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, 2023
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) P.O. Box 8699 2301 Market Street 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
PECO ENERGY COMPANY:		
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	EXC/28	New York Stock Exchange

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, 2023 was as follows:

Exelon Corporation Common Stock, without par value	$40,536,144,047
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, 2024 was as follows:

Exelon Corporation Common Stock, without par value	999,538,542
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,399
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 2023 Annual Meeting of Shareholders and the Commonwealth Edison Company 2023 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.

TABLE OF CONTENTS

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
Generation or CEG	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)
CENG	Constellation Energy Nuclear Group, LLC

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

2022 Form 10-K	The Registrants' Annual Report on Form 10-K for the year ended December 31, 2022 filed with the SEC on February 14, 2023
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
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
DOEE	Department of Energy & Environment
DPA	Deferred Prosecution Agreement
DPP	Deferred Purchase Price
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ERP	Enterprise Resource Program
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
IIJA	Infrastructure Investment and Jobs Act
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
MMG	Middle Mile Grant
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
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
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
RTEP	Regional Transmission Expansion Plan
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
STRIDE	Maryland Strategic Infrastructure Development and Enhancement Program
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.

The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, including those factors discussed with respect to the Registrants discussed in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 18, Commitments and Contingencies, and (d) other factors discussed in filings with the SEC by the Registrants.

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 ComEd, PECO, BGE, Pepco, DPL, and ACE.

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation. The separation was completed on February 1, 2022, creating two publicly traded companies, Exelon and Constellation. See Note 2 – Discontinued Operations of the Combined Notes to Consolidated Financial Statements for additional information.

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, 2023:

	ComEd	PECO	BGE	Pepco	DPL	ACE
Service Territories (in square miles)						
Electric	11,450	1,900	2,300	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	9.2	4.1	3.0	2.4	1.5	1.2
Natural Gas	N/A	2.5	2.9	N/A	0.6	N/A
Total[(b)]	9.2	4.1	3.2	2.4	1.5	1.2
Main City	Chicago	Philadelphia	Baltimore	District of Columbia	Wilmington	Atlantic City
Main City Population	2.6	1.6	0.6	0.7	0.1	0.1
Number of Customers (in millions)						
Electric	4.1	1.7	1.3	0.9	0.6	0.6
Natural Gas	N/A	0.6	0.7	N/A	0.1	N/A
Total[(c)]	4.1	1.7	1.3	0.9	0.6	0.6

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(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 MD'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 force 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. ComEd is in the process of pursuing a new agreement with the City.

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 eliminate 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 materially 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. ComEd recovers costs through a performance-based rate formula. ComEd is required to file an update to the performance-based rate formula on an annual basis. On September 15, 2021, Illinois passed CEJA, which contains requirements for ComEd to transition away from the performance-based rate formula by the end of 2022 and would allow for the submission of either a general rate or multi-year rate plan. On February 3, 2022, the ICC approved a tariff that establishes the process under which ComEd will reconcile its 2022 and 2023 rate year revenue requirements with actual costs. ComEd's electric distribution costs are currently recovered through a multi-year rate plan with case proceedings as filed with the ICC. PECO's and DPL's electric and gas distribution costs and ACE's electric distribution costs have generally been recovered through rate case proceedings, with PECO utilizing a fully projected future test year while DPL and ACE utilize a 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 certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies. See Note 3 — 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 3 — 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 445,000 mmcf, 268,000 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%, 42%, and 33% of PECO's, BGE's, and DPL's 2023-2024 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 the 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. Beginning in 2024, BGE, Pepco, and DPL will begin deferring less energy efficiency and demand response program costs to a regulatory asset. See Note 3 — 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 2024 capital expenditures.

Transmission Services

Under FERC's open access transmission policy, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates 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 FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Tariff. PJM operates the PJM energy, capacity, and other markets, and, through central dispatch, 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 using the transmission facilities of the PJM transmission owners.

The Utility Registrants' transmission rates are based on a FERC approved formula and established on an annual basis as shown below:

	Approval Date
ComEd	January 2008
PECO	December 2019
BGE	April 2006
Pepco	April 2006
DPL	April 2006
ACE	April 2006

Exelon's Strategy and Outlook

Following the separation on February 1, 2022, Exelon is now a transmission and distribution company, focused on delivering 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 reliability and resiliency and that 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 $35 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, and transmission projects, which is projected to result in an increase to current rate base of approximately $19 billion by the end of 2027. 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 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 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 market, financial, regulatory, legislative, and operational 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

The Registrants strive to create a workplace culture that promotes and embodies diversity, inclusion, innovation, and safety for their employees. In order to provide the services and products that their customers expect, the Registrants aspire to create teams that reflect the diversity of the communities that the Registrants serve. Therefore, the Registrants take steps to attract and retain highly qualified and diverse talent and seek to create hiring and promotion practices that are equitable and neutralize any bias, including unconscious bias. The Registrants provide growth opportunities, competitive compensation and benefits, and a variety of training and development programs. The Registrants are committed to helping all employees grow their skills and careers largely through numerous training opportunities, mentorship programs, continuous feedback and development discussions, and evaluations. Employees are encouraged to thrive outside the workplace as well. The Registrants provide a full suite of wellness benefits targeted at supporting work-life balance, physical, mental and financial health, and industry-leading paid leave policies.

The Registrants typically conduct an employee engagement survey every other year to help identify organizational strengths and areas of opportunity for growth. The survey results are reviewed with senior management and the Exelon Board of Directors.

Diversity Metrics

The following tables show diversity metrics for all employees and management as of December 31, 2023.

Employees	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Female[(a)(b)]	5,637	1,672	813	808	1,320	335	137	107
People of Color[(a)(b)]	8,174	2,822	1,084	1,273	1,895	867	233	158
Aged <30	2,295	817	406	319	460	157	107	65
Aged 30-50	11,189	3,976	1,592	1,914	2,352	754	491	351
Aged >50	6,478	1,881	1,040	1,062	1,471	443	320	205
Total Employees[(c)]	19,962	6,674	3,038	3,295	4,283	1,354	918	621

Management[(d)]	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Female[(a)(b)]	1,159	268	146	138	251	58	14	21
People of Color[(a)(b)]	1,303	388	143	190	313	119	35	30
Aged <30	21	4	4	3	5	1	1	2
Aged 30-50	2,045	580	208	314	447	123	63	45
Aged >50	1,410	384	173	172	292	66	44	40
Within 10 years of retirement eligibility	1,998	551	228	244	412	102	58	58
Total Employees in Management[(c)]	3,476	968	385	489	744	190	108	87

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(a) To effectuate Exelon's pay equity goals, Exelon conducts analysis on gender and racial pay equity.
(b) Information concerning women and people of color is based on self-disclosed information.
(c) Total employees represents the sum of the aged categories.
(d) Management is defined as executive/senior level officials and managers as well as all employees who have direct reports and/or supervisory responsibilities.

Turnover Rates

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

The table below shows the average turnover rate for all employees for the last three years of 2021 to 2023.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Retirement Age	3.41 %	3.84 %	3.97 %	2.85 %	3.36 %	3.20 %	3.71 %	3.79 %
Voluntary	3.07 %	2.63 %	2.92 %	2.08 %	2.83 %	3.25 %	1.73 %	2.29 %
Non-Voluntary	0.87 %	0.73 %	1.13 %	0.88 %	1.08 %	1.76 %	0.66 %	0.75 %

Collective Bargaining Agreements

Approximately 43% of Exelon’s employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2023.

	Total Employees Covered by CBAs	Number of CBAs	CBAs New and Renewed in 2023[(a)]	Total Employees Under CBAs New and Renewed in 2023
Exelon	8,555	10	2	1,813
ComEd	3,583	2	—	—
PECO	1,438	2	—	—
BGE	1,433	1	1	1,433
PHI	2,096	5	1	380
Pepco	860	1	—	—
DPL	637	2	—	—
ACE	405	2	1	380

(a) Does not include CBAs that were extended in 2023 while negotiations are ongoing for renewal.

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 CEO; 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 ESG 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 supports the EPA moving forward with meaningful regulation of GHG emissions under the Clean Air Act.

The Registrants currently are subject to, and may become subject to additional, federal and/or state legislation 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 2022, Exelon's Scope 1 and 2 GHG emissions, were just over 5.7 million metric tons carbon dioxide equivalent using the World Resources Institute Corporate Standard Market-based accounting. Of these emissions, 0.5 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 Registrants PECO, BGE, and DPL. The remaining 5.2 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 Net-Zero by 2050. Exelon is laying the groundwork by partnering with national labs, universities and research consortia to research, develop, and pilot clean technologies that will be needed, as well as working with our states, jurisdictions and policy makers to understand the scope and scale of energy transformation, and needed policies and incentives, that will be 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. During 2024 - 2027, estimated customer program energy efficiency investments across the Utility Registrants total $5.1 billion. These programs enable customer savings through home energy audits, lighting discounts, 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 a goal to electrify 30% of their own vehicle fleet by 2025, increasing to 50% by 2030. Clean fuels and other emerging technologies can also support the transition, lessen the strain on electric system expansion, and support energy system resiliency. Exelon, and its registrants PECO, BGE, and DPL that 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. The energy transition may present challenges for the Utility Registrants and their service territories. 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 ITEM 1A. RISK FACTORS. The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry.

