PECO meets its short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. Pepco, DPL, and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the PHI intercompany money pool. PHI Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and borrowings from the Exelon intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

Commercial Paper

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements at December 31, 2025 and 2024:

	Credit Facility Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings at December 31,	
Commercial Paper Issuer	**2025[a]**	**2024[a]**	**2025**	**2024**	**2025**	**2024**
Exelon[b]	$ 4,000	$ 4,000	$ 612	$ 1,359	3.94 %	4.66 %
ComEd	$ 1,000	$ 1,000	$ —	$ 36	— %	4.55 %
PECO	$ 600	$ 600	$ —	$ 192	— %	4.65 %
BGE	$ 600	$ 600	$ —	$ 175	— %	4.61 %
PHI[c]	$ 900	$ 900	$ 612	$ 530	3.94 %	4.70 %
Pepco	$ 360 [d]	$ 300	$ 303	$ 200	3.93 %	4.69 %
DPL	$ 300 [d]	$ 300	$ 161	$ 144	3.94 %	4.74 %
ACE	$ 240 [d]	$ 300	$ 148	$ 186	3.94 %	4.67 %

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(a) Excludes credit facility agreements arranged at community banks. See below for additional information.
(b) Includes revolving credit agreements at Exelon Corporate with a maximum program size of $900 million as of December 31, 2025 and December 31, 2024. Exelon Corporate had no outstanding commercial paper as of December 31, 2025 and $426 million outstanding commercial paper as of December 31, 2024.
(c) Represents the consolidated amounts of Pepco, DPL, and ACE.
(d) The standard maximum program size for revolving credit facilities is $300 million each for Pepco, DPL, and ACE based on the credit agreements in place. However, the facilities at Pepco, DPL, and ACE have the ability to flex to $500 million, $500 million, and $350 million, respectively. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL, or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility. This ability was utilized to increase Pepco's program size to $360 million, effective December 11, 2025. As a result, the program size for DPL did not change and ACE was decreased to $240 million, which prevents the aggregate amount of outstanding short-term debt from exceeding the $900 million limit.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. A registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

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

At December 31, 2025, the Registrants had the following aggregate bank commitments, credit facility borrowings, and available capacity under their respective credit facilities:

					Available Capacity at December 31, 2025	
Borrower	Facility Type	Aggregate Bank Commitment[(a)]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper[(b)]
Exelon[(b)]	Syndicated Revolver	$ 4,000	$ —	$ 51	$ 3,949	$ 3,338
ComEd	Syndicated Revolver	1,000	—	15	985	985
PECO	Syndicated Revolver	600	—	5	595	595
BGE	Syndicated Revolver	600	—	25	575	575
PHI[(c)]	Syndicated Revolver	900	—	2	898	286
Pepco	Syndicated Revolver	360	—	2	358	55
DPL	Syndicated Revolver	300	—	—	300	139
ACE	Syndicated Revolver	240	—	—	240	92

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(a) Excludes credit facility agreements arranged at community banks. See below for additional information.
(b) Includes $900 million aggregate bank commitment related to Exelon Corporate. Exelon Corporate had $3 million outstanding letters of credit as of December 31, 2025. Exelon Corporate had $897 million in available capacity to support additional commercial paper as of December 31, 2025.
(c) Represents the consolidated amounts of Pepco, DPL, and ACE.

The following table reflects the Registrants' credit facility agreements arranged at community banks at December 31, 2025 and 2024. These are excluded from the Maximum Program Size and Aggregate Bank Commitment amounts within the two tables above and the facilities may be used to issue letters of credit.

	Aggregate Bank Commitments		Outstanding Letters of Credit	
Borrower	2025[(a)]	2024	2025	2024
Exelon[(b)]	$ 140	$ 140	$ 5	$ 5
ComEd	40	40	3	3
PECO	40	40	—	—
BGE	15	15	2	2
PHI[(c)]	45	45	—	—
Pepco	15	15	—	—
DPL	15	15	—	—
ACE	15	15	—	—

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(a) These facilities were entered into on October 3, 2025 and expire on October 1, 2027. Previously structured as one-year arrangements, the facilities are now two-year terms.
(b) Represents the consolidated amounts of ComEd, PECO, BGE, Pepco, DPL, and ACE.
(c) Represents the consolidated amounts of Pepco, DPL, and ACE.

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

Revolving Credit Agreements

On August 29, 2024, Exelon Corporate and each of the Utility Registrants amended and restated their respective syndicated revolving credit facility, extending the maturity date to August 29, 2029. The following table reflects the credit agreements:

Borrower	Aggregate Bank Commitment	Interest Rate
Exelon Corporate	$ 900	SOFR plus 1.075%
ComEd	$ 1,000	SOFR plus 1.000%
PECO	$ 600	SOFR plus 0.900%
BGE	$ 600	SOFR plus 0.900%
Pepco	$ 300	SOFR plus 1.000%
DPL	$ 300	SOFR plus 1.000%
ACE	$ 300	SOFR plus 1.000%

Borrowings under Exelon’s, ComEd’s, PECO’s, BGE's, Pepco's, DPL's, and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a SOFR-based rate, plus an adder based upon the particular Registrant’s credit rating. The adders for the prime based borrowings and SOFR-based borrowings as of December 31, 2025 are presented in the following table:

	Exelon[(a)]	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	0 - 7.5	—	—	—	—	—	—
SOFR-based borrowings	90.0 - 107.5	100.0	90.0	90.0	100.0	100.0	100.0

(a) Includes interest rate adders at Exelon Corporate of 7.5 basis points and 107.5 basis points for prime and SOFR-based borrowings, respectively.

If any Registrant loses its investment grade rating, the maximum adders for prime rate borrowings and SOFR-based rate borrowings would be 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower. Exelon Corporate and the Utility Registrants had no outstanding amounts on the revolving credit facilities as of December 31, 2025.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million. The loan agreement was renewed in the first quarter of 2024 and was bifurcated into two tranches of $350 million and $150 million on March 14, 2024. The loan agreements were renewed in the first quarter of 2025, extending the expiration date to March 13, 2026 with a variable interest rate equal to SOFR plus 1.00%. Exelon Corporate repaid the term loan on December 5, 2025.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, these bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, PHI views VRDBs as a source of long-term financing. As of December 31, 2025 and December 31, 2024, $46 million and $46 million in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year in Exelon's, PHI's, and DPL's Consolidated Balance Sheets.

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

Long-Term Debt

The following tables present the outstanding long-term debt at the Registrants at December 31, 2025 and 2024:

Exelon

	Rates		Maturity Date	December 31, 2025	December 31, 2024
Long-term debt					
First mortgage bonds[a]	2.20 % -	7.90 %	2026 - 2055	$ 28,376	$ 26,451
Senior unsecured notes	2.75 % -	7.60 %	2026 - 2055	13,473	12,280
Unsecured notes	2.25 % -	6.35 %	2026 - 2054	6,100	5,450
Notes payable and other	1.64 % -	7.49 %	2025 - 2053	79	83
Junior subordinated notes		6.50 %	2055	1,000	—
Long-term software licensing agreement		2.30 %	2025	—	4
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Total long-term debt				49,038	44,278
Unamortized debt discount and premium, net				(93)	(94)
Unamortized debt issuance costs				(369)	(326)
Fair value adjustment				502	542
Long-term debt due within one year				(1,665)	(1,453)
Long-term debt				$ 47,413	$ 42,947
Long-term debt to financing trusts[b]					
Subordinated debentures to ComEd Financing III		6.35 %	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38 % -	8.75 %	2028	81	81
Subordinated debentures to PECO Trust IV		5.75 %	2033	103	103
Total long-term debt to financing trusts				$ 390	$ 390

(a) Substantially all of ComEd's assets other than expressly excluded property and substantially all of PECO's, Pepco's, DPL's, and ACE's assets are subject to the liens of their respective mortgage indentures.
(b) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon's Consolidated Balance Sheets.

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

ComEd

	Rates	Maturity Date	December 31, 2025	December 31, 2024
Long-term debt				
First mortgage bonds[(a)]	2.20 % - 6.45 %	2026 - 2055	$ 12,879	$ 12,154
Other	7.49 %	2053	7	8
Total long-term debt			12,886	12,162
Unamortized debt discount and premium, net			(29)	(31)
Unamortized debt issuance costs			(104)	(101)
Long-term debt due within one year			(500)	—
Long-term debt			$ 12,253	$ 12,030
Long-term debt to financing trust[(b)]				
Subordinated debentures to ComEd Financing III	6.35 %	2033	$ 206	$ 206
Long-term debt to financing trusts			$ 206	$ 206

(a) Substantially all of ComEd's assets, other than expressly excluded property, are subject to the lien of its mortgage indenture.
(b) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.

PECO

	Rates	Maturity Date	December 31, 2025	December 31, 2024
Long-term debt				
First mortgage bonds[(a)]	2.80 % - 5.95 %	2033 - 2055	$ 6,475	$ 5,775
Total long-term debt			6,475	5,775
Unamortized debt discount and premium, net			(25)	(25)
Unamortized debt issuance costs			(54)	(46)
Long-term debt due within one year			—	(350)
Long-term debt			$ 6,396	$ 5,354
Long-term debt to financing trusts[(b)]				
Subordinated debentures to PECO Trust III	7.38 % - 8.75 %	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75 %	2033	103	103
Long-term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

BGE

	Rates	Maturity Date	December 31, 2025	December 31, 2024
Long-term debt				
Unsecured notes	2.25 % - 6.35 %	2026 - 2054	$ 6,100	$ 5,450
Total long-term debt			6,100	5,450
Unamortized debt discount and premium, net			(14)	(13)
Unamortized debt issuance costs			(45)	(42)
Long-term debt due within one year			(350)	—
Long-term debt			$ 5,691	$ 5,395

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

PHI

	Rates		Maturity Date	December 31, 2025	December 31, 2024
Long-term debt					
First mortgage bonds[a]	2.25 % -	7.90 %	2028 - 2055	$ 9,022	$ 8,522
Senior unsecured notes		7.45 %	2032	185	185
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Finance leases		5.62 %	2026 - 2033	72	75
Total long-term debt				9,289	8,792
Unamortized debt discount and premium, net				(2)	(2)
Unamortized debt issuance costs				(71)	(66)
Fair value adjustment				374	400
Long-term debt due within one year				(64)	(290)
Long-term debt				$ 9,526	$ 8,834

(a) Substantially all of Pepco's, DPL's, and ACE's assets are subject to the liens of their respective mortgage indentures.

Pepco

	Rates		Maturity Date	December 31, 2025	December 31, 2024
Long-term debt					
First mortgage bonds[a]	2.32 % -	7.90 %	2029 - 2055	$ 4,675	$ 4,400
Finance leases		5.62 %	2026 - 2033	25	27
Total long-term debt				4,700	4,427
Unamortized debt discount and premium, net				(1)	—
Unamortized debt issuance costs				(67)	(65)
Long-term debt due within one year				(6)	(6)
Long-term debt				$ 4,626	$ 4,356

(a) Substantially all of Pepco's assets are subject to the lien of its mortgage indenture.

DPL

	Rates		Maturity Date	December 31, 2025	December 31, 2024
Long-term debt					
First mortgage bonds[a]	2.53 % -	5.72 %	2028 - 2054	$ 2,324	$ 2,198
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Finance leases		5.62 %	2026 - 2033	27	28
Total long-term debt				2,361	2,236
Unamortized debt issuance costs				(17)	(16)
Long-term debt due within one year				(53)	(130)
Long-term debt				$ 2,291	$ 2,090

(a) Substantially all of DPL's assets are subject to the lien of its mortgage indenture.

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

ACE

	Rates		Maturity Date	December 31, 2025	December 31, 2024
Long-term debt					
First mortgage bonds[a]	2.25 % -	5.81 %	2028 - 2055	$ 2,023	$ 1,923
Finance leases		5.62 %	2026 - 2033	20	20
Total long-term debt				2,043	1,943
Unamortized debt issuance costs				(10)	(10)
Long-term debt due within one year				(5)	(154)
Long-term debt				$ 2,028	$ 1,779

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(a) Substantially all of ACE's assets are subject to the lien of its mortgage indenture.

Long-term debt maturities at the Registrants in the periods 2026 through 2030 and thereafter are as follows:

Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2026	$ 1,665	$ 500	$ —	$ 350	$ 64	$ 6	$ 53	$ 5
2027	1,028	350	—	—	28	7	17	5
2028	1,996	550	81	—	365	5	6	354
2029	1,933	—	—	—	284	153	4	126
2030	1,856	350	—	—	257	153	103	2
Thereafter	40,950 [a]	11,342 [b]	6,578 [c]	5,750	8,291	4,376	2,178	1,551
Total	$ 49,428	$ 13,092	$ 6,659	$ 6,100	$ 9,289	$ 4,700	$ 2,361	$ 2,043

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(a) Includes $390 million due to ComEd and PECO financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.

Convertible Senior Notes

On December 4, 2025, Exelon Corporation issued $1 billion aggregate principal amount of 3.25% Convertible Senior Notes due 2029 (Convertible Senior Notes). The Convertible Senior Notes are reflected as Long-term debt on Exelon's Consolidated Balance Sheet.

The Convertible Senior Notes are senior, unsecured notes that bear interest at a fixed rate of 3.25% per year, payable semiannually in arrears on March 15 and September 15 of each year, beginning on September 15, 2026. The Convertible Senior Notes will mature on March 15, 2029, unless earlier converted or repurchased in accordance with their terms.

Under the following circumstances, holders may convert the Convertible Senior Notes at their option prior to the close of business on the business day preceding December 15, 2028:

- during any calendar quarter beginning after the quarter ending on March 31, 2026, if the last reported sale price of Exelon's common stock for at least 20 trading days (whether consecutive or not) during the period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal the stock was trading at greater than or equal to 130% of the conversion price on each applicable trading day as determined by Exelon;
- during the five business day period after any ten consecutive trading day period (measurement period) in which the applicable trading price per $1,000 principal amount of notes for each trading day of the measurement period was less than 98% of the product of the last reported sale price of the common stock and the conversion rate on each such trading day;
- upon the occurrence of certain corporate events specified in the respective supplemental indentures governing the Convertible Senior Notes.

On or after December 15, 2028, a holder may convert for all, or any portion of its Convertible Senior Notes at any time prior to the close of business on the business day immediately preceding the applicable maturity date regardless of the foregoing conditions.

Exelon will settle conversions of the Convertible Senior Notes by paying cash up to the aggregate principal amount to be converted and paying or delivering, as the case may be, cash, shares of common stock, or a combination of cash and shares of common stock, at Exelon’s discretion, in respect of the remainder, if any, of Exelon's conversion obligation in excess of the aggregate principal amount of the Convertible Senior Notes being converted. The Convertible Senior Notes are initially convertible at 17.5093 shares per $1,000 principal amount, which is equivalent to an initial conversion price of approximately $57.11 per share of common stock. The initial conversion price of the Convertible Senior Notes represents a premium of approximately 25% over the last reported sale price of Exelon’s common stock on the Nasdaq Global Select Market on December 1, 2025. These conversions will be subject to adjustment upon the occurrence of certain specified events but will not be adjusted for accrued and unpaid interest. In addition, upon the occurrence of a make-whole fundamental change (as defined in the indenture) Exelon will, in certain circumstances, increase the applicable conversion rate by a number of additional shares of common stock for conversions in connection with the make-whole fundamental change.

EPS Impact

Diluted earnings per common shares will also reflect the dilutive effect of potential common shares from share-based awards and convertible notes. The dilutive effect of the Convertible Senior Notes is computed using the if-converted method. For the year ended December 31, 2025, no incremental shares were assumed converted or included in the diluted earnings per common share. resulting from the Convertible Senior Notes.

Debt Extinguishment

During the twelve months ended December 31, 2024, Exelon repurchased a portion of its Senior unsecured notes with a principal balance of $244 million outstanding in exchange for cash of $215 million. The repurchase was accounted for as a debt extinguishment and resulted in a pre-tax gain of $28 million, which is reflected on Exelon's Consolidated Statement of Operations and Comprehensive income within Interest expense, net.

Reoffering of Tax-Exempt Bonds

On July 1, 2025, DPL completed the reoffering of $78.4 million aggregate principal amount of its Delaware Economic Development Authority’s Gas Facilities Refunding Revenue Bonds (Delmarva Power & Light Company Project) 2020 Series A (Non-AMT) (the Bonds). In connection with the reoffering of the Bonds, the interest rate was modified to 3.60% per annum, and the maturity date was modified to January 1, 2031. DPL did not directly receive any proceeds from the reoffering.

Debt Covenants

As of December 31, 2025, the Registrants are in compliance with debt covenants.