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 is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. On November 4, 2020, the United States formally withdrew from the Paris Agreement, but on January 20, 2021, President Biden accepted the Agreement, which resulted in the United States' formal re-entry on February 19, 2021. The United States has set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels by 2030. On November 11, 2022, at the UNFCCC Conference of the Parties (COP 27), President Biden recommitted the U.S. to these goals and detailed the significant domestic climate actions the U.S. had taken to spur a new era of clean American manufacturing, enhance energy security, and drive down the costs of clean energy for consumers in the U.S. and around the world.

Federal Climate Change Legislation and Regulation. On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA), which, among other things, aims to reduce U.S. carbon emissions and promote economic development through investments in clean and renewable energy projects. The consumer-facing clean energy tax credits created or expanded by the IRA are intended to drive rapid adoption of energy efficiency, electric transportation, and solar energy which would require Exelon's utilities to expand and modernize infrastructure, systems and services to integrate and optimize these resources.

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, Pennsylvania, Rhode Island, Vermont, Virginia) 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 CO2 emissions. Non-emitting resources do not have to purchase or hold these allowances. Pennsylvania joined RGGI in April 2022.

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 5-year and 30-year decarbonization programs and strategies. 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. 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 3 — 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.

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 3 — 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.

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 releases of hazardous substances and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of hazardous waste at sites, many of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight. Most states have also enacted statutes that contain provisions substantially 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 2024 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 $36 million which consists primarily of $25 million at ComEd.

As of December 31, 2023, 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 3 — Regulatory Matters and Note 18 — 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 21, 2024

Exelon

Name	Age	Position	Period
Butler Jr., Calvin G.	54	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
		Chief Executive Officer, BGE	2014 - 2019
Jones, Jeanne	44	Executive Vice President and Chief Financial Officer, Exelon	2022 - Present
		Senior Vice President, Corporate Finance, Exelon	2021 - 2022
		Senior Vice President and Chief Financial Officer, ComEd	2018 - 2021
Glockner, David	63	Executive Vice President, Compliance, Audit and Risk, Exelon	2020 - Present
		Chief Compliance Officer, Citadel LLC	2017 - 2020
Littleton, Gayle E.	51	Executive Vice President, Chief Legal Officer, and Corporate Secretary, Exelon	2020 - Present
		Partner, Jenner & Block LLP	2015 - 2020
Quiniones, Gil C.	57	Chief Executive Officer, ComEd	2021 - Present
		President, ComEd	2024 - Present
		President and Chief Executive Officer, New York Power Authority	2011 - 2021
Innocenzo, Michael A.	58	President and Chief Executive Officer, PECO	2018 - Present
Khouzami, Carim V.	49	President, BGE	2021 - Present
		Chief Executive Officer, BGE	2019 - Present
		Senior Vice President & COO, Exelon Utilities	2018 - 2019
Anthony, J. Tyler	59	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
Kleczynski, Robert A.	55	Senior Vice President, Controller and Tax, Exelon	2023 - Present
		Senior Vice President, Exelon	2020 - 2023
		Vice President, Exelon	2018 - 2020
		General Tax Officer, Exelon	2018 - 2023
David Velazquez	64	Executive Vice President, Operations and Technology, Exelon Business Services Company, LLC	2023 - Present
		Executive Vice President, Utility Operations, Exelon Business Services Company, LLC	2021 -2023
		President and Chief Executive Officer, PHI, Pepco, DPL, and ACE	2016 - 2021

ComEd

Name	Age	Position	Period
Quiniones, Gil	57	Chief Executive Officer, ComEd	2021 - Present
		President, ComEd	2024 - Present
		President and Chief Executive Officer, New York Power Authority	2011 - 2021
Perez, David R.	54	Executive Vice president and Chief Operating Officer, ComEd	2024 - Present
		Senior Vice President, Distribution Operations	2019 - 2023
Levin, Joshua	44	Senior Vice President, Chief Financial Officer & Treasurer, ComEd	2023 - Present
		Vice President, Financial, Planning and Analysis	2021 - 2023
		Director of Financial Planning and Analysis, ComEd	2019 - 2021
Rippie, E. Glenn	63	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 - 2021
		Partner and Chief Financial Officer, Rooney, Rippie & Ratnaswamy, LLP	2010 - 2019
Binswanger, Lewis	64	Senior Vice President, Governmental, Regulatory and External Affairs, ComEd	2022 - Present
		Vice President, External Affairs, Nicor Gas	2013 - 2022

PECO

Name	Age	Position	Period
Innocenzo, Michael A.	58	President and Chief Executive Officer, PECO	2018 - Present
Levine, Nicole	47	Senior Vice President and Chief Operations Officer, PECO	2022 - Present
		Vice President, Electrical Operations, PECO	2018 - 2022
Humphrey, Marissa	44	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
		Vice President, Finance, Exelon Utilities	2019 - 2020
		Vice President, Financial Planning and Analysis, PHI, Pepco, DPL, and ACE	2016 - 2019
Oliver, Douglas	49	Senior Vice President, Governmental, Regulatory and External Affairs, PECO	2023 - Present
		Vice President, Governmental and External Affairs, PECO	2019 - 2023
		Vice President, Communications, PECO	2018 - 2019
Gay, Anthony	58	Vice President and General Counsel, PECO	2019 - Present
		Vice President, Governmental and External Affairs, PECO	2016 - 2019

BGE

Name	Age	Position	Period
Khouzami, Carim V.	49	President, BGE	2021 - Present
		Chief Executive Officer, BGE	2019 - Present
		Senior Vice President & COO, Exelon Utilities	2018 - 2019
Dickens, Derrick	59	Senior Vice President and Chief Operating Officer, BGE	2021 - Present
		Senior Vice President, Customer Operations, PHI, Pepco, DPL, and ACE	2020 - 2021
		Vice President, Technical Services, BGE	2016 - 2020
Vahos, David M.	51	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
Núñez, Alexander G.	52	Senior Vice President, Governmental, Regulatory and External Affairs, BGE	2021 - Present
		Senior Vice President, Regulatory Affairs and Strategy, BGE	2020 - 2021
		Senior Vice President, Regulatory and External Affairs, BGE	2016 - 2020
Ralph, David	57	Vice President and General Counsel, BGE	2021 - Present
		Associate General Counsel, BGE	2019 - 2021
		Assistant General Counsel, Exelon	2017 - 2019

PHI, Pepco, DPL, and ACE

Name	Age	Position	Period
Anthony, J. Tyler	59	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
Olivier, Tamla	51	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE	2021 - Present
		Senior Vice President, Customer Operations, BGE	2020 - 2021
		Senior Vice President, Constellation NewEnergy, Inc.	2016 - 2020
Barnett, Phillip S.	60	Senior Vice President, Chief Financial Officer and Treasurer, PHI, Pepco, DPL, and ACE	2018 - Present
Oddoye, Rodney	47	Senior Vice President, Governmental, Regulatory and External Affairs, PHI, Pepco, DPL, and ACE	2021 - Present
		Senior Vice President, Governmental and External Affairs, BGE	2020 - 2021
		Vice President, Customer Operations, BGE	2018 - 2020
Bancroft, Anne	57	Vice President and General Counsel, PHI, Pepco, DPL, and ACE	2021 - Present
		Associate General Counsel, Exelon	2017 - 2021

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. Such risks, which could negatively affect one or more of the Registrants' 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.

Risks related to market and financial factors primarily include:

- the demand for electricity, reliability of service, and affordability in the markets where the Utility Registrants conduct their business,
- the ability of the Utility Registrants to operate their respective transmission and distribution assets, their ability to access capital markets, and the impacts on their results of operations, financial condition or liquidity/cash flows due to public health crises, epidemics or pandemics, and
- emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy.

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

- utility regulatory business models,
- energy, environmental, and climate policy, and
- tax policy.

Risks related to operational factors primarily include:

- changes in the global climate could produce extreme weather events, which could put the Registrant's facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services,
- the ability of the Utility Registrants to maintain the reliability, resiliency, and safety of their energy delivery systems, which could affect their ability to deliver energy to their customers and affect their operating costs, and
- physical and cyber security risks for the Utility Registrants as the owner-operators of transmission and distribution facilities.

Risks related to the separation primarily include:

- challenges to achieving the benefits of separation and
- performance by Exelon and Constellation under the transaction agreements, including indemnification responsibilities.

There may be further risks and uncertainties that are not presently known or that are not currently believed to be material that could negatively affect the Registrants' consolidated financial statements in the future.

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.

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 14 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information.