15. Fair Value of Financial Assets and Liabilities (All Registrants)

Exelon measures and classifies 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 the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

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

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) at December 31, 2025 and 2024. The Registrants have no financial liabilities measured using the NAV practical expedient.

The carrying amounts of the Registrants' short-term liabilities as presented in their Consolidated Balance Sheets are representative of their fair value (Level 2) because of the short-term nature of these instruments.

	December 31, 2025					December 31, 2024				
	Carrying Amount	Fair Value				Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total		Level 1	Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]										
Exelon [(b)]	$49,078	$ —	$ 40,637	$ 4,318	$ 44,955	$44,400	$ —	$35,337	$3,720	$39,057
ComEd	12,753	—	11,291	—	11,291	12,030	—	10,260	—	10,260
PECO	6,396	—	5,593	—	5,593	5,704	—	4,816	—	4,816
BGE	6,041	—	5,510	—	5,510	5,395	—	4,702	—	4,702
PHI	9,590	—	4,236	4,318	8,554	9,124	—	4,093	3,720	7,813
Pepco	4,632	—	2,546	1,861	4,407	4,362	—	2,475	1,544	4,019
DPL	2,344	—	657	1,410	2,067	2,220	—	623	1,250	1,873
ACE	2,033	—	819	1,047	1,866	1,933	—	787	925	1,712
Long-Term Debt to Financing Trusts										
Exelon	$ 390	$ —	$ —	$ 403	$ 403	$ 390	$ —	$ —	$ 396	$ 396
ComEd	206	—	—	216	216	206	—	—	208	208
PECO	184	—	—	187	187	184	—	—	188	188

(a) Includes unamortized debt issuance costs, unamortized debt discount and premium, net, purchase accounting fair value adjustments, and finance lease liabilities which are not fair valued. Refer to Note 14 — Debt and Credit Agreements for unamortized debt issuance costs, unamortized debt discount and premium, net, and purchase accounting fair value adjustments and Note 9 — Leases for finance lease liabilities.

(b) Includes the net carrying amount and the estimated fair value (Level 2) of the Convertible Senior Notes of $988 million and $1 billion for the year ended December 31, 2025, respectively.

Exelon uses the following methods and assumptions to estimate fair value of financial liabilities recorded at carrying cost:

Type	Level	Registrants	Valuation
Long-Term Debt, including amounts due within one year			
Taxable Debt Securities	2	All	The fair value is determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. Exelon obtains credit spreads based on trades of existing Exelon debt securities as well as other issuers in the utility sector with similar credit ratings. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.
Variable Rate Financing Debt	2	Exelon, DPL	Debt rates are reset on a regular basis and the carrying value approximates fair value.
Non-Government Backed Fixed Rate Nonrecourse Debt	2	Exelon	Fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project.
Taxable Private Placement Debt Securities	3	Exelon, Pepco, DPL, ACE	Rates are obtained similar to the process for taxable debt securities. Due to low trading volume and qualitative factors such as market conditions, low volume of investors, and investor demand, these debt securities are Level 3.
Long-Term Debt to Financing Trusts			
Long Term Debt to Financing Trusts	3	Exelon, ComEd, PECO	Fair value is based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities and qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

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

Recurring Fair Value Measurements

The following tables present assets and liabilities measured and recorded at fair value in the Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2025 and 2024. Exelon and the Utility Registrants have immaterial and no financial assets or liabilities measured using the NAV practical expedient, respectively.

Exelon

	At December 31, 2025				At December 31, 2024			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$ 825	$ —	$ —	$ 825	$ 544	$ —	$ —	$ 544
Rabbi trust investments								
Cash equivalents	101	—	—	101	94	—	—	94
Mutual funds	71	—	—	71	65	—	—	65
Fixed income	—	6	—	6	—	6	—	6
Life insurance contracts	—	79	21	100	—	73	22	95
Rabbi trust investments subtotal	172	85	21	278	159	79	22	260
Interest rate derivative assets								
Derivatives designated as hedging instruments	—	3	—	3	—	26	—	26
Interest rate derivative assets subtotal	—	3	—	3	—	26	—	26
Total assets	997	88	21	1,106	703	105	22	830
Liabilities								
Commodity derivative liabilities	—	—	(131)	(131)	—	—	(132)	(132)
Interest rate derivative liabilities								
Derivatives designated as hedging instruments	—	(4)	—	(4)	—	(1)	—	(1)
Interest rate derivative liabilities subtotal	—	(4)	—	(4)	—	(1)	—	(1)
Deferred compensation obligation	—	(71)	—	(71)	—	(74)	—	(74)
Total liabilities	—	(75)	(131)	(206)	—	(75)	(132)	(207)
Total net assets (liabilities)	$ 997	$ 13	$ (110)	$ 900	$ 703	$ 30	$ (110)	$ 623

(a) Excludes cash of \$180 million and \$219 million at December 31, 2025 and 2024, respectively, and restricted cash of \$196 million and \$176 million at December 31, 2025 and 2024, respectively, and includes long-term restricted cash of \$50 million and \$41 million at December 31, 2025 and 2024, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

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

ComEd, PECO, and BGE

	ComEd				PECO				BGE			
At December 31, 2025	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 393	$ —	$ —	$ 393	$ 93	$ —	$ —	$ 93	$ 205	$ —	$ —	$ 205
Rabbi trust investments												
Mutual funds	—	—	—	—	13	—	—	13	10	—	—	10
Life insurance contracts	—	—	—	—	—	25	—	25	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	13	25	—	38	10	—	—	10
Total assets	393	—	—	393	106	25	—	131	215	—	—	215
Liabilities												
Commodity derivative liabilities[(b)]	—	—	(131)	(131)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(9)	—	(9)	—	(8)	—	(8)	—	(4)	—	(4)
Total liabilities	—	(9)	(131)	(140)	—	(8)	—	(8)	—	(4)	—	(4)
Total net assets (liabilities)	$ 393	$ (9)	$ (131)	$ 253	$ 106	$ 17	$ —	$ 123	$ 215	$ (4)	$ —	$ 211

	ComEd				PECO				BGE			
At December 31, 2024	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 390	$ —	$ —	$ 390	$ 29	$ —	$ —	$ 29	$ 1	$ —	$ —	$ 1
Rabbi trust investments												
Mutual funds	—	—	—	—	12	—	—	12	10	—	—	10
Life insurance contracts	—	—	—	—	—	22	—	22	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	12	22	—	34	10	—	—	10
Total assets	390	—	—	390	41	22	—	63	11	—	—	11
Liabilities												
Commodity derivative liabilities[(b)]	—	—	(132)	(132)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(7)	—	(7)	—	(4)	—	(4)
Total liabilities	—	(8)	(132)	(140)	—	(7)	—	(7)	—	(4)	—	(4)
Total net assets (liabilities)	$ 390	$ (8)	$ (132)	$ 250	$ 41	$ 15	$ —	$ 56	$ 11	$ (4)	$ —	$ 7

(a) ComEd excludes cash of $77 million and $66 million at December 31, 2025 and 2024, respectively, and restricted cash of $193 million and $176 million at December 31, 2025 and 2024, respectively, and includes long-term restricted cash of $50 million and $41 million at December 31, 2025 and 2024, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $23 million and $19 million at December 31, 2025 and 2024, respectively. BGE excludes cash of $15 million and $33 million at December 31, 2025 and 2024, respectively.

(b) The Level 3 balance consists of the current and noncurrent liability of $25 million and $106 million, respectively, at December 31, 2025, and $29 million and $103 million, respectively, at December 31, 2024 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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

PHI, Pepco, DPL, and ACE

	At December 31, 2025				At December 31, 2024			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 83	$ —	$ —	$ 83	$ 93	$ —	$ —	$ 93
Rabbi trust investments								
Cash equivalents	99	—	—	99	92	—	—	92
Mutual funds	9	—	—	9	9	—	—	9
Fixed income	—	6	—	6	—	6	—	6
Life insurance contracts	—	23	20	43	—	23	21	44
Rabbi trust investments subtotal	108	29	20	157	101	29	21	151
Total assets	191	29	20	240	194	29	21	244
Liabilities								
Deferred compensation obligation	—	(9)	—	(9)	—	(12)	—	(12)
Total liabilities	—	(9)	—	(9)	—	(12)	—	(12)
Total net assets	$ 191	$ 20	$ 20	$ 231	$ 194	$ 17	$ 21	$ 232

	Pepco				DPL				ACE			
At December 31, 2025	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 33	$ —	$ —	$ 33	$ 3	$ —	$ —	$ 3	$ —	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	98	—	—	98	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	20	43	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	98	23	20	141	—	—	—	—	—	—	—	—
Total assets	131	23	20	174	3	—	—	3	—	—	—	—
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	$ 131	$ 22	$ 20	$ 173	$ 3	$ —	$ —	$ 3	$ —	$ —	$ —	$ —

	Pepco				DPL				ACE			
At December 31, 2024	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 21	$ —	$ —	$ 21	$ 3	$ —	$ —	$ 3	$ —	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	91	—	—	91	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	21	44	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	91	23	21	135	—	—	—	—	—	—	—	—
Total assets	112	23	21	156	3	—	—	3	—	—	—	—
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	$ 112	$ 22	$ 21	$ 155	$ 3	$ —	$ —	$ 3	$ —	$ —	$ —	$ —

(a) PHI excludes cash of $56 million and $70 million at December 31, 2025 and 2024, respectively, and restricted cash of $2 million and zero at December 31, 2025 and 2024, respectively. Pepco excludes cash of $22 million and $30 million at December 31, 2025 and 2024, respectively. DPL excludes cash of $9 million and $20 million at December 31, 2025 and 2024, respectively. ACE excludes cash of $22 million and $14 million at December 31, 2025 and 2024, respectively, and restricted cash of $2 million and zero at December 31, 2025 and 2024, respectively.

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

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2025 and 2024:

	Exelon	ComEd	PHI and Pepco
For the year ended December 31, 2025	Total	Commodity Derivatives	Life Insurance Contracts
Balance at December 31, 2024	$ (110)	$ (132)	$ 21
Total realized / unrealized gains (losses)			
Included in net income[(a)]	1	—	1
Included in regulatory assets/liabilities[(b)]	1	1	—
Settlements	(2)	—	(2)
Balance at December 31, 2025[(c)]	$ (110)	$ (131)	$ 20
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2025	$ 1	$ —	$ 1

	Exelon	ComEd	PHI and Pepco
For the year ended December 31, 2024	Total	Commodity Derivatives	Life Insurance Contracts
Balance at December 31, 2023	$ (90)	$ (133)	$ 41
Total realized / unrealized gains (losses)			
Included in net income[(a)]	1	—	2
Included in regulatory assets/liabilities [(b)]	1	1	—
Settlements	(22)	—	(22)
Balance at December 31, 2024[(c)]	$ (110)	$ (132)	$ 21
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2024	$ 1	$ —	$ 2

(a) Classified in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.
(b) For ComEd, this includes $45 million of decreases in fair value and an increase for realized gains due to settlements of $46 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2025. Includes $40 million of decreases in fair value and an increase for realized gains due to settlements of $40 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2024.
(c) For ComEd, the balance of the current and noncurrent asset was zero as of December 31, 2025. The balance consists of a current and noncurrent liability of $25 million and $106 million, respectively, as of December 31, 2025.

Valuation Techniques Used to Determine Fair Value

Cash Equivalents (All Registrants). Investments with original maturities of three months or less when purchased, including mutual and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Rabbi Trust Investments (Exelon, PECO, BGE, PHI, and Pepco). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts' assets are included in Investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities, and life insurance policies. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3, where the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Therefore, Exelon has not disclosed such inputs.

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

Interest Rate Derivatives (Exelon). Exelon may utilize fixed-to-floating or floating-to-fixed interest rate swaps as a means to manage interest rate risk and to lock in interest levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized as Level 2 in the fair value hierarchy. See Note 13 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

Deferred Compensation Obligations (All Registrants). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Commodity Derivatives (Exelon and ComEd). On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and the internal modeling assumptions. The modeling assumptions include using forward power prices. See Note 13 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

The following table discloses the significant unobservable inputs to the forward curve used to value mark-to-market derivatives:

Type of trade	Fair Value as of December 31, 2025	Fair Value as of December 31, 2024	Valuation Technique	Unobservable Input	2025 Range & Arithmetic Average		2024 Range & Arithmetic Average	
Commodity derivatives	$ (131)	$ (132)	Discounted Cash Flow	Forward power price[(a)]	$29.75 - $61.84	$41.95	$30.31 - $59.88	$42.08

(a) An increase to the forward power price would increase the fair value.

16. Commitments and Contingencies (All Registrants)

Commitments

PHI Merger Commitments (Exelon, PHI, Pepco, DPL, and ACE). Approval of the PHI Merger in Delaware, New Jersey, Maryland, and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments. The following amounts represent total commitment costs that have been recorded since the acquisition date and the total remaining obligations for Exelon, PHI, Pepco, DPL, and ACE at December 31, 2025:

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

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	22	20	20	—	—

(a) Remaining commitments extend through 2026 and include escrow funds, charitable contributions, and rate credits.

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

Commercial Commitments (All Registrants). The Registrants' commercial commitments at December 31, 2025, representing commitments potentially triggered by future events were as follows:

		Expiration within					
Exelon	**Total**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031 and beyond**
Letters of credit[a]	$ 56	$ 54	$ 2	$ —	$ —	$ —	$ —
Surety bonds[b]	279	199	2	78	—	—	—
Financing trust guarantees[c]	378	—	—	78	—	—	300
Guaranteed lease residual values[d]	24	—	4	6	4	4	6
Total commercial commitments	$ 737	$ 253	$ 8	$ 162	$ 4	$ 4	$ 306
ComEd							
Letters of credit[a]	$ 18	$ 16	$ 2	$ —	$ —	$ —	$ —
Surety bonds[b]	42	40	2	—	—	—	—
Financing trust guarantees[c]	200	—	—	—	—	—	200
Total commercial commitments	$ 260	$ 56	$ 4	$ —	$ —	$ —	$ 200
PECO							
Letters of credit[a]	$ 5	$ 5	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	2	2	—	—	—	—	—
Financing trust guarantees[c]	178	—	—	78	—	—	100
Total commercial commitments	$ 185	$ 7	$ —	$ 78	$ —	$ —	$ 100
BGE							
Letters of credit[a]	$ 27	$ 27	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	3	3	—	—	—	—	—
Total commercial commitments	$ 30	$ 30	$ —	$ —	$ —	$ —	$ —
PHI							
Letters of credit[a]	$ 4	$ 4	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	173	95	—	78	—	—	—
Guaranteed lease residual values[d]	24	—	4	6	4	4	6
Total commercial commitments	$ 201	$ 99	$ 4	$ 84	$ 4	$ 4	$ 6
Pepco							
Letters of credit[a]	$ 2	$ 2	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	160	82	—	78	—	—	—
Guaranteed lease residual values[d]	8	—	1	2	1	2	2
Total commercial commitments	$ 170	$ 84	$ 1	$ 80	$ 1	$ 2	$ 2
DPL							
Letters of credit[a]	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	7	7	—	—	—	—	—
Guaranteed lease residual values[d]	9	—	2	2	2	1	2
Total commercial commitments	$ 17	$ 8	$ 2	$ 2	$ 2	$ 1	$ 2
ACE							
Letters of credit[a]	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	6	6	—	—	—	—	—
Guaranteed lease residual values[d]	7	—	1	2	1	1	2
Total commercial commitments	$ 14	$ 7	$ 1	$ 2	$ 1	$ 1	$ 2

____
(a) Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds. Historically, payments under the guarantees have not been made and the likelihood of payments being required is remote.
(c) Reflects guarantee of ComEd and PECO securities held by ComEd Financing III, PECO Trust III, and PECO Trust IV.
(d) Represents the maximum potential obligation in the event the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The lease term associated with these assets ranges from 1 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $54 million guaranteed by Exelon and PHI, of which $18 million, $20 million, and $16 million is guaranteed by Pepco, DPL, and ACE, respectively. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Environmental Remediation Matters

General (All Registrants). The Registrants' 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, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future. Unless otherwise disclosed, the Registrants cannot reasonably estimate whether they will incur significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies, or others, or whether such costs will be recoverable from third parties, including customers. Additional costs could have a material, unfavorable impact on the Registrants' financial statements.

MGP Sites (All Registrants). ComEd, PECO, BGE, and DPL have identified sites where former MGP or gas purification activities have or may have resulted in actual site contamination. For some sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has 16 sites currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2033.
- PECO has 6 sites currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2030.
- BGE has 4 sites currently requiring some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2026.
- DPL has 1 site currently under study and the required cost at the site is not expected to be material.

The historical nature of the MGP and gas purification sites, and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to performing of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

ComEd, pursuant to an ICC order, and PECO, pursuant to a PAPUC order, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. While BGE and DPL do not have riders for MGP clean-up costs, they have historically received recovery of actual clean-up costs in distribution rates.