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, 2023, approximately 23%, 10%, and 16% 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 16 — 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 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 7 — Property, Plant, and Equipment, Note 11 — Asset Impairments, and Note 12 — 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.

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 for 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 lead 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 could be adjusted, subject to refund or disallowed, 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. 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 3 — 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 PJM’s RTEP and 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 and/or energy conservation legislation, along with energy conservation by customers (All Registrants).

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.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, 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 could cause declines in customer energy consumption and lead to a decline in the Registrants' earnings, if timely recovery is not allowed. 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 13 — 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 ones are summarized in Note 18 — 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.

The activities associated with the past Deferred Prosecution Agreement and the now resolved associated SEC investigation could have a material adverse effect on Exelon's and ComEd's

reputation and relationship with legislators, regulators, and customers that could affect their ability to achieve actions and approvals (Exelon and ComEd).

On July 17, 2020, ComEd entered into a Deferred Prosecution Agreement with the USAO for the Northern District of Illinois to resolve the USAO's investigation into Exelon's and ComEd's lobbying activities in the State of Illinois. Exelon was not made a party to the DPA and no charges were brought against Exelon. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provided that the USAO would defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period. That period expired, and the pending charge was dismissed, in July 2023. In October 2019, the SEC notified Exelon and ComEd that it had opened an investigation into their lobbying activities in the state of Illinois. On September 28, 2023, Exelon and ComEd reached a settlement with the SEC to fully resolve the matter.

The DPA and the settlement with the SEC could have a material adverse impact on Exelon's and ComEd's reputation or relationships with regulatory and legislative authorities, customers, and other stakeholders. Those impacts could affect, or make more difficult, their efforts to achieve actions or approvals associated with operations. See Note 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for more information regarding the DPA and SEC settlement.

Risks Related to Operational Factors

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 levels of precipitation, sea level rise, increased surface water temperatures, wildfires and/or other effects. Over time, the Registrants are making additional investments to protect their facilities from physical climate-related risks.

In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect Registrants' operations and business. Over time, the Registrants are making additional investments to adapt to changes in operational requirements to manage demand changes and customer expectations caused by climate change.

Climate Change 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, including through limitation of the use of natural gas. 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 — Climate Change and ITEM 1.A. "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" above for additional information.

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 are increasing. Threat actors, including sophisticated nation-state actors, continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry, grid infrastructure, and other energy infrastructures, and attacks and disruptions, both physical, cyber, and hybrid targeting physical and cyber assets, are becoming increasingly sophisticated and dynamic. Several U.S. government agencies have warned of increased risks related to physical attacks, ransomware attacks and cybersecurity threats related to the energy sector and its supply chains, and that the risks may escalate during periods of heightened geopolitical tensions. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks. 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. The Registrants' reliance on vendors to provide services and equipment, and its shared information systems with Constellation pursuant to the Transition Services Agreement between Exelon and Constellation, increases the risk to assets, systems, and data. While 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. The risk of these events and security breaches occurring continues to intensify. The Registrants have been, and will likely continue to be, subjected to physical and cyber-attacks. While to date none of the Registrants has directly experienced a material breach or material disruption to its network or information systems or operations, as such attacks continue to increase in sophistication and frequency, the Registrants may be subject to a material breach or material disruption in the future.

If a significant 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, increased costs including for infrastructure repairs, or operations shutdown, all of which could materially affect the Registrants' financial condition and materially damage its 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 disruptions to business that could result. The continued increase in Federal and state regulatory requirements related to cybersecurity and evolving threat actor-capabilities could require changes to current measures taken by the Registrants or to their business operations and could adversely affect their consolidated financial statements.

The Registrants’ employees, contractors, customers, and the general public could be exposed to a risk of injury due to the nature of the energy industry (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 are at some risk for serious injury, including loss of life. These risks include gas explosions, pole strikes, and electric contact cases.

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 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, or operational accidents such as wildfires or natural gas explosions which could result in increased costs, including supply chain costs and third-party property damage. An extreme weather event, natural disaster, 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 impact that potential terrorist attacks could have on the industry and the Registrants is uncertain. The Registrants face a risk that their operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect Registrants' operations in unpredictable ways, such as changes in insurance markets and disruptions of supplies and markets. 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, 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, 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, on behalf of the Registrants Exelon maintains a level of insurance coverage consistent with industry practices against property, casualty, and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

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 lack of availability of labor, materials or parts, 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, could materially impact the timing and execution of capital projects, as well as other aspects of the Registrants' businesses. 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.

The Utility Registrants' respective ability to deliver electricity, their operating costs, and their capital expenditures could be negatively impacted by 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.

PJMs 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.

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

Certain events, such as the separation transaction, an employee strike, loss of employees, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for the Registrants. Such challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. As a result of such events, costs, including costs for contractors to replace employees, productivity costs, and safety costs, could rise. 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 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 the Separation (Exelon)

In connection with the separation into two public companies, Exelon and Constellation have agreed to indemnify each other for certain liabilities. If Exelon is required to pay under these indemnities to Constellation, Exelon's financial results could be negatively impacted. The Constellation indemnities may not be sufficient to hold Exelon harmless from the full amount of liabilities for which Constellation has been allocated responsibility, and Constellation may not be able to satisfy its indemnification obligations in the future.

Pursuant to the separation agreement and certain other agreements between Exelon and Constellation, each party agreed to indemnify the other for certain liabilities, generally for uncapped amounts. Liabilities subject to Exelon's indemnity obligations to Constellation generally are not subject to caps, may be significant and could negatively impact Exelon's business. Any amounts Exelon is required to pay pursuant to these indemnity obligations could require Exelon to divert cash that would otherwise have been used in furtherance of its operating business. Further, third parties could seek to hold Exelon responsible for any of the liabilities that Constellation has agreed to retain and for which Constellation is obligated to indemnify Exelon. The indemnities from Constellation for Exelon's benefit may not be sufficient to protect Exelon against the full amount of such liabilities, and Constellation may not be able to fully satisfy its indemnification obligations. Even if Exelon ultimately succeeds in recovering from Constellation any amounts for which Exelon is held liable, Exelon may be temporarily required to bear these losses. Each of these risks could negatively affect Exelon's business, results of operations and financial condition.

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, develop and deploy new technologies, 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 Exelon Board of Directors is responsible for oversight of risks from cybersecurity threats. As part of its responsibility and as documented in the 2022 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 Board of Directors engages with the CISO and a cross-functional management team regarding the risks from cybersecurity threats. The CISO and professionals from the legal and compliance departments brief the Board of Directors 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 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 25 years of information technology and cybersecurity experience in the critical infrastructure sector, of which 23 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 at December 31, 2023 were as follows:

Voltage	Circuit Miles					
(Volts)	ComEd	PECO	BGE	Pepco	DPL	ACE
765,000	90	—	—	—	—	—
500,000[(a)]	—	188	216	108	16	—
345,000	2,678	—	—	—	—	—
230,000	—	550	352	782	472	258
138,000	2,268	135	55	61	587	214
115,000	—	—	700	25	—	—
69,000	—	177	—	—	568	664

(a) In addition, PECO, DPL, and ACE have an ownership interest located in Delaware and New Jersey. See Note 8 — 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:

Circuit Miles	ComEd	PECO	BGE	Pepco	DPL	ACE
Overhead	35,366	12,983	9,151	4,174	6,019	7,343
Underground	32,818	9,676	18,071	7,358	6,589	3,033

Gas

The following table presents PECO's, BGE's, and DPL's natural gas pipeline miles at December 31, 2023:

	PECO	BGE	DPL
Transmission[(a)]	6	149	8
Distribution	7,305	7,562	2,209
Service piping	6,494	6,497	1,492
Total	13,805	14,208	3,709

(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:

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	25

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 16 — 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 3 — Regulatory Matters and Note 18 — 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)

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, 2024, there were 999,538,542 shares of Common stock outstanding and approximately 76,661 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 2019 through 2023. 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, 2018 in Exelon Common stock, the S&P 500 Stock Index, and the S&P Utility Index; and
- All dividends are reinvested.

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Value of Investment at December 31,						
	2018	2019	2020	2021	2022	2023
Exelon Corporation	$100.00	$104.28	$100.22	$141.73	$153.53	$132.08
S&P 500	$100.00	$131.49	$155.68	$200.37	$164.08	$207.21
S&P Utilities	$100.00	$126.35	$126.96	$149.39	$151.73	$140.99

ComEd

As of January 31, 2024, there were 127,021,399 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, 2024, in addition to Exelon, there were 281 record holders of ComEd Common stock. There is no established market for shares of the Common stock of ComEd.

PECO

As of January 31, 2024, 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, 2024, 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, 2024, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2024, 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, 2024, 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, 2024, 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 2024. The 2024 quarterly dividend will be $0.38 per share.