In 2025, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. ComEd's study resulted in a $12 million increase to the environmental liability and related Regulatory asset, primarily due to increased costs resulting from inflation, adjustments to unit costs, and changes in remediation plans. PECO's study resulted in a $2 million decrease to the environmental liability and related Regulatory asset, primarily due to decreased costs resulting from changes in remediation plans.

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

At December 31, 2025 and 2024, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Accrued expenses, Other current liabilities, and Other deferred credits and other liabilities in their respective Consolidated Balance Sheets:

	December 31, 2025		December 31, 2024	
	Total Environmental Investigation and Remediation Liabilities	Portion of Total Related to MGP Investigation and Remediation	Total Environmental Investigation and Remediation Liabilities	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 386	$ 321	$ 403	$ 322
ComEd	289	289	285	284
PECO	23	22	29	28
BGE	13	10	13	10
PHI	57	—	75	—
Pepco	55	—	73	—
DPL	1	—	1	—
ACE	1	—	1	—

Benning Road Site (Exelon, PHI, and Pepco). In September 2010, PHI received a letter from the EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site, which is owned by Pepco, was formerly the location of an electric generating facility owned by Pepco subsidiary, Pepco Energy Services (PES), which became a part of Constellation following the 2016 merger between PHI and Exelon. This generating facility was deactivated in June 2012. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. In December 2011, the U.S. District Court for the District of Columbia approved a Consent Decree entered into by Pepco and Pepco Energy Services (hereinafter Pepco Entities) with the DOEE, which requires the Pepco Entities to conduct a Remedial Investigation and Feasibility Study (RI/FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The purpose of this RI/FS is to define the nature and extent of contamination from the Benning Road site and to evaluate remedial alternatives.

Pursuant to an internal agreement between the Pepco Entities, since 2013, Pepco has performed the work required by the Consent Decree and has been reimbursed for that work by an agreed upon allocation of costs between the Pepco Entities. In September 2019, the Pepco Entities issued a draft “final” RI report which the DOEE approved on February 3, 2020. In October 2022, the DOEE approved dividing the work to complete the landside portion of the FS from the waterside portion to expedite the overall schedule for completion of the project. The landside FS was approved by the DOEE on March 15th, 2024, and the waterside FS was approved by the DOEE on December 16, 2024. The DOEE and Pepco entered into an addendum to the Benning Consent Decree pursuant to which Pepco has agreed to fund or perform the remedial actions to be selected by the DOEE for the landside and waterside areas. This addendum to the Benning Consent Decree was entered by the Court on February 27, 2024 and became effective on that date. Pepco drafted separate proposed plans for the landside and waterside areas, which were approved and issued by the DOEE for public comment on December 16, 2024 and September 4, 2025, respectively. The public comment period for the landside and waterside areas closed on April 18, 2025 and October 31, 2025, respectively. Pepco submitted a matrix of proposed responses to the public comments and a proposed Record of Decision (ROD) to the DOEE for the landside area on August 15, 2025. Following the close of the waterside area comment period, Pepco will submit a matrix of proposed responses to the public comments and a proposed ROD to the DOEE for the waterside area. The DOEE will issue RODs identifying the remedial actions determined to be necessary for the landside and waterside areas, which will be implemented by Pepco in accordance with the Benning Consent Decree.

As part of the separation between Exelon and Constellation in February 2022, the internal agreement between the Pepco Entities for completion and payment for the remaining Consent Decree work was memorialized in a formal agreement for post-separation activities. A second post-separation assumption agreement between Exelon and Constellation transferred any of the potential remaining remediation liability, if any, of PES/ Constellation to a non-utility subsidiary of Exelon which going forward will be responsible for those liabilities.

Exelon, PHI, and Pepco have determined that a loss associated with this matter is probable and have accrued an estimated liability, which is included in the table above.

Anacostia River Tidal Reach (Exelon, PHI, and Pepco). Contemporaneous with the Benning Road site RI/FS being performed by the Pepco Entities, the DOEE and NPS have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-District of Columbia boundary line to the confluence of the Anacostia and Potomac Rivers. The riverwide RI incorporated the results of the river sampling performed by the Pepco Entities as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by the DOEE’s contractor.

On September 30, 2020, the DOEE released its Interim ROD for the Anacostia River sediments. The Interim ROD reflects an adaptive management approach which will require several identified “hot spots” in the river to be addressed first while continuing to conduct studies and to monitor the river to evaluate improvements and determine potential future remediation plans. The adaptive management process chosen by the DOEE is less intrusive, provides more long-term environmental certainty, is less costly, and allows for site specific remediation plans already underway, including the plan for the Benning Road site to proceed to conclusion.

On July 15, 2022, Pepco received a letter from the District of Columbia's Office of the Attorney General (D.C. OAG) on behalf of the DOEE conveying a settlement offer to resolve all PRPs' liability to the District of Columbia (District) for their past costs and their anticipated future costs to complete the work for the Interim ROD. Pepco responded on July 27, 2022 agreeing to enter into settlement discussions. Pepco and the District entered into another consent decree (the “Anacostia River Consent Decree”) pursuant to which Pepco agreed to pay $47 million to resolve its liability to the District for all past costs to perform the riverwide RI/FS and all future costs to complete the work required by the Interim ROD. This amount was agreed to be paid in four equal annual installments beginning a year after the effective date of the Anacostia River Consent Decree. Pepco paid the first installment of $12 million on April 9, 2025. The funds were deposited into the DOEE’s Clean Land Fund for the District’s costs of the Interim ROD work. The Anacostia River Consent Decree caps Pepco’s liability for these costs and provides Pepco with the right to seek contributions from other PRPs. The Anacostia River Consent Decree was signed by the judge for the U.S. District Court for the District of Columbia and became effective on April 11, 2024. Exelon, PHI, and Pepco have accrued a liability for Pepco’s payment obligations under the Anacostia Consent Decree and management's best estimate of its share of any other future Anacostia River response costs. Pepco has concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

In addition to the activities associated with the remedial process outlined above, CERCLA separately requires federal and state (here including Washington, D.C.) Natural Resource Trustees (federal or state agencies designated by the President or the relevant state, respectively, or Indian tribes) to conduct an assessment of any damages to natural resources within their jurisdiction as a result of the contamination that is being remediated. The Trustees can seek compensation from responsible parties for such damages, including restoration costs. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of a NRD assessment, a process that often takes many years beyond the remedial decision to complete. Pepco has concluded that a loss associated with the eventual NRD assessment is reasonably possible. Due to the early stage of the NRD process, Pepco cannot reasonably estimate the final range of loss potentially resulting from this process. Pepco has become aware, however, that the District is pursuing claims against other parties. Specifically, in January 2025, D.C. OAG filed a lawsuit against the United States seeking to declare the United States liable under CERCLA and the District of Columbia’s Brownfield Revitalization Act of 2000 and to recover the District’s response costs associated with its investigation and remediation of Anacostia River sediment contamination and for future NRDs. Pepco is not a party to this suit, but Pepco, the United States, and the District of Columbia have entered mediation discussions to resolve their respective claims against one another under CERCLA and the Brownfield Revitalization Act with respect to the river. The court has put the case on hold pending the outcome of the mediation.

As noted in the Benning Road Site disclosure above, as part of the separation of Exelon and Constellation in February 2022, an assumption agreement was executed transferring any potential future remediation liabilities associated with the Benning Site remediation to a non-utility subsidiary of Exelon. Similarly, any potential future liability associated with the Anacostia River Sediment Project was also assumed by this entity.

Buzzard Point Site (Exelon, PHI, and Pepco). On December 8, 2022, Pepco received a letter from the D.C. OAG, alleging wholly past violations of the District's stormwater discharge and waste disposal requirements related to operations at the Buzzard Point facility, a 9-acre parcel of waterfront property in Washington, D.C. occupied by an active substation and former steam plant building. The letter also alleged wholly past violations by Pepco of stormwater discharge requirements related to its district-wide system of underground vaults. Pepco entered into a Consent Order with the District of Columbia to resolve the alleged violations without any admission of liability. The Consent Order requires Pepco to pay a civil penalty of $10 million. In addition, Pepco has agreed to assess the environmental conditions at its Buzzard Point facility and conduct any remedial actions deemed necessary as a result of the assessment, and also to assess potential environmental impacts associated with the operation of its underground vaults. The Superior Court for the District of Columbia signed and entered the Consent Order, and it became effective on February 2, 2024. Pepco is proceeding through the multi-step environmental investigation and response as outlined in the consent order. Specifically, the DOEE approved Pepco's Preliminary Site Assessment in July 2025. In September 2025, Pepco timely submitted its work plan for the second stage, the Supplemental Investigation Plan, which the DOEE approved in November 2025. Pepco also submitted an environmental assessment to the DOEE of the vault system pursuant to the Consent Order in July 2024. In response to the DOEE's comments, Pepco made revised submissions in May 2025, September 2025, and January 2026. The DOEE approved Pepco's vault system report on February 2, 2026. Exelon, PHI, and Pepco have accrued a liability for the projected costs for the required environmental assessments and remediation. In January 2025, Pepco paid the last installment of the civil penalty. Pepco has concluded that incremental exposure remains reasonably possible, but management cannot reasonably estimate a range of loss beyond the amounts recorded, which are included in the table above.

Litigation and Regulatory Matters

Fund Transfer Restrictions (All Registrants). Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon’s intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

Under applicable law, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at ComEd, PECO, BGE, PHI, Pepco, DPL, or ACE may limit the dividends that these Registrants can distribute to Exelon.

ComEd has agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to restrictions established by the MDPSC that prohibit BGE from paying a dividend on its common shares if (1) after the dividend payment, BGE’s equity ratio would be below 48% as calculated pursuant to the MDPSC’s ratemaking precedents or (2) BGE’s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. No such event has occurred.

Pepco is subject to certain dividend restrictions established by settlements approved by the MDPSC and DCPSC that prohibit Pepco from paying a dividend on its common shares if (1) after the dividend payment, Pepco's equity ratio would be below 48% as calculated pursuant to the MDPSC's and DCPSC's ratemaking precedents, of or (2) Pepco’s senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.

DPL is subject to certain dividend restrictions established by settlements approved by the DEPSC and MDPSC that prohibit DPL from paying a dividend on its common shares if (1) after the dividend payment, DPL's equity ratio would be below 48% as calculated pursuant to the DEPSC's and MDPSC's ratemaking precedents, or (2) DPL’s corporate issuer or senior unsecured credit rating, or its equivalent, is rated by any of the three major credit rating agencies below the generally accepted definition of investment grade. No such event has occurred.

ACE is subject to certain dividend restrictions established by settlements approved by the NJBPU that prohibit ACE from paying a dividend on its common shares if (1) after the dividend payment, ACE's common equity ratio would be below 48% as calculated pursuant to the NJBPU's ratemaking precedents, or (2) ACE's senior corporate issuer or senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. ACE is also subject to a dividend restriction which requires ACE to notify and obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%. No such events have occurred.

DPA and Related Matters (Exelon and ComEd). Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney’s Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. The Companies cooperated fully with the USAO and any government requests or inquiries. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation into its historical state legislative lobbying and related practices in Illinois. The agreement resolved the Department of Justice, investigation into both ComEd and Exelon. which included a payment to the U.S. Treasury of $200 million, which was paid in November 2020. The three-year term of the DPA ended on July 17, 2023, and on that same date the court granted the USAO’s motion to dismiss the pending charge against ComEd that had been deferred by the DPA.

Subsequent to Exelon announcing the receipt of the USAO subpoenas, various lawsuits were filed related to the subject of the subpoenas, and the conduct described in the DPA. Several putative class actions were brought in federal and state court by ComEd customers. These actions were dismissed prior to discovery or trial and those dismissals were affirmed on appeal. A putative class action alleging misrepresentations and omissions in Exelon’s SEC filings related to ComEd’s lobbying activities and the related investigations was also brought in federal court against Exelon and ComEd, which was subsequently settled.

In addition, subsequent to Exelon announcing the receipt of the USAO subpoenas, several shareholders sent letters to the Exelon Board of Directors demanding, among other things, that the Exelon Board of Directors investigate and address alleged breaches of fiduciary duties and other alleged violations by Exelon and ComEd officers and directors related to the conduct described in the DPA. In the first quarter of 2021, the Exelon Board of Directors appointed a Special Litigation Committee (SLC) consisting of disinterested and independent parties to investigate and address these shareholders’ allegations and make recommendations to the Exelon Board of Directors based on the outcome of the SLC’s investigation. In July 2021, one of the demand letter shareholders filed a derivative action against current and former Exelon and ComEd officers and directors, and against Exelon, as nominal defendant, asserting the same claims made in its demand letter. Since that date, multiple parties have filed separate derivative lawsuits that were subsequently consolidated. On October 12, 2021, the parties filed an agreed motion to stay the litigation for 120 days in order to allow the SLC to continue its investigation, which the court granted. The stay was extended several times. Through mediation efforts, a settlement of the derivative claims was reached by the SLC, the Independent Review Committee of the Board (which had been formed in the third quarter of 2022, to ensure the Board’s consideration of any SLC recommendations would be independent and objective), the Board, and certain of the derivative shareholders. On June 16, 2023, the SLC filed a motion for preliminary approval of the settlement, attaching the Stipulation and Agreement of Settlement (Stipulation), which contained the terms of the proposed settlement. The proposed settlement terms include but are not limited to: a payment of $40 million to Exelon by Exelon’s insurers of which $10 million constitutes the attorneys’ fee award to be paid to the Settling Shareholders’ counsel; various compliance and disclosure-related reforms; and certain changes in Board and Committee composition. The non-settling shareholders objected to the settlement and opposed preliminary approval. On September 20, 2024, the court denied without prejudice the SLC’s motion for preliminary approval. The court’s order provided that if the SLC can substantiate or otherwise revise the attorneys’ fees aspect of the settlement, then the SLC could renew its motion for preliminary approval by October 21, 2024. On October 21, 2024, the SLC filed its second renewed motion for preliminary approval, and the Settling Shareholders filed a brief in support of the SLC's second renewed motion for preliminary approval. On November 20, 2024, the non-settling plaintiffs filed an opposition to the renewed motion for preliminary approval. On December 18, 2024, the SLC and Settling Shareholders filed replies in support of the renewed motion for preliminary approval. The court granted the renewed motion for preliminary approval on November 17, 2025, and set the final settlement approval hearing for March 18, 2026.

Maryland Sales and Use Tax Refund Claim (Exelon, BGE, PHI, Pepco, and DPL). Maryland imposes a 6% sales and use tax on the purchase of most goods and services. BGE, Pepco, and DPL have filed or plan to file protective refund claims, totaling an estimated $100 million, treating electric transmission and distribution machinery and equipment as nontaxable pursuant to the manufacturing exemption available under the Maryland sales and use tax law. The Maryland Comptroller has initially denied the refund claim and litigation is pending.

On November 22, 2024, the Appellate Court of Maryland, in a case involving a regulated electric utility operating in Maryland, ruled the purchase of certain transmission and distribution equipment qualify for the sales tax manufacturing exemption. On December 20, 2024, the Maryland Attorney General, on behalf of the Maryland Comptroller, filed a motion for reconsideration with the Appellate Court of Maryland of its ruling. The motion for reconsideration was denied on February 3, 2025.

On February 18, 2025, the Maryland Attorney General, on behalf of the Maryland Comptroller, filed a petition with the Maryland Supreme Court requesting review of the Appellate Court of Maryland's ruling. On April 24, 2025, the Maryland Supreme Court granted the petition to review the ruling. On October 1, 2025, the Maryland Supreme Court heard oral arguments in the case.

In the event transmission and distribution equipment is determined to be exempt, Exelon, BGE, PHI, Pepco, and DPL will record estimated receivables of $100 million, $65 million, $35 million, $25 million, and $10 million, respectively. The sales tax payments were primarily capitalized; therefore, the refund would be recorded as a reduction to PP&E included in rate base.

General (All Registrants). The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The Registrants are also from time to time subject to audits and investigations by the FERC and other regulators. 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. The Registrants 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.

17. Shareholders' Equity (All Registrants)

At-the-Market Program (Exelon)

On August 4, 2022, Exelon executed an equity distribution agreement (“2022 Equity Distribution Agreement”), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program under which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to $1 billion through August 3, 2025. On May 2, 2025, Exelon executed an additional equity distribution agreement ("2025 Equity Distribution Agreement" and, together with the August 4, 2022 Equity Distribution Agreement, "Equity Distribution Agreements"), with certain sales agents and forward sellers and certain forward purchasers, establishing an ATM equity distribution program which it may offer and sell shares of its Common stock, having an aggregate gross sales price of up to $2.5 billion through May 2, 2028. The 2025 Equity Distribution Agreement replaced the 2022 Equity Distribution Agreement. Exelon has no obligation to offer or sell any shares of Common stock under the 2025 Equity Distribution Agreement and may, at any time, suspend or terminate offers and sales under the 2025 Equity Distribution Agreement. Exelon issued the following shares of Common stock in the years ended December 31, 2025, 2024, and 2023:

Effective Period	Shares Issued (in millions)	Weighted-Average Price [(a)]	Net Proceeds [(b)] (in millions)
2025 [(c)]	16.0	$ 43.24	$ 691
2024	4.0	$ 37.60	$ 148
2023	3.6	$ 39.58	$ 140

(a) The 2025 weighted-average price is a net weighted-average price. The 2024 and 2023 weighted-average prices are the gross weighted-average prices as previously disclosed in the 2024 Form 10-K. The 2024 and 2023 weighted-average net prices are $37.04 and $38.99, respectively.
(b) Proceeds were used for general corporate purposes.
(c) In Q4 2025, Exelon settled the entire forward sale agreements with a December 15, 2025 maturity date that had been entered into by various forward sellers under the ATM program as outlined below.

In addition, during the twelve months ended December 31, 2025, Exelon entered into various forward sale agreements under the 2025 ATM programs. The forward sale agreements require Exelon to, at its election prior to the maturity date, either (i) physically settle the transactions by issuing shares of its Common stock to the forward counterparties in exchange for net proceeds at the then-applicable forward sale price specified by the agreements or (ii) net settle the transactions in whole or in part through the delivery to the forward counterparties or receipt from the forward counterparties of cash or shares in accordance with the provisions of the agreements. The following forward sale agreements were entered into under Exelon’s ATM programs in 2025:

Effective Period	Shares Available (in millions)	Weighted-Average Net Price	Maturity Date
Q1 2025	5.7	$ 43.24	December 15, 2025
Q2 2025	6.2	$ 43.51	December 15, 2025
Q2 2025	3.6	$ 43.17	November 16, 2026
Q3 2025	11.5	$ 43.73	December 15, 2026
Q4 2025	0.8	$ 45.42	December 15, 2026

No amounts have been or will be recorded on Exelon's balance sheet with respect to the equity offerings until the equity forward sale agreements have been settled. Each initial forward sale price is subject to adjustment on a daily basis based on a floating interest rate factor and will decrease by other fixed amounts specified in the agreements. Until settlement of the equity forward, earnings per share dilution resulting from the agreement, if any, will be determined under the treasury stock method. For the twelve months ended December 31, 2025, approximately 15.4 million shares under the forward sale agreements were not included in the calculation of diluted earnings per share because their effect would have been antidilutive.

Inclusive of the impact of the forward sale agreements, $1.5 billion of Common stock remained available for sale pursuant to the ATM program as of December 31, 2025.

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

ComEd Common Stock Warrants

The following table presents warrants outstanding to purchase ComEd common stock and shares of common stock reserved for the conversion of warrants. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants.

	December 31,	
	2025	2024
Warrants outstanding	59,960	59,970
Common Stock reserved for conversion	19,987	19,990

Share Repurchases

There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon’s management.

Preferred and Preference Securities

The following table presents Exelon, ComEd, PECO, BGE, Pepco, and ACE's shares of preferred securities authorized, none of which were outstanding, as of December 31, 2025 and 2024. There are no shares of preferred securities authorized for DPL.

	Preferred Securities Authorized
Exelon	100,000,000
ComEd	850,000
PECO	15,000,000
BGE	1,000,000
Pepco	6,000,000
ACE[a]	2,799,979

(a) Includes 799,979 shares of cumulative preferred stock and 2,000,000 of no par value preferred stock as of December 31, 2025 and 2024.

The following table presents ComEd, BGE, and ACE's preference securities authorized, none of which were outstanding as of December 31, 2025 and 2024. There are no shares of preference securities authorized for Exelon, PECO, Pepco, and DPL.

	Preference Securities Authorized
ComEd	6,810,451
BGE[a]	6,500,000
ACE	3,000,000

(a) Includes 4,600,000 shares of unclassified preference securities and 1,900,000 shares of previously redeemed preference securities as of December 31, 2025 and 2024.

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

18. Stock-Based Compensation Plans (All Registrants)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards and restricted stock units. At December 31, 2025, there were approximately 32 million shares authorized for issuance under the LTIP. For the years ended December 31, 2025, 2024, and 2023, exercised and distributed stock-based awards were primarily issued from authorized but unissued Common stock shares.

The Registrants grant cash awards. The following table does not include expense related to these plans as they are not considered stock-based compensation plans under the applicable authoritative guidance.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations and Comprehensive Income. The Utility Registrants' stock-based compensation expense for the years ended December 31, 2025, 2024, and 2023 was not material.

	Year Ended December 31,		
Exelon	**2025**	**2024**	**2023**
Total stock-based compensation expense included in Operating and maintenance expense	$ 41	$ 34	$ 21
Income tax benefit	(10)	(8)	(5)
Total after-tax stock-based compensation expense	$ 31	$ 26	$ 16

Exelon receives a tax deduction based on the intrinsic value of the award on the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The following table presents information regarding Exelon’s realized tax benefit when distributed:

	Year Ended December 31,		
	2025	**2024**	**2023**
Performance share awards	$ 6	$ 9	$ 8
Restricted stock units	3	4	6

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards granted in 2025 and 2024 are settled in common stock at the end of the three-year performance period. The performance share awards granted prior to 2024 are settled 50% in common stock and 50% in cash at the end of the three-year performance period, except for awards that are settled 100% in cash if certain ownership requirements are satisfied.

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

For nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the straight-line method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant for the employee who is retirement eligible prior to December 31 of the grant year or through the date of which the employee reaches retirement eligibility. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

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

The following table summarizes Exelon's nonvested performance share awards activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2024[a]	611,525	$ 39.66
Granted	636,717	42.45
Change in performance	150,204	39.29
Vested	(167,063)	43.09
Forfeited	(139,898)	40.22
Undistributed vested awards[b]	(450,924)	41.71
Nonvested at December 31, 2025[a]	640,561	$ 39.87

(a) Excludes 1,083,128 and 635,526 of performance share awards issued to retirement-eligible employees as of December 31, 2025 and 2024, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2025.

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

	Year Ended December 31,		
	2025[a]	2024	2023
Weighted average grant date fair value (per share)	$ 42.45	$ 35.29	$ 41.82
Total fair value of performance shares vested	25	27	17
Total fair value of performance shares settled in cash	16	27	26

(a) As of December 31, 2025, $8 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.8 years.

Restricted Stock Units

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

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

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

The following table summarizes Exelon’s nonvested restricted stock unit activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2024[a]	293,589	$ 39.29
Granted	338,787	40.47
Vested	(163,374)	40.59
Forfeited	(63,960)	39.05
Undistributed vested awards[b]	(199,280)	40.41
Nonvested at December 31, 2025[a]	205,762	$ 39.19

(a) Excludes 363,156 and 126,732 of restricted stock units issued to retirement-eligible employees as of December 31, 2025 and 2024, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2025.

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

	Year Ended December 31,		
	2025[a]	2024	2023
Weighted average grant date fair value (per share)	$ 40.47	$ 35.54	$ 41.84
Total fair value of restricted stock units vested	15	21	15

(a) As of December 31, 2025, $4 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 1.8 years.

19. Changes in Accumulated Other Comprehensive Income (Loss) (Exelon)

The following table presents changes in Exelon's AOCI, net of tax, by component:

	Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items [a]	Total
Balance at December 31, 2022	$ 2	$ (640)	$ (638)
OCI before reclassifications	(4)	(109)	(113)
Amounts reclassified from AOCI	(1)	26	25
Net current-period OCI	$ (5)	$ (83)	$ (88)
Balance at December 31, 2023	$ (3)	$ (723)	$ (726)
OCI before reclassifications	52	(70)	(18)
Amounts reclassified from AOCI	(4)	28	24
Net current-period OCI	$ 48	$ (42)	$ 6
Balance at December 31, 2024	$ 45	$ (765)	$ (720)
OCI before reclassifications	(7)	(52)	(59)
Amounts reclassified from AOCI	(5)	22	17
Net current-period OCI	$ (12)	$ (30)	$ (42)
Balance at December 31, 2025	$ 33	$ (795)	$ (762)

(a) This AOCI component is included in the computation of net periodic pension and OPEB cost. See Note 12 — Retirement Benefits for additional information. See Exelon's Statements of Operations and Comprehensive Income for individual components of AOCI.

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

The following table presents Income tax benefit (expense) allocated to each component of Exelon's Other comprehensive income (loss):

	For the Years Ended December 31,		
	2025	2024	2023
Pension and non-pension postretirement benefit plans:			
Actuarial losses reclassified to periodic benefit cost	$ (9)	$ (10)	$ (8)
Pension and non-pension postretirement benefit plans valuation adjustments	15	23	33
Unrealized gains on cash flow hedges	2	(15)	2

20. Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

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

	Taxes other than income taxes							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the Year Ended December 31, 2025								
Utility[(a)]	$ 1,003	$ 319	$ 202	$ 112	$ 369	$ 335	$ 30	$ 4
Property	474	45	19	239	170	113	54	2
Payroll	135	37	18	18	29	6	4	3
For the Year Ended December 31, 2024								
Utility[(a)]	$ 925	$ 300	$ 179	$ 105	$ 341	$ 310	$ 27	$ 4
Property	431	32	19	221	159	108	48	3
Payroll	134	37	17	19	28	6	4	3
For the Year Ended December 31, 2023								
Utility[(a)]	$ 875	$ 299	$ 166	$ 97	$ 313	$ 283	$ 26	$ 4
Property	401	33	16	205	147	101	44	2
Payroll	124	31	17	18	27	6	5	3

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(a) The Registrants' utility taxes represents municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Other, net							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the Year Ended December 31, 2025								
AFUDC—Equity	$ 183	$ 66	$ 36	$ 40	$ 41	$ 31	$ 6	$ 4
Non-service net periodic benefit cost	(52)	—	—	—	—	—	—	—
For the Year Ended December 31, 2024								
AFUDC—Equity	$ 157	$ 46	$ 32	$ 25	$ 54	$ 40	$ 12	$ 2
Non-service net periodic benefit cost	(38)	—	—	—	—	—	—	—
For the Year Ended December 31, 2023								
AFUDC—Equity	$ 151	$ 33	$ 31	$ 16	$ 71	$ 54	$ 10	$ 7
Non-service net periodic benefit cost	(18)	—	—	—	—	—	—	—

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

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Cash Flows.

	Depreciation, amortization, and accretion							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the Year Ended December 31, 2025								
Property, plant, and equipment[a]	$ 3,043	$ 1,223	$ 451	$ 503	$ 810	$ 360	$ 226	$ 223
Amortization of regulatory assets[a]	594	337	3	129	125	73	26	25
Amortization of intangible assets, net[a]	3	—	—	—	—	—	—	—
ARO accretion[b]	3	—	—	—	2	2	—	—
Total depreciation, amortization, and accretion	$ 3,643	$ 1,560	$ 454	$ 632	$ 937	$ 435	$ 252	$ 248
For the Year Ended December 31, 2024								
Property, plant, and equipment[a]	$ 2,910	$ 1,167	$ 414	$ 490	$ 782	$ 336	$ 218	$ 211
Amortization of regulatory assets[a]	676	347	14	148	164	70	27	67
Amortization of intangible assets, net[a]	8	—	—	—	—	—	—	—
ARO accretion[b]	2	—	—	—	1	1	—	—
Total depreciation and amortization	$ 3,596	$ 1,514	$ 428	$ 638	$ 947	$ 407	$ 245	$ 278
For the Year Ended December 31, 2023								
Property, plant, and equipment[a]	$ 2,778	$ 1,095	$ 383	$ 509	$ 737	$ 311	$ 208	$ 195
Amortization of regulatory assets[a]	720	308	14	145	253	130	36	88
Amortization of intangible assets, net[a]	8	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 3,506	$ 1,403	$ 397	$ 654	$ 990	$ 441	$ 244	$ 283

(a) Included in Depreciation and amortization expense in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(b) Included in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

	Cash paid (refunded) during the year							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the Year Ended December 31, 2025								
Interest (net of amount capitalized)	$ 2,021	$ 511	$ 242	$ 231	$ 392	$ 205	$ 96	$ 78
Income taxes (net of refunds)	12	224	(186)	(95)	114	88	20	11
For the Year Ended December 31, 2024								
Interest (net of amount capitalized)	$ 1,849	$ 485	$ 218	$ 198	$ 355	$ 183	$ 89	$ 74
Income taxes (net of refunds)	81	250	128	100	150	96	57	20
For the Year Ended December 31, 2023								
Interest (net of amount capitalized)	$ 1,616	$ 441	$ 200	$ 171	$ 301	$ 153	$ 69	$ 68
Income taxes (net of refunds)	10	11	(24)	29	21	6	6	9

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

	Other non-cash operating activities							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the Year Ended December 31, 2025								
Pension and OPEB costs	$ 273	$ 85	$ 7	$ 62	$ 96	$ 35	$ 17	$ 13
Allowance for credit losses	256	55	97	26	78	37	17	24
True-up adjustments to decoupling mechanisms and formula rates[(a)]	746	596	—	87	63	49	16	(2)
Amortization of operating ROU asset	28	—	—	7	16	5	6	2
Change in environmental liabilities	—	—	—	—	1	1	—	—
AFUDC - Equity	(183)	(66)	(36)	(41)	(41)	(31)	(5)	(4)
For the Year Ended December 31, 2024								
Pension and OPEB costs (benefit)	$ 252	$ 72	$ (1)	$ 59	$ 93	$ 32	$ 15	$ 12
Allowance for credit losses	208	23	91	25	69	30	10	28
True-up adjustments to decoupling mechanisms and formula rates[(a)]	109	151	(6)	(52)	16	(15)	10	21
Amortization of operating ROU asset	38	—	—	6	26	6	6	3
Change in environmental liabilities	—	—	—	—	—	—	—	—
AFUDC - Equity	(157)	(46)	(32)	(25)	(54)	(40)	(12)	(2)
For the Year Ended December 31, 2023								
Pension and OPEB costs (benefit)	$ 198	$ 26	$ (14)	$ 56	$ 99	$ 34	$ 18	$ 13
Allowance for credit losses	125	4	45	16	60	33	10	17
True-up adjustments to decoupling mechanisms and formula rates[(a)]	(708)	(556)	7	(84)	(77)	(22)	(21)	(34)
Amortization of operating ROU asset	39	2	—	5	28	6	8	3
Change in environmental liabilities	37	—	—	—	37	37	—	—
AFUDC - Equity	(151)	(33)	(31)	(16)	(71)	(54)	(10)	(7)

(a) For ComEd, reflects the true-up adjustments in Regulatory assets and liabilities associated with its distribution MRP and distribution, energy efficiency, distributed generation, and transmission formula rates. For PECO, reflects the change in Regulatory assets and liabilities associated with its transmission formula rate. For BGE, Pepco, DPL, and ACE, reflects the change in Regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. See Note 2 — Regulatory Matters for additional information.

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

The following tables provide a reconciliation of cash, restricted cash, and cash equivalents reported within the Registrants' Consolidated Balance Sheets that sum to the total of the same amounts in their Consolidated Statements of Cash Flows.

	Cash, restricted cash, and cash equivalents							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2025								
Cash and cash equivalents	$ 626	$ 159	$ 116	$ 217	$ 103	$ 22	$ 9	$ 22
Restricted cash and cash equivalents	525	454	—	3	38	33	3	2
Restricted cash included in Other deferred debits and other assets	50	50	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,201	$ 663	$ 116	$ 220	$ 141	$ 55	$ 12	$ 24
Balance at December 31, 2024								
Cash and cash equivalents	$ 357	$ 105	$ 48	$ 33	$ 139	$ 30	$ 21	$ 14
Restricted cash and cash equivalents	541	486	—	1	24	21	2	—
Restricted cash included in Other deferred debits and other assets	41	41	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 939	$ 632	$ 48	$ 34	$ 163	$ 51	$ 23	$ 14
Balance at December 31, 2023								
Cash and cash equivalents	$ 445	$ 110	$ 42	$ 47	$ 180	$ 48	$ 16	$ 21
Restricted cash and cash equivalents	482	402	9	1	24	24	—	—
Restricted cash included in Other deferred debits and other assets	174	174	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,101	$ 686	$ 51	$ 48	$ 204	$ 72	$ 16	$ 21
Balance at December 31, 2022								
Cash and cash equivalents	$ 407	$ 67	$ 59	$ 43	$ 198	$ 45	$ 31	$ 72
Restricted cash and cash equivalents	566	327	9	24	175	54	121	—
Restricted cash included in Other deferred debits and other assets	117	117	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,090	$ 511	$ 68	$ 67	$ 373	$ 99	$ 152	$ 72

For additional information on restricted cash, see Note 1 — Significant Accounting Policies.