As of December 31, 2023, Exelon had Retained earnings of $5,490 million, ComEd had Retained earnings of $2,374 million, PECO had Retained earnings of $2,019 million, BGE had Retained earnings of $2,244 million, and PHI had Undistributed losses of $275 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2023 and 2022:

	2023				2022			
(per share)	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Exelon	$ 0.3600	$ 0.3600	$ 0.3600	$ 0.3600	$ 0.3375	$ 0.3375	$ 0.3375	$ 0.3375

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:

	2023				2022			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
ComEd	$ 187	$ 185	$ 187	$ 187	$ 144	$ 145	$ 145	$ 144
PECO	102	101	101	101	100	99	100	100
BGE	78	79	79	80	74	75	75	76
PHI	103	198	100	112	125	230	293	102
Pepco	52	85	67	48	63	100	258	42
DPL	36	37	18	42	48	39	15	41
ACE	15	75	15	21	17	90	19	19

First Quarter 2024 Dividend

On February 21, 2024, Exelon's Board of Directors declared a regular quarterly dividend of $0.38 per share on Exelon’s Common stock for the first quarter of 2024. The dividend is payable on Friday, March 15, 2024, to shareholders of record of Exelon as of 5 p.m. Eastern time on Monday, March 4, 2024.

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 5 — 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, 2022 compared to the year ended December 31, 2021, refer to ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS in the 2022 Form 10-K, which was filed with the SEC on February 14, 2023.

COVID-19. There were no material impacts to the Registrants from unfavorable economic conditions due to COVID-19 for the years ended December 31, 2023 and 2022, other than the 2022 impairment discussed below.

The Registrants assessed long-lived assets, goodwill, and investments for recoverability. Exelon and BGE recorded a pre-tax impairment charge of $48 million in 2022 as a result of COVID-19 impacts on office use. See Note 11 — Asset Impairments for additional information related to this impairment assessment.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net income attributable to common shareholders from continuing operations by Registrant for the year ended December 31, 2023 compared to the same period in 2022. For additional information regarding the financial results for the years ended December 31, 2023 and 2022, see the discussions of Results of Operations by Registrant.

	2023	2022	Favorable (Unfavorable) Variance
Exelon	$ 2,328	$ 2,054	$ 274
ComEd	1,090	917	173
PECO	563	576	(13)
BGE	485	380	105
PHI	590	608	(18)
Pepco	306	305	1
DPL	177	169	8
ACE	120	148	(28)
Other[(a)]	(400)	(427)	27

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

The separation of Constellation, including Generation and its subsidiaries, met the criteria for discontinued operations and as such, Generation's results of operations are presented as discontinued operations and have been excluded from Exelon's continuing operations for the year ended December 31, 2022 presented in the table above. See Note 1 — Significant Accounting Policies and Note 2 — Discontinued Operations for additional information.

Accounting rules require certain BSC costs previously allocated to Generation to be presented as part of Exelon's continuing operations as these costs do not qualify as expenses of the discontinued operations. Such costs are included in Other in the table above and were $28 million on a pre-tax basis, for the year ended December 31, 2022. There were no such costs included in Exelon's continuing operations for the year ended December 31, 2023

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income attributable to common shareholders from continuing operations** increased by $274 million and Diluted earnings per average common share from continuing operations increased to $2.34 in 2023 from $2.08 in 2022 primarily due to:

- Higher electric distribution and transmission earnings from higher allowed ROE due to an increase in treasury rates and higher rate base at ComEd;
- Favorable impacts of rate increases at PECO, BGE, and PHI;
- Favorable impacts of the multi-year plans including the recognition of the reconciliation in 2023 at BGE;
- Higher carrying costs related to the CMC regulatory assets at ComEd; and
- Lower BSC costs presented in Exelon's continuing operations, which were previously allocated to Generation but do not qualify as expenses of the discontinued operation per the accounting rules.

The increases were partially offset by:

- Higher interest expense at PECO, BGE, PHI, and Exelon Corporate;
- Unfavorable weather at PECO and PHI;
- Higher depreciation expense at PECO, BGE, and PHI;
- Higher contracting costs at PHI;
- Higher storm costs at PECO and BGE; and
- Higher realized losses from hedging activity 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 from continuing operations as determined in accordance with GAAP and Adjusted (non-GAAP) operating earnings for the year ended December 31, 2023 compared to 2022:

	2023		2022	
(In millions, except per share data)		Earnings per Diluted Share		Earnings per Diluted Share
Net income attributable to common shareholders from continuing operations	**$ 2,328**	**$ 2.34**	**$ 2,054**	**$ 2.08**
Mark-to-market impact of economic hedging activities (net of taxes of $1 and $1, respectively)	(4)	—	4	—
Change in environmental liabilities (net of taxes of $8)	29	0.03	—	—
ERP system implementation costs (net of taxes of $0)[(a)]	—	—	1	—
Asset retirement obligations (net of taxes of $1 and $2, respectively)	(1)	—	(4)	—
SEC matter loss contingency (net of taxes of $0)	46	0.05	—	—
Asset impairments (net of taxes of $10)[(b)]	—	—	38	0.04
Separation costs (net of taxes of $7 and $10, respectively)[(c)]	22	0.02	24	0.02
Change in FERC audit liability (net of taxes of $4)	11	0.01	—	—
Income tax-related adjustments (entire amount represents tax expense)[(d)]	(54)	(0.05)	122	0.12
Adjusted (non-GAAP) operating earnings	**$ 2,377**	**$ 2.38**	**$ 2,239**	**$ 2.27**

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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 2023 and 2022 ranged from 24.0% to 29.0%.

(a) Reflects costs related to a multi-year ERP system implementation, which are recorded in Operating and maintenance expense.
(b) Reflects costs related to the impairment of an office building at BGE, which are recorded in Operating and maintenance expense.
(c) Represents costs related to the separation primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation, and employee-related severance costs, which are recorded in Operating and maintenance expense and Other, net.
(d) In 2022, for PECO, primarily reflects an adjustment to exclude one-time non-cash impacts associated with the remeasurement of deferred income taxes as a result of the reduction in Pennsylvania corporate income tax rate. For Corporate, in connection with the separation, Exelon recorded an income tax expense primarily due to the long-term marginal state income tax rate change, the recognition of valuation allowances against the net deferred tax assets positions for certain standalone state filing jurisdictions, and nondeductible transaction costs partially offset by a one-time impact associated with a state tax benefit. In 2023, reflects the adjustment to state deferred income taxes due to changes in forecasted apportionment.

Significant 2023 Transactions and Developments

Separation

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies ("the separation"). Exelon completed the separation on February 1, 2022. Constellation was newly formed and incorporated in Pennsylvania on June 15, 2021 for the purpose of separation and holds Generation. The separation represented a strategic shift that would have a major effect on Exelon's operations and financial results. Accordingly, the separation meets the criteria for discontinued operations. See Note 2 — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for additional information on the separation and discontinued operations.

In connection with the separation, Exelon incurred separation costs impacting continuing operations of $29 million and $34 million on a pre-tax basis for the year ended December 31, 2023 and 2022, respectively, which are recorded in Operating and maintenance expense. These costs are excluded from Adjusted (non-GAAP) Operating Earnings. The separation costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the separation, and employee-related severance costs.

At-the-Market Program

In November and December 2023, Exelon issued approximately 3.6 million shares of Common stock at an average gross price of $39.58 per share. The net proceeds from these issuances were $140 million, which were used for general corporate purposes. See Note 19 — 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 2023. See Note 3 — 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	April 15, 2022	Electric	$ 199	$ 199	7.85%	November 17, 2022	January 1, 2023
	January 17, 2023	Electric	$ 1,487	$ 501	8.905%	December 14, 2023	January 1, 2024
	April 21, 2023	Electric	$ 247	$ 259	8.91%	November 30, 2023	January 1, 2024
PECO - Pennsylvania	March 31, 2022	Natural Gas	$ 82	$ 55	N/A	October 27, 2022	January 1, 2023
BGE - Maryland	May 15, 2020 (amended September 11, 2020)	Electric	$ 203	$ 140	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	$ 108	$ 74	9.65 %		
	February 17, 2023	Electric	$ 313	$ 179	9.50%	December 14, 2023	January 1, 2024
		Natural Gas	$ 289	$ 229	9.45%		
Pepco - Maryland	October 26, 2020 (amended March 31, 2021)	Electric	$ 104	$ 52	9.55 %	June 28, 2021	June 28, 2021
DPL - Maryland	May 19, 2022	Electric	$ 38	$ 29	9.60 %	December 14, 2022	January 1, 2023
ACE - New Jersey	February 15, 2023 (amended August 21, 2023)	Electric	$ 92	$ 45	9.60 %	November 17, 2023	December 1, 2023

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
Pepco - District of Columbia	April 13, 2023	Electric	$ 191	10.50%	Third quarter of 2024
Pepco - Maryland	May 16, 2023 (amended January 26, 2024)	Electric	$ 188	10.50%	Second quarter of 2024
DPL - Delaware	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	10.50%	Second quarter of 2024

Transmission Formula Rates

The following total increases/(decreases) were included in the Utility Registrants' 2023 annual electric transmission formula rate updates. All rates are effective June 1, 2023 to May 31, 2024, subject to review by interested parties pursuant to review protocols of each Utility Registrants' tariff. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase	Annual Reconciliation Increase (Decrease)	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
ComEd	$ 20	$ 63	$ 83	8.09 %	11.50 %
PECO	$ 24	$ 23	$ 47	7.41 %	10.35 %
BGE	$ 19	$ (12)	$ 4	7.34 %	10.50 %
Pepco	$ 37	$ (5)	$ 32	7.57 %	10.50 %
DPL	$ 32	$ (3)	$ 29	7.08 %	10.50 %
ACE	$ 41	$ (12)	$ 29	7.08 %	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 extends back to January 1, 2017. During the first quarter of 2023, ComEd was provided with information from FERC about several potential findings, including ComEd's methodology regarding the allocation of certain overhead costs to capital under FERC regulations. Based on the preliminary findings and discussions with FERC staff, ComEd determined that a loss was probable and recorded a regulatory liability to reflect its best estimate of that loss in the first quarter of 2023.