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

Supplemental Balance Sheet Information

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

	Investments					
	Exelon	ComEd	PECO	BGE	PHI	Pepco
Balance at December 31, 2025						
Rabbi trust investments[a]	$ 278	$ —	$ 38	$ 10	$ 157	$ 141
Equity method investments	15	6	7	—	1	—
Other investments	19	—	—	—	—	—
Total investments	$ 312	$ 6	$ 45	$ 10	$ 158	$ 141
Balance at December 31, 2024						
Rabbi trust investments[a]	$ 260	$ —	$ 34	$ 10	$ 151	$ 135
Equity method investments	15	6	7	—	1	—
Other investments	15	—	—	—	—	—
Total investments	$ 290	$ 6	$ 41	$ 10	$ 152	$ 135

(a) The Registrants' debt and equity security investments and life insurance contracts are recorded at fair market value.

	Accrued expenses							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2025								
Compensation-related accruals[a]	$ 705	$ 209	$ 96	$ 99	$ 125	$ 35	$ 24	$ 17
Taxes accrued	242	94	306	191	107	69	25	18
Interest accrued	538	155	75	55	92	49	18	20
Balance at December 31, 2024								
Compensation-related accruals[a]	$ 679	$ 197	$ 87	$ 88	$ 132	$ 38	$ 26	$ 18
Taxes accrued	217	96	13	34	110	92	11	11
Interest accrued	468	150	60	50	83	44	16	18

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

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

21. Related Party Transactions (All Registrants)

Service Company Costs for Corporate Support

The Registrants receive a variety of corporate support services from BSC. Pepco, DPL, and ACE also receive corporate support services from PHISCO. See Note 1 — Significant Accounting Policies for additional information regarding BSC and PHISCO.

The following table presents the service company costs allocated to the Registrants:

	Operating and maintenance from affiliates			Capitalized costs from affiliates		
	For the years ended December 31,			For the years ended December 31,		
	2025	2024	2023	2025	2024	2023
Exelon						
BSC				$ 683	$ 633	$ 670
PHISCO				109	114	96
ComEd						
BSC	$ 404	$ 418	$ 353	279	254	307
PECO						
BSC	246	243	213	105	112	120
BGE						
BSC	251	246	221	123	110	90
PHI						
BSC	200	200	177	176	157	153
PHISCO	—	—	—	109	114	95
Pepco						
BSC	126	125	114	76	70	59
PHISCO	119	125	122	47	50	39
DPL						
BSC	80	78	73	52	49	43
PHISCO	98	103	98	33	34	29
ACE						
BSC	64	64	59	40	32	47
PHISCO	91	97	92	29	30	26

Current Receivables from/Payables to Affiliates

The following tables present current Receivables from affiliates and current Payables to affiliates:

December 31, 2025

	Receivables from affiliates:									
Payables to affiliates:	ComEd	PECO	BGE	Pepco	DPL	ACE	BSC	PHISCO	Other	Total
ComEd		$ —	$ —	$ —	$ —	$ —	$ 76	$ —	$ 5	$ 81
PECO	$ —		—	—	—	—	33	—	2	35
BGE	—	—		—	—	—	39	—	—	39
PHI	—	—	—	—	—	—	5	2	11	18
Pepco	—	—	—		—	—	25	11	1	37
DPL	—	—	—	—		—	15	10	—	25
ACE	—	—	—	—	—		14	10	—	24
Other	5	—	1	—	2	12	—	—		20
Total	$ 5	$ —	$ 1	$ —	$ 2	$ 12	$ 207	$ 33	$ 19	$ 279

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

December 31, 2024

	Receivables from affiliates:									
Payables to affiliates:	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
ComEd		$ —	$ —	$ —	$ —	$ —	$ 67	$ —	$ 10	$ 77
PECO	$ —		—	—	—	—	37	—	4	41
BGE	—	—		—	—	—	47	—	1	48
PHI	—	—	—	—	—	—	7	1	10	18
Pepco	—	—	—		—	—	21	15	1	37
DPL	—	—	—	—		—	14	11	1	26
ACE	—	—	—	—	—		11	10	1	22
Other	4	—	—	1	—	7	—	—		12
Total	$ 4	$ —	$ —	$ 1	$ —	$ 7	$ 204	$ 37	$ 28	$ 281

Borrowings from Exelon/PHI Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing both Exelon and PHI operate an intercompany money pool. PECO and PHI Corporate participate in the Exelon money pool. Pepco, DPL, and ACE participate in the PHI intercompany money pool.

Long-term Debt to Financing Trusts

The following table presents Long-term debt to financing trusts:

	At December 31,					
	2025			2024		
	Exelon	**ComEd**	**PECO**	**Exelon**	**ComEd**	**PECO**
ComEd Financing III	$ 206	$ 206	$ —	$ 206	$ 206	$ —
PECO Trust III	81	—	81	81	—	81
PECO Trust IV	103	—	103	103	—	103
Total	$ 390	$ 206	$ 184	$ 390	$ 206	$ 184

Charitable Contributions

In December 2025, Exelon Corporation made an unconditional promise to give $30 million to the Exelon Foundation. The contribution was recorded in Operating and maintenance expense within the Consolidated Statements of Operations and Comprehensive Income with the offset in Other current liabilities on the Consolidated Balance Sheets.

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

All Registrants

None.

ITEM 9A. CONTROLS AND PROCEDURES

All Registrants—Disclosure Controls and Procedures

During the fourth quarter of 2025, each of the Registrant's management, including its principal executive officer and principal financial officer, evaluated disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report, pursuant to Exchange Act Rules 13a-15(b) and 15d-15(b). These disclosure controls and procedures have been designed by the Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to that Registrant’s management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated, and reported, as applicable, within the time periods specified in the SEC’s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2025, the principal executive officer and principal financial officer of each of the Registrants concluded that such Registrant’s disclosure controls and procedures were effective. (Item 307 of Regulation S-K).

All Registrants—Changes in Internal Control Over Financial Reporting

Each Registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there were no changes in internal control over financial reporting (as defined in Exchange Act Rules 13a-15(d) and 15d-15(d)) that occurred during the fourth quarter of 2025 that have materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting.

All Registrants—Internal Control Over Financial Reporting

Management is required to assess and report on the effectiveness of its internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f)) as of December 31, 2025. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2025 and therefore concluded that each Registrant’s internal control over financial reporting was effective. Management’s Report on Internal Control Over Financial Reporting is included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

ITEM 9B. OTHER INFORMATION

All Registrants

None of our officers or directors, as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934, adopted, modified, or terminated a “Rule 10b5-1 trading arrangement” or a “non-Rule 10b5-1 trading arrangement,” as defined in Item 408 of Regulation S-K, during the three months ended December 31, 2025.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable

PART III

PECO, BGE, PHI, Pepco, DPL, and ACE meet the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K for a reduced disclosure format. Accordingly, all items in this section relating to PECO, BGE, PHI, Pepco, DPL, and ACE are not presented.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants as of February 12, 2026.

Directors, Director Nomination Process and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), compliance with Section 16(a) of the Exchange Act (Item 405 of Regulation S-K), the director nomination process (Item 407(c)(3)), and the audit committee (Item 407(d)(4) and (d)(5)) is incorporated herein by reference to information to be contained in Exelon's Proxy Statement for the 2026 Annual Meeting of Shareholders (2026 Exelon Proxy Statement) and the ComEd information statement (2026 ComEd Information Statement) to be filed with the SEC on or before April 30, 2026 pursuant to Regulation 14A or 14C, as applicable, under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to all directors, officers, and employees of the Registrants and their subsidiaries. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at www.exeloncorp.com. The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Exelon's Corporate Secretary, 10 South Dearborn Street, P.O. Box 805398, Chicago, Illinois 60680-5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, www.exeloncorp.com, or in a report on Form 8-K.

Insider Trading Policy

Exelon has adopted insider trading policies and procedures governing transactions in securities of the Registrants and their subsidiaries by directors, officers, and employees, or the Registrants themselves, that are reasonably designed to promote compliance with insider trading laws, rules and regulations, and any listing standards applicable to the Registrants. A copy of the Exelon Insider Trading Policy is filed as Exhibit 19.1 to this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the sections captioned "Compensation Discussion and Analysis" and "Talent Management and Compensation Committee Report" in the 2026 Exelon Proxy Statement or the section captioned "Executive Compensation" in the 2026 ComEd Information Statement, which are incorporated herein by reference.

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

The additional information required by this item will be set forth under Ownership of Exelon Stock in the 2026 Exelon Proxy Statement or the 2026 ComEd Information Statement, which are incorporated herein by reference.

No ComEd securities are authorized for issuance under equity compensation plans.

Securities Authorized for Issuance under Exelon Equity Compensation Plans

Plan Category	[A] Number of securities to be issued upon exercise of outstanding Options, warrants and rights (Note 1)	[B] Weighted-average price of outstanding Options, warrants and rights (Note 2)	[C] Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column [A]) (Note 3)
Equity compensation plans approved by security holders	3,786,845	$ —	37,917,762

(1) The equity compensation plans approved by the Company's shareholders are the Exelon Corporation 2020 Long-Term Incentive Plan and the Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective September 25, 2019. See Note 18 — Stock-Based Compensation Plans of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.
The number in column (A) includes: (i) 586,598 unvested restricted stock units and 2,906,398 unvested performance shares that were granted under the Exelon LTIP or predecessor company plans (including shares awarded under those plans and deferred into the stock deferral plan), both including accrued and reinvested dividends, and (ii) 293,849 deferred stock units granted to directors as part of their compensation.
For reporting purposes, the number of unvested performance shares includes: (i) the 2023-2025 performance share awards at maximum payout, assuming half of the shares are settled in cash and half in Exelon stock; and (ii) the 2024-2026 and 2025-2027 performance share awards at maximum payout, assuming settlement all in Exelon stock, pursuant to the terms of the long-term incentive program. Performance share awards may be paid between 0% and 200% of target, depending on the achievement of performance goals established for such awards.

(2) There are no outstanding stock options. The weighted-average price reported in column B does not take the performance shares and shares credited to deferred compensation plans into account.

(3) Includes 9,200,672 shares remaining available for issuance from the employee stock purchase plan.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The additional information required by this item will be set forth under the sections captioned "Related Person Transactions" and "Director Independence" in the 2026 Exelon Proxy Statement or the sections captioned "Related Person Transactions," "Independence Standards," and "Director Nominees" in the 2026 ComEd Information Statement, which are incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under the section captioned "Ratification of PricewaterhouseCoopers LLP as Exelon’s Independent Auditor for 2026" in the 2026 Exelon Proxy Statement and the section captioned "Audit Matters" in the 2026 ComEd Information Statement, which are incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

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

(1) Exelon

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Balance Sheets at December 31, 2025 and 2024

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2025, 2024, and 2023

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedules:

Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2025 and 2024 and for the Years Ended December 31, 2025, 2024, and 2023

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Operations and Other Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Operating expenses			
Operating and maintenance	$ 92	$ 7	$ 88
Operating and maintenance from affiliates	8	8	7
Other	1	1	1
Total operating expenses	101	16	96
Operating loss	(101)	(16)	(96)
Other income and (deductions)			
Interest expense, net	(684)	(593)	(544)
Equity in earnings of investments	3,335	2,887	2,728
Interest income from affiliates, net	11	15	9
Other, net	28	22	19
Total other income and (deductions)	2,690	2,331	2,212
Income from before income taxes	2,589	2,315	2,116
Income taxes	(179)	(145)	(212)
Net income	$ 2,768	$ 2,460	$ 2,328
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Actuarial losses reclassified to periodic benefit cost	22	28	26
Pension and non-pension postretirement benefit plans valuation adjustments	(52)	(70)	(109)
Unrealized (loss) gain on cash flow hedges	(12)	48	(5)
Other comprehensive (loss) income	(42)	6	(88)
Comprehensive income	$ 2,726	$ 2,466	$ 2,240

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Net cash flows provided by operating activities	$ 1,775	$ 2,022	$ 1,486
Cash flows from investing activities			
Changes in Exelon intercompany money pool	(33)	8	(43)
Investment in affiliates	(2,055)	(1,568)	(1,864)
Other investing activities	(1)	(2)	(1)
Net cash flows used in investing activities	(2,089)	(1,562)	(1,908)
Cash flows from financing activities			
Changes in short-term borrowings	(427)	(99)	78
Proceeds from short-term borrowings with maturities greater than 90 days	—	150	—
Repayments on short-term borrowings with maturities greater than 90 days	(500)	(150)	—
Issuance of long-term debt	3,000	1,700	2,500
Retirement of long-term debt	(810)	(715)	(850)
Issuance of common stock	691	148	140
Dividends paid on common stock	(1,615)	(1,523)	(1,433)
Proceeds from employee stock plans	35	43	41
Other financing activities	(40)	(36)	(39)
Net cash flows provided by (used in) financing activities	334	(482)	437
Increase (decrease) in cash, restricted cash, and cash equivalents	20	(22)	15
Cash, restricted cash, and cash equivalents at beginning of period	4	26	11
Cash, restricted cash, and cash equivalents at end of period	$ 24	$ 4	$ 26

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

	December 31,	
(In millions)	2025	2024
ASSETS		
Current assets		
Cash and cash equivalents	$ 24	$ 4
Accounts receivable, net		
Other accounts receivable	622	288
Accounts receivable from affiliates	10	19
Notes receivable from affiliates	250	217
Regulatory assets	165	186
Other	7	19
Total current assets	1,078	733
Property, plant, and equipment, net	45	45
Deferred debits and other assets		
Regulatory assets	2,925	2,851
Investments in affiliates	43,670	40,741
Deferred income taxes	546	747
Non-pension postretirement benefit asset	128	186
Other	136	149
Total deferred debits and other assets	47,405	44,674
Total assets	$ 48,528	$ 45,452

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

	December 31,	
(In millions)	2025	2024
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 927
Long-term debt due within one year	750	807
Accounts payable	177	142
Accrued expenses	188	155
Payables to affiliates	361	360
Regulatory liabilities	8	11
Pension obligations	36	40
Other	46	3
Total current liabilities	1,566	2,445
Long-term debt	13,547	11,334
Deferred credits and other liabilities		
Regulatory liabilities	89	94
Pension obligations	4,398	4,346
Deferred income taxes	53	50
Other	77	262
Total deferred credits and other liabilities	4,617	4,752
Total liabilities	19,730	18,531
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 1,023 shares and 1,005 shares outstanding as of December 31, 2025 and 2024, respectively)	22,106	21,338
Treasury stock, at cost (2 shares as of December 31, 2025 and 2024)	(123)	(123)
Retained earnings	7,577	6,426
Accumulated other comprehensive loss, net	(762)	(720)
Total shareholders' equity	28,798	26,921
Total liabilities and shareholders' equity	$ 48,528	$ 45,452

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12-04, Schedule I of Regulation S-X. These statements should be read in conjunction with the consolidated financial statements, and notes thereto, of Exelon Corporation.

As of December 31, 2025, 2024, and 2023, Exelon Corporate owned 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%.

2. Regulatory Matters and Retirement Benefits

See Note 2—Regulatory Matters and Note 12—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's regulatory assets and retirement benefits.

3. Derivative Financial Instruments

See Note 13—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's derivatives.

4. Debt and Credit Agreements

Short-Term Borrowings

Exelon Corporate meets its short-term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had no outstanding commercial paper borrowings as of December 31, 2025 and $426 million outstanding commercial paper as of December 31, 2024.

Revolving Credit Agreements

On August 29, 2024, Exelon Corporate entered into a revolving credit facility with an aggregate bank commitment of $900 million at a variable interest rate of SOFR plus 1.075%, which replaced its existing $900 million syndicated revolving credit facility, and extended the maturity date to August 29, 2029.

As of December 31, 2025, Exelon Corporate had a $900 million aggregate bank commitment under its existing syndicated revolving facility in which $897 million was available to support additional commercial paper as of December 31, 2025. Exelon Corporate had $3 million outstanding letters of credit as of December 31, 2025. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon Corporate's credit agreement.

Exelon Corporate had no outstanding amounts on the revolving credit facilities as of December 31, 2025.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million. The loan agreement was renewed in the first quarter of 2024 and was bifurcated into two tranches of $350 million and $150 million on March 14, 2024. The loan agreements were renewed in the first quarter of 2025, extending the expiration date to March 13, 2026 with a variable interest rate equal to SOFR plus 1.00%. Exelon Corporate repaid the term loan on December 5, 2025.

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

Convertible Senior Notes

On December 4, 2025, Exelon Corporation issued $1 billion aggregate principal amount of 3.25% Convertible Senior Notes due 2029. The Convertible Senior Notes bear interest at 3.25% per year, payable semiannually, and mature on March 15, 2029. The Convertible Notes are convertible into cash or a combination of cash and shares of common stock at Exelon's discretion, with an initial conversion price of approximately $57.11 per share. See Note 14 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Convertible Senior Notes.

Debt Extinguishment

During the twelve months ended December 31, 2024, Exelon Corporate repurchased a portion of its Senior unsecured notes with a principal balance of $244 million outstanding in exchange for cash of $215 million. The repurchase was accounted for as a debt extinguishment and resulted in a pre-tax gain of $28 million, which is reflected on Exelon Corporate's Condensed Statement of Operations and Comprehensive income within Interest expense, net.

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate at December 31, 2025 and December 31, 2024:

	Rates		Maturity Date	December 31, 2025	December 31, 2024
Long-term debt					
Senior unsecured notes	2.75 % -	7.60 %	2026 - 2055	$ 13,288	$ 12,095
Junior subordinated notes		6.50 %	2055	1,000	—
Total long-term debt				14,288	12,095
Unamortized debt discount and premium, net				(24)	(24)
Unamortized debt issuance costs				(96)	(71)
Fair value adjustment				129	141
Long-term debt due within one year[(a)]				(750)	(807)
Long-term debt				$ 13,547	$ 11,334

The long-term debt maturities for Exelon Corporate for the periods 2026 through 2030 and thereafter are as follows:

2026	$ 750
2027	650
2028	1,000
2029	1,650
2030	1,250
Thereafter	8,988
Total long-term debt	$ 14,288

5. Commitments and Contingencies

See Note 16—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate’s commitments and contingencies.

6. Related Party Transactions

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
(In millions)	2025	2024	2023
Operating and maintenance from affiliates:			
BSC[a]	$ 8	$ 8	$ 7
Total operating and maintenance from affiliates:	$ 8	$ 8	$ 7
Interest income (expense) from affiliates, net:			
BSC	$ 8	$ 11	$ 6
EEDC[b]	3	4	3
Total interest income from affiliates, net:	$ 11	$ 15	$ 9
Equity in earnings (losses) of investments:			
EEDC[b]	$ 3,339	$ 2,886	$ 2,727
PCI	3	3	2
Connectiv, LLC	(1)	(2)	—
Exelon Enterprises	1	—	1
Exelon InQB8R	—	—	(2)
Exelon Transmission Company	(6)	—	—
Other	(1)	—	—
Total equity in earnings of investments:	$ 3,335	$ 2,887	$ 2,728
Cash contributions received from affiliates	$ 2,464	$ 2,250	$ 1,978

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

(in millions)	At December 31, 2025	2024
Accounts receivable from affiliates (current):		
BSC	$ 2	$ 2
ComEd	1	5
PECO	—	3
BGE	—	2
PHISCO	7	7
Total accounts receivable from affiliates (current):	$ 10	$ 19
Notes receivable from affiliates (current):		
BSC[a]	$ 170	$ 154
PHI	80	63
Total notes receivable from affiliates (current):	$ 250	$ 217
Investments in affiliates:		
BSC[a]	$ 384	$ 384
EEDC[b]	42,847	39,905
PCI	60	57
UII	360	365
Voluntary Employee Beneficiary Association trust	5	—
Exelon Enterprises	5	4
Conectiv	13	14
Exelon InQB8R	—	13
Other	(4)	(1)
Total investments in affiliates:	$ 43,670	$ 40,741
Accounts payable to affiliates (current):		
UII	$ 361	$ 360
BSC[a]	—	—
Total accounts payable to affiliates (current):	$ 361	$ 360

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology, and supply management services. All services are provided at cost, including applicable overhead.
(b) EEDC consists of ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE.

Charitable Contributions

In December 2025, Exelon Corporation made an unconditional promise to give $30 million to the Exelon Foundation. The contribution was recorded in Operating and maintenance expense within the Condensed Statements of Operations and Comprehensive Income with the offset in Other current liabilities on the Condensed Balance Sheets.

Exelon Corporation and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses[a]	$ 513	$ 290 [b]	$ 23	$ 297 [c]	$ 529
Deferred tax valuation allowance	120	—	20	—	140
For the year ended December 31, 2024					
Allowance for credit losses[a]	$ 399	$ 271 [b]	$ 22	$ 179 [c]	$ 513
Deferred tax valuation allowance	114	—	6	—	120
For the year ended December 31, 2023					
Allowance for credit losses[a]	$ 409	$ 171 [b]	$ 20	$ 201 [c]	$ 399
Deferred tax valuation allowance	94	—	20	—	114

(a) Excludes the noncurrent Allowance for credit losses related to PECO's installment plan receivables of $13 million, $13 million, and $6 million for the years ended December 31, 2025, 2024, and 2023, respectively.
(b) The amount charged to costs and expenses includes the amount reclassified to Regulatory assets/liabilities under different mechanisms applicable to the different jurisdictions in which the Utility Registrants operate.
(c) Primarily reflects write-offs, net of recoveries, of individual accounts receivable.

Commonwealth Edison Company and Subsidiary Companies

(2) ComEd

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024, and 2023
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024, and 2023
	Consolidated Balance Sheets at December 31, 2025 and 2024
	Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2025, 2024, and 2023
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023
	Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Commonwealth Edison Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses	$ 143	$ 80 [(a)]	$ 20	$ 105 [(b)]	$ 138
For the year ended December 31, 2024					
Allowance for credit losses	$ 86	$ 71 [(a)]	$ 28	$ 42 [(b)]	$ 143
For the year ended December 31, 2023					
Allowance for credit losses	$ 76	$ 45 [(a)]	$ 13	$ 48 [(b)]	$ 86

(a) ComEd is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through a rider mechanism. The amount charged to costs and expenses includes the amount that was reclassified to Regulatory assets/liabilities under such mechanism. See Note 2 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Write-offs, net of recoveries of individual accounts receivable.

PECO Energy Company and Subsidiary Companies

(3) PECO

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Balance Sheets at December 31, 2025 and 2024

Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2025, 2024, and 2023

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses[a]	$ 151	$ 98	$ 7	$ 101 [c]	$ 155
Deferred tax valuation allowance	6	—	—	—	6
For the year ended December 31, 2024					
Allowance for credit losses[a]	$ 103	$ 88	$ (1)	$ 39 [c]	$ 151
Deferred tax valuation allowance	7	—	(1)	—	6
For the year ended December 31, 2023					
Allowance for credit losses[a]	$ 114	$ 43 [b]	$ 9	$ 63 [c]	$ 103
Deferred tax valuation allowance	7	—	—	—	7

(a) Excludes the noncurrent Allowance for credit losses related to PECO's installment plan receivables of $13 million, $13 million, and $6 million for the years ended December 31, 2025, 2024, and 2023, respectively.
(b) The amount charged to costs and expenses includes the amount that was reclassified to the COVID-19 regulatory asset. See Note 2 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Write-offs, net of recoveries of individual accounts receivable.

Baltimore Gas and Electric Company

(4) BGE

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024 and 2023

Statements of Cash Flows for the Years Ended December 31, 2025, 2024 and 2023

Balance Sheets at December 31, 2025 and 2024

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2025, 2024 and 2023

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Baltimore Gas and Electric Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses	$ 62	$ 44 (a)	$ (3)	$ 31 (b)	$ 72
Deferred tax valuation allowance	3	—	—	—	3
For the year ended December 31, 2024					
Allowance for credit losses	$ 53	$ 39 (a)	$ 4	$ 34 (b)	$ 62
Deferred tax valuation allowance	3	—	—	—	3
For the year ended December 31, 2023					
Allowance for credit losses	$ 64	$ 26 (a)	$ 5	$ 42 (b)	$ 53
Deferred tax valuation allowance	3	—	—	—	3

(a) The amount charged to costs and expenses includes the amount that was reclassified to Regulatory assets/liabilities under different mechanisms as approved by the MDPSC.
(b) Write-offs, net of recoveries of individual accounts receivable.

Pepco Holdings LLC and Subsidiary Companies

(5) PHI

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Balance Sheets at December 31, 2025 and 2024

Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2025, 2024, and 2023

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Pepco Holdings LLC and Subsidiary Companies

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses	$ 157	$ 68 [a]	$ (1)	$ 60 [b]	$ 164
Deferred tax valuation allowance	32	—	—	—	32
For the year ended December 31, 2024					
Allowance for credit losses	$ 157	$ 73 [a]	$ (9)	$ 64 [b]	$ 157
Deferred tax valuation allowance	35	—	(3)	—	32
For the year ended December 31, 2023					
Allowance for credit losses	$ 155	$ 57 [a]	$ (7)	$ 48 [b]	$ 157
Deferred tax valuation allowance	35	—	—	—	35

(a) The amount charged to costs and expenses includes the amount that was reclassified to Regulatory assets/liabilities under different mechanisms applicable to the different jurisdictions Pepco, DPL, and ACE operate in.

(b) Write-offs, net of recoveries of individual accounts receivable.

Potomac Electric Power Company

(6) Pepco

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024 and 2023

Statements of Cash Flows for the Years Ended December 31, 2025, 2024 and 2023

Balance Sheets at December 31, 2025 and 2024

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2025, 2024 and 2023

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Potomac Electric Power Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses	$ 86	$ 42 [(a)]	$ (2)	$ 31 [(b)]	$ 95
For the year ended December 31, 2024					
Allowance for credit losses	$ 80	$ 48 [(a)]	$ (10)	$ 32 [(b)]	$ 86
For the year ended December 31, 2023					
Allowance for credit losses	$ 72	$ 31 [(a)]	$ (5)	$ 18 [(b)]	$ 80

(a) The amount charged to costs and expenses includes the amount that was reclassified to Regulatory assets/liabilities under different mechanisms as approved by the DCPSC and MDPSC.
(b) Write-offs, net of recoveries of individual accounts receivable.

Delmarva Power & Light Company

(7) DPL

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024 and 2023

Statements of Cash Flows for the Years Ended December 31, 2025, 2024 and 2023

Balance Sheets at December 31, 2025 and 2024

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2025, 2024 and 2023

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Delmarva Power & Light Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses	$ 26	$ 17 (a)	$ —	$ 14 (b)	$ 29
Deferred tax valuation allowance	29	—	—	—	29
For the year ended December 31, 2024					
Allowance for credit losses	$ 27	$ 11 (a)	$ —	$ 12 (b)	$ 26
Deferred tax valuation allowance	32	—	(3)	—	29
For the year ended December 31, 2023					
Allowance for credit losses	$ 28	$ 10 (a)	$ —	$ 11 (b)	$ 27
Deferred tax valuation allowance	32	—	—	—	32

(a) The amount charged to costs and expenses includes the amount that was reclassified to Regulatory assets/liabilities under different mechanisms as approved by the DEPSC and MDPSC.
(b) Write-offs, net of recoveries of individual accounts receivable.

Atlantic City Electric Company and Subsidiary Company

(8) ACE

(i) Financial Statements (Item 8):

Report of Independent Registered Public Accounting Firm dated February 12, 2026 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Statements of Cash Flows for the Years Ended December 31, 2025, 2024, and 2023

Consolidated Balance Sheets at December 31, 2025 and 2024

Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2025, 2024, and 2023

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2025, 2024, and 2023

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Atlantic City Electric Company and Subsidiary Company

Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
(In millions)					
For the year ended December 31, 2025					
Allowance for credit losses	$ 45	$ 9 (a)	$ 1	$ 15 (b)	$ 40
For the year ended December 31, 2024					
Allowance for credit losses	$ 50	$ 14 (a)	1	$ 20 (b)	$ 45
For the year ended December 31, 2023					
Allowance for credit losses	$ 55	$ 16 (a)	$ (2)	$ 19 (b)	$ 50

(a) ACE is allowed to recover from or refund to customers the difference between its annual credit loss expense and the amounts collected in rates annually through the Societal Benefits Charge. The amount charged to costs and expenses includes the amount that was reclassified to Regulatory assets/liabilities under such mechanism. See Note 2 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Write-offs, net of recoveries of individual accounts receivable.

Exhibits required by Item 601 of Regulation S-K:

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

(2) Plans of acquisition, reorganization, arrangement, liquidation, or succession

Exhibit No.	Description	Location
2-1	Separation Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation	File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 2.1

(3) Articles of Incorporation and Bylaws

Exelon Corporation

Exhibit No.	Description	Location
3-1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended April 30, 2024	File No. 001-16169, Form 10-Q dated August 1, 2024, Exhibit 3.1
3-2	Amended and Restated Bylaws of Exelon Corporation, as amended on April 30, 2024	File No. 001-16169, Form 10-Q dated August 1, 2024, Exhibit 3.2

Baltimore Gas and Electric Company

Exhibit No.	Description	Location
3-3	Articles of Restatement to the Charter of Baltimore Gas and Electric Company, restated as of August 16, 1996	File No. 001-01910, Form 10-Q dated November 14, 1996, Exhibit 3
3-4	Articles of Amendment to the Charter of Baltimore Gas and Electric Company as of February 2, 2010	File No. 001-01910, Form 8-K dated February 4, 2010, Exhibit 3.1
3-5	Amended and Restated Bylaws of Baltimore Gas and Electric Company dated August 3, 2020	File No. 001-01910, Form 10-Q dated August 4, 2020, Exhibit 3.4

Commonwealth Edison Company

Exhibit No.	Description	Location
3-6	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock”	File No. 001-01839, Form 10-K dated March 30, 1995, Exhibit 3.2
3-7	Amended and Restated Bylaws of Commonwealth Edison Company, Effective February 22, 2021	File No. 001-01839, Form 10-K dated February 24, 2021, Exhibit 3.6

PECO Energy Company

Exhibit No.	Description	Location
3-8	Amended and Restated Articles of Incorporation of PECO Energy Company	File No. 001-01401, Form 10-K dated April 2, 2001, Exhibit 3.3
3-9	Amended and Restated Bylaws of PECO Energy Company dated August 3, 2020	File No. 000-16844, Form 10-Q dated August 4, 2020, Exhibit 3.3

Pepco Holdings LLC

Exhibit No.	Description	Location
3-10	Certificate of Formation of Pepco Holdings LLC, dated March 23, 2016	File No. 001-31403, Form 8-K dated March 24, 2016, Exhibit 3.2
3-11	Amended and Restated Limited Liability Company Agreement of Pepco Holdings LLC, dated August 3, 2020	File No. 001-31403, Form 10-Q dated August 4, 2020, Exhibit 3.5

Atlantic City Electric Company

Exhibit No.	Description	Location
3-12	Restated Certificate of Incorporation of Atlantic City Electric Company (filed in New Jersey on August 9, 2002)	File No. 001-03559, Amendment No. 1 to Form U5B dated February 13, 2003, Exhibit B.8.1
3-13	Bylaws of Atlantic City Electric Company	File No. 001-03559, Form 10-Q dated May 9, 2005, Exhibit 3.2.2

Delmarva Power & Light Company

Exhibit No.	Description	Location
3-14	Restated Certificate and Articles of Incorporation of Delmarva Power & Light Company (as filed in Delaware and Virginia)	File No. 001-01405, Form 10-K dated March 1, 2007, Exhibit 3.3
3-15	Bylaws of Delmarva Power & Light Company	File No. 001-01405, Form 10-Q dated May 9, 2005, Exhibit 3.2.1

Potomac Electric Power Company

Exhibit No.	Description	Location
3-16	Restated Articles of Incorporation of Potomac Electric Power Company (as filed in the District of Columbia)	File No. 001-31403, Form 10-Q dated May 5, 2006, Exhibit 3.1
3-17	Restated Articles of Incorporation and Articles of Restatement of Potomac Electric Power Company (as filed in Virginia)	File No. 001-01072, Form 10-Q dated November 4, 2011, Exhibit 3.3
3-18	Bylaws of Potomac Electric Power Company	File No. 001-01072, Form 10-Q dated May 5, 2006, Exhibit 3.2

(4) Instruments Defining the Rights of Securities Holders, Including Indentures

Exelon Corporation

Exhibit No.	Description	Location
4-1	Exelon Corporation Direct Stock Purchase Plan	File No. 333-222989, Prospectus 424(b)(2) dated June 20, 2025
4-2	Indenture dated May 1, 2001 between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 10-Q dated July 26, 2005, Exhibit 4.10
4-3	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation	File No. 001-16169, Form 8-K dated June 9, 2005, Exhibit 99.3
4-4	Indenture, dated as of June 17, 2014, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee	File No. 001-16169, Form 8-K dated June 23, 2014, Exhibit 4.1
4-4-1	Third Supplemental Indenture, dated as of February 1, 2025, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee	File No. 001-16169, Form 8-K dated February 19, 2025, Exhibit 4.2
4-5	Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated June 11, 2015, Exhibit 4.1
4-5-1	First Supplemental Indenture, dated as of June 11, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated June 11, 2015, Exhibit 4.2
4-5-2	Second Supplemental Indenture, dated as of December 2, 2015, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated December 2, 2015, Exhibit 4.1
4-5-3	Third Supplemental Indenture, dated as of April 7, 2016, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated April 7, 2016, Exhibit 4.2

Exhibit No.	Description	Location
4-5-4	Fourth Supplemental Indenture, dated as of April 1, 2020, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated April 1, 2020, Exhibit 4.2
4-5-5	Fifth Supplemental Indenture, dated as of March 7, 2022, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated March 7, 2022, Exhibit 4.2
4-5-6	Sixth Supplemental Indenture, dated as of February 1, 2023, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated February 21, 2023, Exhibit 4.2
4-5-7	Seventh Supplemental Indenture, dated as of February 27, 2024, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated February 27, 2024, Exhibit 4.2
4-5-8	Eighth Supplemental Indenture, dated as of February 1, 2025, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated February 21, 2025, Exhibit 4.2
4-6	Indenture, dated as of December 4, 2025, between Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee	File No. 001-16169, Form 8-K dated December 4, 2025, Exhibit 4.1
4-7	Equity Distribution Agreement, dated May 2, 2025, by and among the Company, Barclays Capital Inc., BNP Paribas Securities Corp., BofA Securities, Inc., Citigroup Global Markets Inc., Credit Agricole Securities (USA) Inc.,	File No. 001-16169, Form 8-K dated May 2, 2025, Exhibit 1.1
4-8	Description of Exelon Securities	Filed herewith.