On July 27, 2023, FERC issued 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 August 28, 2023, ComEd filed a formal notice of the issues it will contest. On December 14, 2023, FERC appointed a settlement judge for the contested overhead allocation findings. The final outcome and resolution of any contested audit issues as well as a reasonable estimate of potential future losses cannot be accurately estimated at this stage; however, the final resolution of these matters could result in recognition of future losses, above the amounts currently accrued, that could be material to the Exelon and ComEd financial statements.

ACE Employee Strike

ACE's collective bargaining agreement with the International Brotherhood of Electrical Workers (IBEW) Local 210, expired on November 2, 2023. On November 5, 2023, IBEW Local 210 initiated a strike in ACE's service territory. While the work stoppage did not result in a disruption in service to customers, Exelon, PHI, and ACE incurred unfavorable impacts to Net income of approximately $31 million, $31 million, and $32 million for the year ended December 31, 2023. On December 5, 2023, IBEW Local 210 ratified a new collective bargaining agreement with ACE and ceased the work stoppage.

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 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these regulatory proceedings.

Legislative and Regulatory Developments

Infrastructure Investment and Jobs Act

On November 15, 2021, President Biden signed the $1.2 trillion IIJA 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. Federal agencies are developing guidelines to implement spending programs under IIJA. The time needed to develop these guidelines will vary with some limited program applications opened as early as the first quarter of 2022. 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.

In September 2022, ComEd and BGE applied for the MMG, which establishes and funds construction, improvement, or acquisition of middle mile broadband infrastructure which creates high-speed internet services. The MMG addresses inequitable broadband access by expansion and extension of the middle mile infrastructure in underserved communities. In June 2023, the National Telecommunications and Information Administration (NTIA) announced it selected two of the applications submitted by BGE and ComEd; awarding ComEd and BGE $14.5 million and $15.4 million respectively. The applications selected by NTIA for BGE and ComEd proposed projects designed to enhance electric grid reliability and resiliency while leading and advancing shared local, state, and national goals to increase broadband connectivity, redundancy, affordability, and equity.

In March 2023, Exelon, ComEd, and PHI submitted three applications related to the Smart Grid Grants program under section 40107 of IIJA. These applications are focused on replacing existing Advanced Distribution Management Systems (ADMS) in support of distributed energy resources (DERs) and grid-edged technologies, strengthening interoperability and data architecture of systems in support of two-way power flows and accelerating advanced metering deployment in disadvantaged communities. In October 2023, ComEd's project, Deployment of a Community-Oriented Interoperable Control Framework for Aggregating and Integrating Distributed Energy Resources and Other Grid-Edge Devices, was recommended by the Grid Deployment Office (GDO) for negotiation of a final award up to $50 million. This project will enable ComEd and its local partners to deploy the next generation of grid technologies that support the growth of solar and electric vehicles (EVs), while piloting new local workforce training initiatives to support job creation connected to the clean energy transition. The GDO has indicated the award negotiation process can take approximately 120 days.

In April 2023, ComEd, PECO, BGE, and PHI submitted seven applications related to the Grid Resilience Grants program under section 40101(c) of IIJA. These applications are broadly focused on improving grid resilience with an emphasis on disadvantaged communities, relief of capacity constraints and modernizing infrastructure, deployment of DER and microgrid technologies and providing improved resilience through storm hardening projects. In October 2023, PECO's project, Creating a Resilient, Equitable, and Accessible Transformation in Energy for Greater Philadelphia (CREATE), was recommended by the GDO for negotiation of a final award up to $100 million. This project will support critical electric infrastructure investments to help reduce the impact of extreme weather and historic flooding on the Registrants' electric distribution system. The GDO has indicated the award negotiation process can take approximately 120 days.

The Registrants are supporting three different Regional Clean Hydrogen Hub opportunities, covering all five states that Exelon operates in plus Washington D.C. under a program that will create networks of hydrogen producers, consumers, and local connective infrastructure to accelerate the use of hydrogen as a clean energy carrier that can deliver or store energy. Applications for the three opportunities under this program were submitted in April 2023. In October 2023 the DOE announced it selected two of the projects for further negotiation: (1) the Mid-Atlantic Clean Hydrogen Hub (MACH2), which is being supported by PECO and PHI, and (2) the Midwest Alliance for Clean Hydrogen (MachH2), which is being supported by ComEd.

In November 2023, the GDO announced up to $3.9 billion available through the second-round funding opportunity of the Grid Resilience and Innovation Partnerships (GRIP) Program for Fiscal Years 2024 and 2025. This funding opportunity focuses on projects that will improve electric transmission by increasing funding and advancing interconnection processes for faster build out of energy projects, create comprehensive solutions that link grid communications systems and operations to increase resilience and reduce power outages and threats, and deploy advanced technologies such as distributed energy resources and battery systems to provide essential grid services to ensure American communities across the country have access to affordable, reliable, clean electricity. Exelon, ComEd, BGE, PHI, Pepco, DPL, and ACE submitted seven concept papers in response to the second round of the GRIP program. The concept papers are focused on improving the resilience of the electric grid and deployment of technologies to enhance grid flexibility and deliver benefits to customers and communities across the Exelon footprint. The GDO is expected to issue notifications of encouragement/discouragement for full applications in the first quarter of 2024. Exelon cannot predict if their concept papers will receive a notification of encouragement to submit a full application.

PJM Regional Transmission Expansion

On April 6, 2023, PJM received a deactivation notice for Brandon Shores, a 1,282 MW coal generation plant located in BGE service territory. The deactivation was requested for June 1, 2025 and will result in numerous reliability issues across the region. In June 2023, PJM assigned a portion of transmission system upgrades to mitigate these reliability impacts to PECO, BGE, and Pepco. In July 2023, PJM Board of Managers approved assigning Exelon transmission system upgrades to mitigate these reliability impacts to PECO, BGE, and Pepco. The initial projected capital expenditures associated with these upgrades are approximately $80 million, $650 million, and $80 million for PECO, BGE, and Pepco, respectively. These amounts include a scope reduction estimated by PJM for PECO of $60 million associated with a transmission proposal window, as disclosed at a Transmission Expansion Advisory Committee meeting on October 31, 2023. The upgrades are expected to be completed by the end of 2028.

Separately, PJM held a competitive transmission proposal window from February 24, 2023 through May 31, 2023 to address reliability issues driven by significant load increases in northern Virginia. PECO, BGE, and Pepco submitted four solution proposals. At a meeting of the Transmission Expansion Advisory Committee on October 31, 2023, PJM recommended that PECO, BGE, Pepco, and DPL be awarded a portion of the work for the proposed solution. Initial estimated costs for these upgrades are approximately $70 million, $700 million, $80 million, and $5 million for PECO, BGE, Pepco, and DPL, respectively. The PJM Board of Managers approved the solution in December 2023 and the upgrades are expected to be completed by the end of 2030.

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.

Goodwill (Exelon, ComEd, and PHI)

As of December 31, 2023, 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 5 — 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 12 — 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 2023 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 12 — 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 3 — Regulatory Matters and Note 12 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

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 3 — 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.

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 real estate, private equity, 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 expectation 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 non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and OPEB obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and OPEB plans. The discount rate is the single level rate that produces the same result as the spot rate curve. 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 2023 cost:						
Discount rate[a]	5.53%	5.51%	0.5%	$ (17)	$ (2)	$ (19)
	5.53%	5.51%	(0.5)%	$ 21	$ 2	$ 23
EROA	7.00%	6.50%	0.5%	$ (54)	$ (6)	$ (60)
	7.00%	6.50%	(0.5)%	$ 54	$ 6	$ 60
Change in benefit obligation at December 31, 2023:						
Discount rate[a]	5.19%	5.17%	0.5%	$ (449)	$ (82)	$ (531)
	5.19%	5.17%	(0.5)%	$ 513	$ 92	$ 605

(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 14 — 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.