Baltimore Gas and Electric Company

Exhibit No.	Description	Location
4-7	Indenture dated as of July 24, 2006 between Baltimore Gas and Electric Company and Deutsche Bank Trust Company Americas, as trustee	File No. 333-135991, Registration Statement on Form S-3 dated July 24, 2006, Exhibit 4(b)
4-8	Form of 2.400% notes due 2026 issued August 18, 2016 by Baltimore Gas and Electric Company	File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.1
4-9	Form of 3.500% Note due 2046 issued August 18, 2016 by Baltimore Gas and Electric Company	File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.2
4-10	Form of 3.750% Note due 2047 issued August 24, 2017 by Baltimore Gas and Electric Company	File No. 001-01910, Form 8-K dated August 24, 2017, Exhibit 4.1
4-11	Form of 4.550% Note due 2052 issued June 6, 2022 by Baltimore Gas and Electric Company	File No. 001-01910, Form 8-K dated June 6, 2022, Exhibit 4.2
4-12	Form of 5.400% Note due 2053 issued May 10, 2023 by Baltimore Gas and Electric	File No. 001-01910, Form 8-K dated May 10, 2023, Exhibit 4.2
4-13	Form of 5.300% Note due 2034 issued June 1, 2024 by Baltimore Gas and Electric	File No. 001-01910, Form 8-K dated June 06, 2024, Exhibit 4.1
4-14	Form of 5.650% Note due 2054 issued June 1, 2024 by Baltimore Gas and Electric	File No. 001-01910, Form 8-K dated June 06, 2024, Exhibit 4.2
4-15	Form of 5.450% Note due 2035 issued May 16, 2025 by Baltimore Gas and Electric	File No. 001-01910, Form 8-K dated May 16, 2025, Exhibit 4.2
4-15-1	Indenture, dated as of September 1, 2019, between Baltimore Gas and Electric Company and U.S. Bank N.A., as trustee	File No. 001-01910, Form 8-K dated September 12, 2019, Exhibit 4.1

Commonwealth Edison Company

Exhibit No.	Description	Location
4-16	Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944	Registration No. 2-60201, Form S-7, Exhibit 2-1[a]
4-16-1	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of January 13, 2003	File No. 001-01839, Form 8-K dated February 13, 2003, Exhibit 4.4

Exhibit No.	Description	Location
4-16-2	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 22, 2006	File No. 001-01839, Form 8-K dated March 6, 2006, Exhibit 4.1
4-16-3	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of March 1, 2007	File No. 001-01839, Form 8-K dated March 23, 2007, Exhibit 4.1
4-16-4	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of December 20, 2007	File No. 001-01839, Form 8-K dated January 16, 2008, Exhibit 4.1
4-16-5	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of September 17, 2012	File No. 001-01839, Form 8-K dated October 1, 2012, Exhibit 4.1
4-16-6	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of August 1, 2013	File No. 001-01839, Form 8-K dated August 19, 2013, Exhibit 4.1
4-16-7	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of January 2, 2014	File No. 001-01839, Form 8-K dated January 10, 2014, Exhibit 4.1
4-16-8	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 18, 2015	File No. 001-01839, Form 8-K dated March 2, 2015, Exhibit 4.1
4-16-9	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of November 4, 2015	File No. 001-01839, Form 8-K dated November 19, 2015, Exhibit 4.1
4-16-10	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of June 15, 2016	File No. 001-01839, Form 8-K dated June 27, 2016, Exhibit 4.1
4-16-11	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of August 9, 2017	File No. 001-01839, Form 8-K dated August 23, 2017, Exhibit 4.1
4-16-12	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 6, 2018	File No. 001-01839, Form 8-K dated February 20, 2018, Exhibit 4.1
4-16-13	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of July 26, 2018	File No. 001-01839, Form 8-K dated August 14, 2018, Exhibit 4.1
4-16-14	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 7, 2019	File No. 001-01839, Form 8-K dated February 19, 2019, Exhibit 4.1
4-16-15	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of October 29, 2019	File No. 001-01839, Form 8-K dated November 12, 2019, Exhibit 4.1
4-16-16	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 10, 2020	File No. 001-01839, Form 8-K dated February 25, 2020, Exhibit 4.1

Exhibit No.	Description	Location
4-16-17	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 16, 2021	File No. 001-01839, Form 8-K dated March 9, 2021, Exhibit 4.1
4-16-18	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of August 2, 2021	File No. 001-01839, Form 8-K dated August 12, 2021, Exhibit 4.1
4-16-19	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of February 23, 2022	File No. 001-01839, Form 8-K/A dated March 15, 2022, Exhibit 4.1
4-16-20	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of December 21, 2022	File No. 001-01839, Form 8-K dated January 10, 2023, Exhibit 4.1
4-16-21	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of May 1, 2024	File No. 001-01839, Form 8-K dated May 13, 2024, Exhibit 4.1
4-16-22	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of May 1, 2025	File No. 001-01839, Form 8-K dated May 19, 2025, Exhibit 4.1
4-17	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee	File No. 001-01839, Form 10-K dated April 1, 2002, Exhibit 4.4.2
4-18	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual	File No. 001-01839, Form 10-K dated March 29, 1996, Exhibit 4.29
4-18-1	Description of ComEd Securities	File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.65

PECO Energy Company

Exhibit No.	Description	Location
4-19	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank N.A., as current successor trustee)	Registration No. 2-2281, Exhibit B-1[a]
4-19-1	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of December 1, 1941	Registration No. 2-4863, Exhibit B-1(h)[a]

Exhibit No.	Description	Location
4-19-2	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of April 15, 2004	File No. 000-16844, Form 10-Q dated September 30, 2004, Exhibit 4-1-1
4-19-3	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 15, 2006	File No. 000-16844, Form 8-K dated September 25, 2006, Exhibit 4.1
4-19-4	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of March 1, 2007	File No. 000-16844, Form 8-K dated March 19, 2007, Exhibit 4.1
4-19-5	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 1, 2014	File No. 000-16844, Form 8-K dated September 15, 2014, Exhibit 4.1
4-19-6	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 1, 2017	File No. 000-16844, Form 8-K dated September 18, 2017, Exhibit 4.1
4-19-7	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of February 1, 2018	File No. 000-16844, Form 8-K dated February 23, 2018, Exhibit 4.1
4-19-8	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 1, 2018	File No. 000-16844, Form 8-K dated September 11, 2018, Exhibit 4.1
4-19-9	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of August 15, 2019	File No. 000-16844, Form 8-K dated September 10, 2019, Exhibit 4.1
4-19-10	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of June 1, 2020	File No. 000-16844, Form 8-K dated June 8, 2020, Exhibit 4.1
4-19-11	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of February 15, 2021	File No. 000-16844, Form 8-K dated March 8, 2021, Exhibit 4.1
4-19-12	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 1, 2021	File No. 000-16844, Form 8-K dated September 14, 2021, Exhibit 4.1
4-19-13	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of May 1, 2022	File No. 000-16844, Form 8-K dated May 24, 2022, Exhibit 4.1
4-19-14	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of August 1, 2022	File No. 000-16844, Form 8-K dated August 23, 2022, Exhibit 4.1
4-19-15	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of June 1, 2023	File No. 001-16844, Form 8-K dated June 23, 2023, Exhibit 4.1

Exhibit No.	Description	Location
4-19-16	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of August 15, 2024	File No. 001-16844, Form 8-K dated September 10, 2024, Exhibit 4.1
4-19-17	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of August 15, 2025	File No. 001-16844, Form 8-K dated September 10, 2025, Exhibit 4.1
4-20	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank N.A., as Trustee	File No. 000-16844, Form 10-Q dated July 30, 2003, Exhibit 4.1
4-21	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank N.A., as Trustee, dated as of June 24, 2003	File No. 000-16844, Form 10-Q dated July 30, 2003, Exhibit 4.2
4-22	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust N.A., as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003	File No. 000-16844, Form 10-Q dated July 30, 2003, Exhibit 4.3

Atlantic City Electric Company

Exhibit No.	Description	Location
4-23	Mortgage and Deed of Trust, dated January 15, 1937, between Atlantic City Electric Company and The Bank of New York Mellon (formerly Irving Trust Company), as trustee	2-66280, Registration Statement dated December 21, 1979, Exhibit 2(a)[(a)]
4-23-1	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of June 1, 1949	2-66280, Registration Statement dated December 21, 1979, Exhibit 2(b)[(a)]
4-23-2	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of March 1, 1991	Form 10-K dated March 28, 1991, Exhibit 4(d)(1)[(a)]
4-23-3	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of April 1, 2004	File No. 001-03559, Form 8-K dated April 6, 2004, Exhibit 4.3
4-23-4	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of March 8, 2006	File No. 001-03559, Form 8-K dated March 17, 2006, Exhibit 4
4-23-5	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of October 9, 2018	File No. 001-03559, Form 8-K dated October 16, 2018, Exhibit 4.1
4-23-6	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of May 2, 2019	File No. 001-03559, Form 8-K dated May 21, 2019, File No. 4.3
4-23-7	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of June 1, 2020	File No. 001-03559, Form 8-K dated June 9, 2020, Exhibit 4.2
4-23-8	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of February 15, 2021	File No. 001-03559, Form 8-K dated March 10, 2021, Exhibit 4.1
4-23-9	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of November 1, 2021	File No. 001-03559, Form 8-K dated November 16, 2021, Exhibit 4.2
4-23-10	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of February 1, 2022	File No. 001-03559, Form 8-K dated February 15, 2022, Exhibit 4.2
4-23-11	Supplemental Indenture to the Atlantic City Electric Company Mortgage and Deed of Trust, dated as of March 1, 2023	File No. 001-03559, Form 8-K dated March 15, 2023, Exhibit 4.2
4-23-12	Supplemental Indenture to the Atlantic City Electric Company Mortgage and Deed of Trust, dated as of March 1, 2024	File No. 001-03559, Form 8-K dated March 20, 2024, Exhibit 4.2
4-23-13	Supplemental Indenture to the Atlantic City Electric Company Mortgage and Deed of Trust, dated as of March 1, 2025	File No. 001-03559, Form 8-K dated March 26, 2025, Exhibit 4.2
4-24	Pollution Control Facilities Loan Agreement, dated as of June 1, 2020, between The Pollution Control Financing Authority of Salem County and Atlantic City Electric	File No. 001-03559, Form 8-K dated June 2, 2020, Exhibit 4.1

Delmarva Power & Light Company

Exhibit No.	Description	Location
4-25	Mortgage and Deed of Trust of Delaware Power & Light Company to The Bank of New York Mellon (ultimate successor to the New York Trust Company), as trustee, dated as of October 1, 1943, and copies of the First through Sixty-Eighth Supplemental Indentures thereto	33-1763, Registration Statement dated November 27, 1985, Exhibit 4-(A)[(a)]
4-25-1	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of October 1, 1993	33-53855, Registration Statement dated January 30, 1995, Exhibit 4-L[(a)]
4-25-2	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of October 1, 1994	33-53855, Registration Statement dated January 30, 1995, Exhibit 4-N[(a)]
4-25-3	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of May 4, 2015	File No. 001-01405, Form 8-K dated May 5, 2015, Exhibit 4.2
4-25-4	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of December 5, 2016	File No. 001-01405, Form 8-K dated December 12, 2016, Exhibit 4.2
4-25-5	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of June 1, 2018	File No. 001-01405, Form 8-K dated June 21, 2018, Exhibit 4.2
4-25-6	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of May 2, 2019	File No. 001-01405, Form 8-K dated December 12, 2019, Exhibit 4.2
4-25-7	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of January 1, 2020	File No. 001-01405, Form 10-Q dated May 8, 2020, Exhibit 4.4
4-25-8	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of June 1, 2020	File No. 001-01405, Form 8-K dated June 9, 2020, Exhibit 4.4
4-25-9	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of February 15, 2021	File No. 001-01405, Form 8-K dated March 30, 2021, Exhibit 4.4
4-25-10	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of February 1, 2022	File No. 001-01405, Form 8-K dated February 15, 2022, Exhibit 4.4
4-25-11	Supplemental Indenture to Delmarva Power & Light Company Mortgage dated as of January 1, 2022	File No. 001-01405, Form 10-Q dated May 9, 2022, Exhibit 4.1

Exhibit No.	Description	Location
4-25-12	Supplemental Indenture to the Delmarva Power & Light Company Mortgage and Deed of Trust, dated as of March 1, 2023	File No. 001-01405, Form 8-K dated March 15, 2023, Exhibit 4.4
4-25-13	Supplemental Indenture to the Delmarva Power & Light Company Mortgage and Deed of Trust, dated as of March 1, 2024	File No. 001-01405, Form 8-K dated March 20, 2024, Exhibit 4.4
4-25-14	Supplemental Indenture to the Delmarva Power & Light Company Mortgage and Deed of Trust, dated as of March 1, 2025	File No. 001-01405, Form 8-K dated March 26, 2025, Exhibit 4.4
4-26	Gas Facilities Loan Agreement, dated as of July 1, 2020, between The Delaware Economic Development Authority and Delmarva Power & Light Company	File No. 001-01405, Form 8-K dated July 1, 2020, Exhibit 4.1

Potomac Electric Power Company

Exhibit No.	Description	Location
4-27	Mortgage and Deed of Trust, dated July 1, 1936, of Potomac Electric Power Company to The Bank of New York Mellon as successor trustee, securing First Mortgage Bonds of Potomac Electric Power Company, and Supplemental Indenture dated July 1, 1936	File No. 2-2232, Registration Statement dated June 19, 1936, Exhibit B-4[a]
4-27-1	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of December 10, 1939	8-K dated January 3, 1940, Exhibit B[a]
4-27-2	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of March 16, 2004	File No. 001-01072, Form 8-K dated March 23, 2004, Exhibit 4.3
4-27-3	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of May 24, 2005	File No. 001-01072, Form 8-K dated May 26, 2005, Exhibit 4.2
4-27-4	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of November 13, 2007	File No. 001-01072, Form 8-K dated November 15, 2007, Exhibit 4.2
4-27-5	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of March 24, 2008	File No. 001-01072, Form 8-K dated March 28, 2008, Exhibit 4.1
4-27-6	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of December 3, 2008	File No. 001-01072, Form 8-K dated December 8, 2008, Exhibit 4.2
4-27-7	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of March 11, 2013	File No. 001-01072, Form 8-K dated March 12, 2013, Exhibit 4.2