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, 2023:

(In millions)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Gain (loss)	$ 1,920	$ 3,555	$ (514)	$ (156)	$ (949)	$ (203)	$ 143	$ (462)
Charge against OCI[a]	(2,868)	—	—	—	—	—	—	—

(a) Exelon's charge against OCI (before taxes) consists of up to $2.1 billion, $355 million, $485 million, $298 million, $122 million, and $22 million related to ComEd's, BGE's, PHI's, Pepco's, DPL's, and ACE's respective portions of the deferred costs associated with Exelon's pension and OPEB plans. Exelon also has a net regulatory liability of $102 million (before taxes) related to PECO's portion of the deferred costs associated with Exelon's OPEB plans that would result in an increase in OCI if reversed.

See Note 3 — 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 and energy efficiency formula rates for ComEd, and FERC transmission formula rate tariffs for the Utility Registrants.

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 15 — 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 15 — 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 as well as potential fluctuations in Electric operating revenues at the corporate level in consolidation, which are directly correlated to yields on U.S. Treasury bonds under ComEd's distribution formula rate. 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 17 — Fair Value of Financial Assets and Liabilities and Note 15 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

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 13 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Accounting for Loss Contingencies (All Registrants)

In the preparation of their 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 18 — 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.

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, which include the Registrants' formula rate mechanisms and revenue decoupling mechanisms, 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 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 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Allowance for Credit Losses on Customer Accounts Receivable (All Registrants)

The Registrants estimate the allowance for credit losses on customer receivables by applying loss rates developed specifically for each company based on historical loss experience, current conditions, and forward-looking risk factors to the outstanding receivable balance by customer risk segment. 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. Loss rates applied to the accounts receivable balances are based on a historical average of charge-offs as a percentage of accounts receivable in each risk segment. 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.

Results of Operations by Registrant

Results of Operations—ComEd

	2023	2022	Favorable (Unfavorable) Variance
Operating revenues	$ 7,844	$ 5,761	$ 2,083
Operating expenses			
Purchased power	2,816	1,109	(1,707)
Operating and maintenance	1,450	1,412	(38)
Depreciation and amortization	1,403	1,323	(80)
Taxes other than income taxes	369	374	5
Total operating expenses	6,038	4,218	(1,820)
Gain on sales of assets	—	(2)	2
Operating income	1,806	1,541	265
Other income and (deductions)			
Interest expense, net	(477)	(414)	(63)
Other, net	75	54	21
Total other income and (deductions)	(402)	(360)	(42)
Income before income taxes	1,404	1,181	223
Income taxes	314	264	(50)
Net income	$ 1,090	$ 917	$ 173

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income** increased by $173 million primarily due to increases in electric distribution formula rate earnings (reflecting higher allowed ROE due to an increase in U.S. Treasury rates and the impacts of higher rate base) and carrying costs related to CMC regulatory assets.

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

	2023 vs. 2022 Increase
Distribution	$ 384
Transmission	11
Energy efficiency	64
Other	7
	466
Regulatory required programs	1,617
Total increase	$ 2,083

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

Distribution Revenue. EIMA and FEJA provide for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. 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, 2023, compared to the same period in 2022, due to higher allowed ROE due to an increase in U.S. Treasury rates, the impact of a higher rate base, and higher fully recoverable costs.

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. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenues increased during the year ended December 31, 2023, compared to the same period in 2022, primarily due to the impact of a higher rate base and higher fully recoverable costs.

Energy Efficiency Revenue. FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under FEJA, 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, 2023, compared to the same period in 2022, primarily due to the impact of a higher rate base, and increased regulatory asset amortization, which is fully recoverable.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. Other revenue increased for the year ended December 31, 2023, compared to the same period in 2022, which primarily reflects 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. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding CMCs. ETAC is a retail customer surcharge collected by electric utilities operating in Illinois established by CEJA 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. 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The increase of $1,707 million for the year ended December 31, 2023, compared to the same period in 2022, in **Purchased power expense** is primarily due to the CMCs from the participating nuclear-powered generating facilities, which is offset by an increase in Operating revenues as part of regulatory required programs. See Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding CMCs.

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

	2023 vs. 2022 Increase (Decrease)
BSC costs	$ 36
Labor, other benefits, contracting, and materials	35
Storm-related costs	(10)
Pension and non-pension postretirement benefits expense	(13)
Other	53
	101
Regulatory required programs[a]	(63)
Total increase	$ 38

(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:

	2023 vs. 2022 Increase
Depreciation and amortization[a]	$ 64
Regulatory asset amortization[b]	16
Total increase	$ 80

(a) Reflects ongoing capital expenditures and higher depreciation rates effective January 2023.
(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Interest expense, net increased $63 million for the year ended December 31, 2023, compared to the same period in 2022, primarily due to an increase in interest rates and the issuance of debt in 2022 and 2023.

Effective income tax rates were 22.4% and 22.4% for the years ended December 31, 2023 and 2022, respectively. See Note 13 — 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

	2023	2022	(Unfavorable) Favorable Variance
Operating revenues	$ 3,894	$ 3,903	$ (9)
Operating expenses			
Purchased power and fuel	1,544	1,535	(9)
Operating and maintenance	1,003	992	(11)
Depreciation and amortization	397	373	(24)
Taxes other than income taxes	202	202	—
Total operating expenses	3,146	3,102	(44)
Operating income	748	801	(53)
Other income and (deductions)			
Interest expense, net	(201)	(177)	(24)
Other, net	36	31	5
Total other income and (deductions)	(165)	(146)	(19)
Income before income taxes	583	655	(72)
Income taxes	20	79	59
Net income	$ 563	$ 576	$ (13)

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income** decreased by $13 million, primarily due to unfavorable weather and increases in depreciation and amortization expense and interest expense, partially offset by an increase in gas distribution rates and Pennsylvania corporate income tax legislation passed in July 2022 driving a one-time non-cash decrease to net income for 2022.

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

	2023 vs. 2022		
	(Decrease) Increase		
	Electric	Gas	Total
Weather	$ (103)	$ (37)	$ (140)
Volume	1	1	2
Pricing	31	52	83
Transmission	23	—	23
Other	(3)	6	3
	(51)	22	(29)
Regulatory required programs	88	(68)	20
Total decrease	$ 37	$ (46)	$ (9)

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, 2023 compared to the same period in 2022, Operating revenues related to weather decreased due to the impact of unfavorable 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 years ended December 31, 2023 compared to the same period in 2022 and normal weather consisted of the following:

PECO Service Territory	For the Years Ended December 31, 2023	2022	Normal	% Change 2023 vs. 2022	2023 vs. Normal
Heating Degree-Days	3,587	4,135	4,399	(13.3)%	(18.5)%
Cooling Degree-Days	1,345	1,743	1,440	(22.8)%	(6.6)%

Volume. Electric volume, exclusive of the effects of weather, for the year ended December 31, 2023 compared to the same period in 2022, remained relatively consistent. Natural gas volume for the year ended December 31, 2023 compared to the same period in 2022, remained relatively consistent.

Electric Retail Deliveries to Customers (in GWhs)	2023	2022	% Change	Weather - Normal % Change[b]
Residential	13,262	14,379	(7.8)%	0.5 %
Small commercial & industrial	7,367	7,701	(4.3)%	(0.3) %
Large commercial & industrial	13,638	14,046	(2.9)%	(0.8) %
Public authorities & electric railroads	606	638	(5.0)%	(5.0) %
Total electric retail deliveries[a]	34,873	36,764	(5.1)%	(0.3) %

(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.

Number of Electric Customers	At December 31, 2023	2022
Residential	1,535,927	1,525,635
Small commercial & industrial	156,248	155,576
Large commercial & industrial	3,127	3,121
Public authorities & electric railroads	10,417	10,393
Total	1,705,719	1,694,725

Natural Gas Deliveries to customers (in mmcf)	2023	2022	% Change	Weather - Normal % Change[b]
Residential	35,842	42,135	(14.9)%	(3.2) %
Small commercial & industrial	21,182	23,449	(9.7)%	(1.7) %
Large commercial & industrial	51	31	64.5 %	2.7 %
Transportation	23,741	25,011	(5.1)%	(2.4) %
Total natural gas deliveries[a]	80,816	90,626	(10.8)%	(2.6) %

(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing electricity 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.

Number of Gas Customers	At December 31, 2023	2022
Residential	507,197	502,944
Small commercial & industrial	45,001	44,957
Large commercial & industrial	9	9
Transportation	627	655
Total	552,834	548,565

Pricing for the year ended December 31, 2023 compared to the same period in 2022 increased primarily due to an increase in gas distribution rates charged to customers, coupled with higher overall effective rates for both electric and gas attributable to decreased usage.

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.

Other Revenue primarily includes revenue related to late payment charges. Other revenues for the year ended December 31, 2023 compared to the same period in 2022, remained relatively consistent.

Regulatory Required Programs represents revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency, PGC, and the GSA. The riders are designed to provide full and current cost recovery as well as 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of $9 million for the year ended December 31, 2023, compared to the same period in 2022, 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:

	2023 vs. 2022 Increase (Decrease)
Storm-related costs	$ 22
BSC costs	15
Pension and non-pension postretirement benefits expense	(3)
Labor, other benefits, contracting, and materials	(2)
Other[(a)]	(31)
	1
Regulatory Required Programs	10
Total increase	$ 11

(a) Due to one-time charitable contributions for the year ended December 31, 2022

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

	2023 vs. 2022 Increase
Depreciation and amortization[(a)]	$ 24
Regulatory asset amortization	—
Total increase	$ 24

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

Interest expense, net increased $24 million for the year ended December 31, 2023, compared to the same period in 2022, primarily due to the issuance of debt in 2022 and 2023 and increases in interest rates.

Effective income tax rates were 3.4% and 12.1% for the years ended December 31, 2023 and 2022, respectively. See Note 13 — 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

	2023	2022	Favorable (Unfavorable) Variance
Operating revenues	$ 4,027	$ 3,895	$ 132
Operating expenses			
Purchased power and fuel	1,531	1,567	36
Operating and maintenance	741	877	136
Depreciation and amortization	654	630	(24)
Taxes other than income taxes	319	302	(17)
Total operating expenses	3,245	3,376	131
Operating income	782	519	263
Other income and (deductions)			
Interest expense, net	(182)	(152)	(30)
Other, net	18	21	(3)
Total other income and (deductions)	(164)	(131)	(33)
Income before income taxes	618	388	230
Income taxes	133	8	(125)
Net income	$ 485	$ 380	$ 105

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income** increased $105 million primarily due to favorable impacts of the multi-year plans including the recognition of the reconciliation in 2023 and an asset impairment in 2022, partially offset by an increase in depreciation expense, interest expense, and increase in income taxes in 2023 as compared to 2022. See Note 11 — Asset Impairments for additional information on the asset impairment and Note 3 — Regulatory Matters for additional information on multi-year plan order.

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

	2023 vs. 2022		
	Increase (Decrease)		
	Electric	Gas	Total
Distribution	$ 78	$ 45	$ 123
Transmission	56	—	56
Other	(1)	2	1
	133	47	180
Regulatory required programs	104	(152)	(48)
Total increase (decrease)	$ 237	$ (105)	$ 132

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 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling for BGE.

	At December 31,	
Number of Electric Customers	2023	2022
Residential	1,211,889	1,204,429
Small commercial & industrial	115,787	115,524
Large commercial & industrial	13,072	12,839
Public authorities & electric railroads	261	266
Total	1,341,009	1,333,058

	At December 31,	
Number of Gas Customers	2023	2022
Residential	657,823	655,373
Small commercial & industrial	37,993	38,207
Large commercial & industrial	6,309	6,233
Total	702,125	699,813

Distribution Revenue increased for the year ended December 31, 2023 compared to the same period in 2022, 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, 2023 compared to the same period in 2022 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 remained relatively consistent for the year ended December 31, 2023 compared to the same period in 2022.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, STRIDE, 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The decrease of $36 million for the year ended December 31, 2023 compared to the same period in 2022 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:

	2023 vs. 2022 Increase (Decrease)
BSC costs	$ 18
Storm-related costs	12
Labor, other benefits, contracting, and materials	12
Pension and non-pension postretirement benefits expense	5
Credit loss expense	(8)
Impairment on long-lived assets[a]	(48)
Multi-year plan reconciliations[b]	(112)
Other	(17)
	(138)
Regulatory required programs	2
Total decrease	$ (136)

(a) See Note 11 — Asset Impairments for additional information on the asset impairment taken in 2022.
(b) See Note 3 — Regulatory Matters for additional information on multi-year plan reconciliations.

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

	2023 vs. 2022 Increase (Decrease)
Depreciation and amortization[a]	$ 30
Regulatory required programs	(5)
Regulatory asset amortization	(1)
Total increase	$ 24

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

Taxes other than income taxes increased by $17 million for the year ended December 31, 2023 compared to the same period in 2022, primarily due to increased property taxes.

Interest expense, net increased $30 million for the year ended December 31, 2023 compared to the same period in 2022, due to the issuance of debt in 2022 and 2023 and increases in interest rates.

Effective income tax rates were 21.5% and 2.1% for the years ended December 31, 2023 and 2022, respectively. The change is primarily due to decreases in the multi-year plans' accelerated income tax benefits in 2023 compared to 2022. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on both the three-year electric and natural gas distribution multi-year plans and Note 13 — 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, 2023 compared to the same period in 2022. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	2023	2022	(Unfavorable) Favorable Variance
PHI	$ 590	$ 608	$ (18)
Pepco	306	305	1
DPL	177	169	8
ACE	120	148	(28)
Other[(a)]	(13)	(14)	1

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

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income** decreased by $18 million primarily due to higher contracting costs as a result of the ACE employee strike, an increase in environmental liabilities at Pepco, an increase in interest expense, depreciation expense, and unfavorable weather at DPL Delaware electric and natural gas service territories, partially offset by higher distribution rates at DPL Delaware, favorable impacts of the Pepco Maryland and DPL Maryland multi-year plans, and higher transmission rates.

Results of Operations—Pepco

	2023	2022	Favorable (Unfavorable) Variance
Operating revenues	$ 2,824	$ 2,531	$ 293
Operating expenses			
Purchased power	974	834	(140)
Operating and maintenance	572	507	(65)
Depreciation and amortization	441	417	(24)
Taxes other than income taxes	390	382	(8)
Total operating expenses	2,377	2,140	(237)
Gain on sales of assets	9	—	9
Operating income	456	391	65
Other income and (deductions)			
Interest expense, net	(165)	(150)	(15)
Other, net	66	55	11
Total other income and (deductions)	(99)	(95)	(4)
Income before income taxes	357	296	61
Income taxes	51	(9)	(60)
Net income	$ 306	$ 305	$ 1

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income** increased by $1 million primarily due to favorable impacts of the Maryland multi-year plan, higher transmission rates, customer growth, and a gain on sale of land in the fourth quarter of 2023, partially offset by an increase in environmental liabilities, depreciation expense, and interest expense.

	2023 vs. 2022 Increase
Distribution	$ 94
Transmission	55
Other	3
	152
Regulatory required programs	141
Total increase	$ 293

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 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 are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on revenue decoupling for Pepco Maryland and District of Columbia.

Number of Electric Customers	At December 31, 2023	2022
Residential	866,018	856,037
Small commercial & industrial	54,142	54,339
Large commercial & industrial	22,941	22,841
Public authorities & electric railroads	208	197
Total	943,309	933,414

Distribution Revenue increased for the year ended December 31, 2023 compared to the same period in 2022, primarily due to higher rates due to the expiration of customer offsets, favorable impacts of the Maryland multi-year plan, and 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 increased for the year ended December 31, 2023 compared to the same period in 2022 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The increase of $140 million for the year ended December 31, 2023 compared to the same period in 2022, 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:

		2023 vs. 2022
		Increase (Decrease)
Labor, other benefits, contracting, and materials[(a)]	$	26
BSC and PHISCO costs		14
Pension and non-pension postretirement benefits expense		11
Credit loss expense		(3)
Storm-related costs		(9)
Other		16
		55
Regulatory required programs		10
Total increase	$	65

(a) Primarily reflects an increase in environmental liabilities for the year ended December 31, 2023.

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

		2023 vs. 2022
		Increase (Decrease)
Depreciation and amortization[(a)]	$	22
Regulatory asset amortization		13
Regulatory required programs		(11)
Total increase	$	24

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

Taxes other than income taxes increased $8 million for the year ended December 31, 2023 compared to the same period in 2022, primarily due to an increase in property taxes.

Interest expense, net increased $15 million for the year ended December 31, 2023 compared to the same period in 2022 primarily due to an increase in interest rates and the issuance of debt in 2022 and 2023.

Gain on sales of assets for the year ended December 31, 2023 compared to the same period in 2022 increased $9 million due to the sale of land in the fourth quarter of 2023.

Other, net increased $11 million for the year ended December 31, 2023 compared to the same period in 2022, primarily due to higher AFUDC equity.

Effective income tax rates were 14.3% and (3.0)% for the years ended December 31, 2023 and 2022, respectively. See Note 13 — 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

	2023	2022	Favorable (Unfavorable) Variance
Operating revenues	$ 1,688	$ 1,595	$ 93
Operating expenses			
Purchased power and fuel	737	706	(31)
Operating and maintenance	364	349	(15)
Depreciation and amortization	244	232	(12)
Taxes other than income taxes	75	72	(3)
Total operating expenses	1,420	1,359	(61)
Operating income	268	236	32
Other income and (deductions)			
Interest expense, net	(74)	(66)	(8)
Other, net	18	13	5
Total other income and (deductions)	(56)	(53)	(3)
Income before income taxes	212	183	29
Income taxes	35	14	(21)
Net income	$ 177	$ 169	$ 8

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022. **Net income** increased by $8 million primarily due to favorable impacts of the Maryland multi-year plan, higher Delaware electric and natural gas distribution rates, and higher transmission rates, partially offset by unfavorable weather conditions in Delaware electric and natural gas service territories, and an increase in depreciation expense and interest expense.