Exhibit No.	Description	Location
4-27-8	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of November 14, 2013	File No. 001-01072, Form 8-K dated November 15, 2013, Exhibit 4.2
4-27-9	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of March 9, 2015	File No. 001-01072, Form 8-K dated March 10, 2015, Exhibit 4.3
4-27-10	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of May 15, 2017	File No. 001-01072, Form 8-K dated May 22, 2017, Exhibit 4.2
4-27-11	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of June 1, 2018	File No. 001-01072, Form 8-K dated June 21, 2018, Exhibit 4.2
4-27-12	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of May 2, 2019	File No. 001-01072, Form 8-K dated June 13, 2019, Exhibit 4.2
4-27-13	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of February 12, 2020	File No. 001-01072, Form 8-K dated February 25, 2020, Exhibit 4.2
4-27-14	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of February 15, 2021	File No. 001-01072, Form 8-K dated March 30, 2021, Exhibit 4.4
4-27-15	Supplemental Indenture to Potomac Electric Power Company Mortgage dated as of March 1, 2022	File No. 001-01072, Form 8-K dated March 24, 2022, Exhibit 4.2
4-27-16	Supplemental Indenture to the Potomac Electric Power Company Mortgage and Deed of Trust, dated as of March 1, 2023	File No. 001-01072, Form 8-K dated March 15, 2023, Exhibit 4.6
4-27-17	Supplemental Indenture to the Potomac Electric Power Company Mortgage and Deed of Trust, dated as of February 15, 2024	File No. 001-01072, Form 8-K dated March 4, 2024, Exhibit 4.3
4-27-18	Supplemental Indenture to the Potomac Electric Power Company Mortgage and Deed of Trust, dated as of March 1, 2025	File No. 001-01072, Form 8-K dated March 26, 2025, Exhibit 4.6
4-28	Exempt Facilities Loan Agreement dated as of June 1, 2019 between the Maryland Economic Development Corporation and Potomac Electric Power Company	File No. 001-01072, Form 8-K dated June 27, 2019, Exhibit 4.1

(10) Material Contracts

Exelon Corporation

Exhibit No.	Description	Location
10-1	Transition Services Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation	File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 10.1

Exhibit No.	Description	Location
10-2	Tax Matters Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation	File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 10.2
10-3	Employee Matters Agreement, dated January 31, 2022, between Exelon Corporation and Constellation Energy Corporation	File No. 001-16169, Form 8K dated February 2, 2022, Exhibit 10.3
10-4	Amended and Restated Credit Agreement for $900,000,000 dated August 29, 2024, between Exelon Corporation and various financial institutions	File No. 001-16169, Form 10-K dated October 30, 2024, Exhibit 10.1
10-5	Exelon Corporation Non-Employee Directors' Restricted Stock Unit Plan (Effective January 1, 2026)	Filed herewith.
10-6	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) *	File No. 001-16169, Form 10-K dated February 6, 2009, Exhibit 10.19
10-7	Exelon Corporation Employee Stock Purchase Plan, as amended and restated effective September 25, 2019	File No. 001-16169, Form 10-Q dated October 31, 2019, Exhibit 10.3
10-8	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries, as amended and restated effective September 25, 2019	File No. 001-16169, Form 10-Q dated October 31, 2019, Exhibit 10.4
10-9	Exelon Corporation 2020 Long-Term Incentive Plan (Effective April 28, 2020)	File No. 001-16169, Proxy Statement dated March 18, 2020, Appendix A
10-10	Exelon Corporation 2020 Long-Term Incentive Plan Prospectus, dated May 27, 2020	File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.3
10-11	Form of Restricted Stock Unit Award Notice and Agreement under the Exelon Corporation 2020 Long-Term Incentive Plan	File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.4
10-12	Form of Performance Share Award Notice and Agreement under the Exelon Corporation 2020 Long-Term Incentive Plan	File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.5
10-13	Exelon Corporation Senior Management Severance Plan as Amended and Restated effective February 1, 2024	File No. 001-16169, Form 10-K dated February 21, 2024, Exhibit 10.15.1
10-14	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2020)	File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 10.21

Exhibit No.	Description	Location
10-15	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 *	File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.52
10-15-1	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 *	File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.53
10-16	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective December 1, 2025)	Filed herewith
10-17	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective September 25, 2019)	File No. 001-16169, Form 10-Q dated October 31, 2019, Exhibit 10.5
10-18	2023 Amendment to Certain Plans of Exelon Corporation	File No. 001-16169, Form 10-K dated February 24, 2021, Exhibit 10.22
10-19	Constellation Energy Group Benefits Restoration Plan (As Amended and Restated Effective January 1, 2025)	File No. 001-16169, Form 10-K dated February 12, 2025, Exhibit 10.20
10-20	Exelon Corporation Unfunded Deferred Compensation Plan for Directors (As Amended and Restated Effective January 1, 2026)	Filed herewith

Commonwealth Edison Company

Exhibit No.	Description	Location
10-21	Deferred Prosecution Agreement, dated July 17, 2020, between Commonwealth Edison Company and the U.S. Department of Justice and the U.S. Attorney for the Northern District of Illinois	File No. 001-01839, Form 8-K dated July 17, 2020, Exhibit 10.1
10-22	Amended and Restated Credit Agreement for $1,000,000,000 dated August 29, 2024, between Commonwealth Edison Company and various financial institutions	File No. 001-01839, Form 10-K dated October 30, 2024, Exhibit 10.2

Baltimore Gas and Electric Company

Exhibit No.	Description	Location
10-23	Amended and Restated Credit Agreement for $600,000,000 dated August 29, 2024, between Baltimore Gas and Electric Company and various financial institutions	File No. 001-01910, Form 10-K dated October 30, 2024, Exhibit 10.4

PECO Energy Company

Exhibit No.	Description	Location
10-24	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009)	File No. 000-16844, Form 10-K dated February 6, 2009, Exhibit 10.20
10-25	Amended and Restated Credit Agreement for $600,000,000 dated August 29, 2024, between PECO Energy Company and various financial institutions	File No. 000-16844, Form 10-K dated October 30, 2024, Exhibit 10.3

Atlantic City Electric Company, Potomac Electric Power Company, Delmarva Power & Light Company

Exhibit No.	Description	Location
10-26	Bond Purchase Agreement, dated December 1, 2015, among Atlantic City Electric Company and the purchasers signatory thereto	File No. 001-03559, Form 8-K dated December 2, 2015, Exhibit 1.1
10-27	Amended and Restated Credit Agreement for $900,000,000 dated August 29, 2024, between Potomac Electric Power Company, Delmarva Power & Light Company, Atlantic City Electric Company and various financial institutions	File Nos. 001-010172, 001-01405, 001-03559, Form 10-K dated October 30, 2024, Exhibit 10.5

(14) Code of Ethics

Exelon Corporation

Exhibit No.	Description	Location
14-1	Exelon Code of Conduct, as amended January 05, 2026	Filed herewith.

(19) Insider trading policies and procedures

Exelon Corporation

Exhibit No.	Description	Location
19-1	Exelon Insider Trading Policy	Filed herewith.

(97) Policy Relating to Recovery of Erroneously Awarded Compensation

Exelon Corporation

Exhibit No.	Description	Location
97-1	Exelon Financial Restatement Compensation Recoupment Policy	File No. 001-16169, Form 10-K dated February 21, 2024, Exhibit 97.1

Exhibit No.	Description
	Subsidiaries
21-1	Exelon Corporation
21-2	Commonwealth Edison Company
21-3	PECO Energy Company

Exhibit No.	Description
21-4	Baltimore Gas and Electric Company
21-5	Pepco Holdings LLC
21-6	Potomac Electric Power Company
21-7	Delmarva Power & Light Company
21-8	Atlantic City Electric Company
	Consent of Independent Registered Public Accountants
23-1	Exelon Corporation
23-2	Commonwealth Edison Company
23-3	PECO Energy Company
23-4	Baltimore Gas and Electric Company
	Power of Attorney (Exelon Corporation)
24-1	Anna Richo
24-2	Calvin G. Butler, Jr.
24-3	W. Paul Bowers
24-4	Marjorie Rodgers Cheshire
24-5	Matthew Rogers
24-6	Linda P. Jojo
24-7	Charisse R. Lillie
24-8	Bryan Segedi
24-9	David G. DeWalt
	Power of Attorney (Commonwealth Edison Company)
24-10	Michael A. Innocenzo
24-11	Elizabeth Buchanan
24-12	Stephen Bowman
24-13	Ricardo Estrada
24-14	Zaldwaynaka Scott
24-15	Smita Shah
24-16	Gil C. Quiniones
	Power of Attorney (PECO Energy Company)
24-17	Michael A. Innocenzo
24-18	John S. Grady
24-19	David M. Vahos
24-20	Sharmain Matlock-Turner
24-21	Michael Nutter

Exhibit No.	Description
24-22	Michelle Hong
24-23	Roberto E. Perez
	Power of Attorney (Baltimore Gas and Electric Company)
24-24	Michael A. Innocenzo
24-25	Tamla A. Olivier
24-26	Keith Lee
24-27	Rachel Garbow Monroe
24-28	Byron Marchant
24-29	Tim Regan
24-30	Amy Seto
24-31	Maria Harris Tildon
	Power of Attorney (Pepco Holdings LLC)
24-32	Antoine Allen
24-33	J. Tyler Anthony
24-34	Michael A. Innocenzo
24-35	Debra P. DiLorenzo
24-36	Benjamin Wu
24-37	Linda W. Cropp
24-38	Rosie Allen-Herring
	Power of Attorney (Potomac Electric Power Company)
24-39	J. Tyler Anthony
24-40	Elizabeth Morgan Downs O'Donnell
24-41	Michael A. Innocenzo
24-42	Rodney Oddoye
24-43	Amber Perry
24-44	Jaclyn Cantler
24-45	Anne C. Bancroft
	Power of Attorney (Delmarva Power & Light Company)
24-46	J. Tyler Anthony
24-47	Michael A. Innocenzo
	Power of Attorney (Atlantic City Electric Company)
24-48	J. Tyler Anthony

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10-K for the year ended December 31, 2025 filed by the following officers for the following registrants:

Exhibit No.	Description
31-1	Filed by Calvin G. Butler, Jr. for Exelon Corporation
31-2	Filed by Jeanne M. Jones for Exelon Corporation
31-3	Filed by Gil C. Quiniones for Commonwealth Edison Company
31-4	Filed by Joshua S. Levin for Commonwealth Edison Company
31-5	Filed by David M. Vahos for PECO Energy Company
31-6	Filed by Marissa E. Humphrey for PECO Energy Company
31-7	Filed by Tamla A. Olivier for Baltimore Gas and Electric Company
31-8	Filed by Michael J. Cloyd for Baltimore Gas and Electric Company
31-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
31-10	Filed by Elizabeth Morgan Downs O'Donnell for Pepco Holdings LLC
31-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
31-12	Filed by Elizabeth Morgan Downs O'Donnell for Potomac Electric Power Company
31-13	Filed by J. Tyler Anthony for Delmarva Power & Light Company
31-14	Filed by Elizabeth Morgan Downs O'Donnell for Delmarva Power & Light Company
31-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
31-16	Filed by Elizabeth Morgan Downs O'Donnell for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10-K for the year ended December 31, 2025 filed by the following officers for the following registrants:

Exhibit No.	Description
32-1	Filed by Calvin G. Butler, Jr. for Exelon Corporation
32-2	Filed by Jeanne M. Jones for Exelon Corporation
32-3	Filed by Gil C. Quiniones for Commonwealth Edison Company
32-4	Filed by Joshua S. Levin for Commonwealth Edison Company
32-5	Filed by David M. Vahos for PECO Energy Company
32-6	Filed by Marissa E. Humphrey for PECO Energy Company
32-7	Filed by Tamla A. Olivier for Baltimore Gas and Electric Company
32-8	Filed by Michael J. Cloyd for Baltimore Gas and Electric Company
32-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
32-10	Filed by Elizabeth Morgan Downs O'Donnell for Pepco Holdings LLC
32-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
32-12	Filed by Elizabeth Morgan Downs O'Donnell for Potomac Electric Power Company
32-13	Filed by J. Tyler Anthony for Delmarva Power & Light Company
32-14	Filed by Elizabeth Morgan Downs O'Donnell for Delmarva Power & Light Company

Exhibit No.	Description
32-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
32-16	Filed by Elizabeth Morgan Downs O'Donnell for Atlantic City Electric Company
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 Labels 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)

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

(a) These filings are not available electronically on the SEC website as they were filed in paper previous to the electronic system that is currently in place.

ITEM 16. FORM 10-K SUMMARY

All Registrants

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

EXELON CORPORATION

By: /s/ CALVIN G. BUTLER JR.
Name: Calvin G. Butler Jr.
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	Title
/s/ CALVIN G. BUTLER JR. Calvin G. Butler Jr.	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ JEANNE M. JONES Jeanne M. Jones	Executive Vice President, Chief Finance Officer, Audit and Risk (Principal Financial Officer)
/s/ ROBERT A. KLECZYNSKI Robert A. Kleczynski	Senior Vice President, Controller and Tax (Principal Accounting Officer)

This annual report has also been signed below by Colette D. Honorable, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anna Richo	**Linda P. Jojo**
W. Paul Bowers	**Charisse R. Lillie**
Marjorie Rodgers Cheshire	**Bryan Segedi**
Matthew Rogers	**David G. DeWalt**

By: /s/ COLETTE D. HONORABLE February 12, 2026
Name: Colette D. Honorable

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

COMMONWEALTH EDISON COMPANY

By: /s/ GIL C. QUINIONES
Name: Gil C. Quiniones
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	**Title**
/s/ GIL C. QUINIONES Gil C. Quiniones	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ JOSHUA S. LEVIN Joshua S. Levin	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ ERIN V. WHITE Erin V. White	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by Gil C. Quiniones, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Michael A. Innocenzo	**Ricardo Estrada**
Elizabeth Buchanan	**Zaldwaynaka Scott**
Stephen Bowman	**Smita Shah**

By: /s/ GIL C. QUINIONES February 12, 2026
Name: Gil C. Quiniones

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

PECO ENERGY COMPANY

By:	/s/ DAVID M. VAHOS
Name:	David M. Vahos
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	Title
/s/ DAVID M. VAHOS David M. Vahos	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ MARISSA E. HUMPHREY Marissa E. Humphrey	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ MARIANA HUFFORD Mariana Hufford	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by David M. Vahos, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Michael A. Innocenzo	**Michael Nutter**
John S. Grady	**Michelle Hong**
Sharmain Matlock-Turner	**Roberto E. Perez**

By:	/s/ DAVID M. VAHOS	February 12, 2026
Name:	David M. Vahos	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

BALTIMORE GAS AND ELECTRIC COMPANY

By:	/s/ TAMLA A. OLIVIER
Name:	Tamla A. Olivier
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	Title
/s/ TAMLA A. OLIVIER Tamla A. Olivier	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ MICHAEL J. CLOYD Michael J. Cloyd	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DAMON M. SCOLERI Damon M. Scoleri	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by Tamla A. Olivier, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Michael A. Innocenzo	**Tim Regan**
Keith Lee	**Amy Seto**
Rachel Garbow Monroe	**Maria Harris Tildon**
Byron Marchant	

By:	/s/ TAMLA A. OLIVIER	February 12, 2026
Name:	Tamla A. Olivier	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

PEPCO HOLDINGS LLC

By:	/s/ J. TYLER ANTHONY
Name:	J. Tyler Anthony
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ ELIZABETH MORGAN DOWNS O'DONNELL Elizabeth Morgan Downs O'Donnell	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES Jason T. Jones	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by J. Tyler Anthony, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Antoine Allen	**Benjamin Wu**
Michael A. Innocenzo	**Linda W. Cropp**
Debra P. DiLorenzo	**Rosie Allen-Herring**

By:	/s/ J. TYLER ANTHONY	February 12, 2026
Name:	J. Tyler Anthony	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

POTOMAC ELECTRIC POWER COMPANY

By: /s/ J. TYLER ANTHONY
Name: J. Tyler Anthony
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ ELIZABETH MORGAN DOWNS O'DONNELL Elizabeth Morgan Downs O'Donnell	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer), and Director
/s/ JASON T. JONES Jason T. Jones	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by J. Tyler Anthony, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Michael A. Innocenzo
Rodney Oddoye
Amber Perry
Jacyln Cantler
Anne C. Bancroft

By: /s/ J. TYLER ANTHONY February 12, 2026
Name: J. Tyler Anthony

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

DELMARVA POWER & LIGHT COMPANY

By:	/s/ J. TYLER ANTHONY
Name:	J. Tyler Anthony
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	**Title**
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ ELIZABETH MORGAN DOWNS O'DONNELL Elizabeth Morgan Downs O'Donnell	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES Jason T. Jones	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by J. Tyler Anthony, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Michael A. Innocenzo

By:	/s/ J. TYLER ANTHONY	February 12, 2026
Name:	J. Tyler Anthony	

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 12th day of February, 2026.

ATLANTIC CITY ELECTRIC COMPANY

By:	/s/ J. TYLER ANTHONY
Name:	J. Tyler Anthony
Title:	President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the Registrant and in the capacities indicated on the 12th day of February, 2026.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer), and Director
/s/ ELIZABETH MORGAN DOWNS O'DONNELL Elizabeth Morgan Downs O'Donnell	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JASON T. JONES Jason T. Jones	Director, Accounting (Principal Accounting Officer)