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

	2023 vs. 2022		
	(Decrease) Increase		
	Electric	Gas	Total
Weather	$ (10)	$ (6)	$ (16)
Volume	(6)	(5)	(11)
Distribution	34	7	41
Transmission	42	—	42
Other	5	—	5
	65	(4)	61
Regulatory required programs	61	(29)	32
Total increase	$ 126	$ (33)	$ 93

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in Maryland are not 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 3 — 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, 2023 compared to the same period in 2022, Operating revenues related to weather decreased due to unfavorable 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, 2023 compared to same period in 2022 and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Delaware Electric Service Territory	2023	2022	Normal	2023 vs. 2022	2023 vs. Normal
Heating Degree-Days	3,845	4,428	4,585	(13.2)%	(16.1)%
Cooling Degree-Days	1,275	1,382	1,276	(7.7)%	(0.1)%

	For the Years Ended December 31,			% Change	
Delaware Natural Gas Service Territory	2023	2022	Normal	2023 vs. 2022	2023 vs. Normal
Heating Degree-Days	3,845	4,428	4,662	(13.2)%	(17.5)%

Volume, exclusive of the effects of weather, decreased for the year ended December 31, 2023 compared to the same period in 2022 primarily due to customer usage, partially offset by customer growth.

Electric Retail Deliveries to Delaware Customers (in GWhs)	2023	2022	% Change	Weather - Normal % Change[(b)]
Residential	3,065	3,242	(5.5)%	(1.4)%
Small commercial & industrial	1,399	1,443	(3.0)%	(1.4)%
Large commercial & industrial	3,071	3,162	(2.9)%	(2.0)%
Public authorities & electric railroads	33	33	—%	1.2 %
Total electric retail deliveries[(a)]	7,568	7,880	(4.0)%	(1.6)%

	At December 31,	
Number of Total Electric Customers (Maryland and Delaware)	2023	2022
Residential	485,713	481,688
Small commercial & industrial	64,220	63,738
Large commercial & industrial	1,260	1,235
Public authorities & electric railroads	593	597
Total	551,786	547,258

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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)	2023	2022	% Change	Weather - Normal % Change[(b)]
Residential	7,326	8,709	(15.9)%	(6.4)%
Small commercial & industrial	3,660	4,176	(12.4)%	(2.1)%
Large commercial & industrial	1,588	1,697	(6.4)%	(6.4)%
Transportation	6,004	6,696	(10.3)%	(7.1)%
Total natural gas deliveries[(a)]	18,578	21,278	(12.7)%	(5.7)%

Number of Delaware Natural Gas Customers	At December 31, 2023	At December 31, 2022
Residential	129,903	129,502
Small commercial & industrial	10,133	10,144
Large commercial & industrial	14	17
Transportation	163	156
Total	140,213	139,819

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(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, 2023 compared to the same period in 2022 primarily due favorable impacts of the Maryland multi-year plan that became effective January 2023, favorable impacts of the higher electric distribution rates in Delaware that became effective July 2023, and higher natural gas distribution rates effective in August 2022.

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, 2023 compared to the same period in 2022 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 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

The increase of $31 million for the year ended December 31, 2023 compared to the same period in 2022, 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:

	2023 vs. 2022 Increase (Decrease)
Pension and non-pension postretirement benefits expense	$ 6
Storm-related costs	5
BSC and PHISCO costs	4
Labor, other benefits, contracting, and materials	1
Credit loss expense	(3)
Other	2
Total increase	$ 15

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

	2023 vs. 2022 Increase (Decrease)
Depreciation and amortization[(a)]	$ 17
Regulatory asset amortization	(1)
Regulatory required programs	(4)
Total increase	$ 12

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(a) For the year ended December 31, 2023, reflects ongoing capital expenditures, higher distribution depreciation rates in Maryland effective March 2022, and higher transmission depreciation rates effective September 2022.

Interest expense, net increased $8 million for the year ended December 31, 2023 compared to the same period in 2022 primarily due to the issuance of debt in 2022 and 2023.

Other, net increased $5 million for the year ended December 31, 2023 compared to the same period in 2022, primarily due to higher AFUDC equity.

Effective income tax rates were 16.5% and 7.7% for the years ended December 31, 2023 and 2022, respectively. See Note 13 — 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

	2023		2022		Favorable (Unfavorable) Variance	
Operating revenues	$	1,522	$	1,431	$	91
Operating expenses						
Purchased power		637		624		(13)
Operating and maintenance		386		331		(55)
Depreciation and amortization		283		261		(22)
Taxes other than income taxes		8		9		1
Total operating expenses		1,314		1,225		(89)
Operating income		208		206		2
Other income and (deductions)						
Interest expense, net		(72)		(66)		(6)
Other, net		20		11		9
Total other income and (deductions)		(52)		(55)		3
Income before income taxes		156		151		5
Income taxes		36		3		(33)
Net income	$	120	$	148	$	(28)

***Year Ended December 31, 2023 Compared to Year Ended December 31, 2022*.** **Net income** decreased $28 million primarily due to higher contracting costs primarily due to the ACE employee strike, and an increase in depreciation expense, and interest expense, partially offset by higher transmission rates.

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

	2023 vs. 2022	
	Increase	
Distribution	$	33
Transmission		46
Other		1
		80
Regulatory required programs		11
Total increase	$	91

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in New Jersey are not impacted by abnormal weather or usage per customer as a result of the CIP which became effective, prospectively, in the third quarter of 2021. 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. 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 3 — 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, 2023	2022
Residential	504,919	502,247
Small commercial & industrial	62,646	62,246
Large commercial & industrial	2,909	3,051
Public authorities & electric railroads	727	734
Total	571,201	568,278

Distribution Revenue increased for the year ended December 31, 2023 compared to the same period in 2022 due to higher distribution rates primarily due to the expiration of customer credits related to the TCJA tax benefits.

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, 2023 compared to the same period in 2022 primarily due to increases in capital investment and underlying costs.

Other Revenue includes rental revenue, service connection fees, and mutual assistance revenues.

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 5 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

The increase of $13 million for the year ended December 31, 2023 compared to same period in 2022, 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:

	2023 vs. 2022 Increase (Decrease)
Labor, other benefits, contracting and materials[(a)]	$ 41
BSC and PHISCO costs	9
Pension and non-pension postretirement benefits expense	1
Storm-related costs	1
Credit loss expense	1
Other	3
	56
Regulatory required programs[(b)]	(1)
Total increase	$ 55

(a) Reflects an increase in contracting costs for the year ended December 31, 2023, primarily due to the ACE employee strike.

(b) 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 changes in **Depreciation and amortization expense** consisted of the following:

	2023 vs. 2022
	Increase (Decrease)
Depreciation and amortization[(a)]	$ 23
Regulatory required programs[(b)]	(1)
Total increase	$ 22

(a) Depreciation and amortization increased primarily due to ongoing capital expenditures and higher transmission depreciation rates effective September 2022.
(b) Regulatory required programs decreased primarily due to the regulatory asset amortization of the PPA termination obligation which is fully offset in Operating revenues.

Interest expense, net increased $6 million for the year ended December 31, 2023 compared to the same period in 2022 primarily due to an increase in interest rates and the issuance of debt in 2022 and 2023.

Effective income tax rates were 23.1% and 2.0% for the years ended December 31, 2023 and 2022, respectively. See Note 13 — 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 expenditures requirements are provided by internally generated cash flows from operations, as well as funds from external sources in the capital markets and through bank borrowings. 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 $4.0 billion, as of December 31, 2023. 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 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' debt and credit agreements.

Cash flows related to Generation have not been presented as discontinued operations and are included in the Consolidated Statements of Cash Flows for all periods presented. The Exelon Consolidated Statement of Cash Flows for the year ended December 31, 2023 includes no cash flows from Generation. The Exelon Consolidated Statement of Cash Flows for the year ended December 31, 2022 includes one months of cash flows from Generation. See below for additional reasons for the changes in cash flows.

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 will be recovered through a new 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 asset.

See Note 3 — Regulatory Matters and Note 18 — 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, 2023 and 2022 by Registrant:

Increase (decrease) in cash flows from operating activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	$ 157	$ 173	$ (13)	$ 105	$ (18)	$ 1	$ 8	$ (28)
Adjustments to reconcile net income to cash:								
Non-cash operating activities	(864)	(336)	(116)	(103)	28	34	(16)	5
Option premiums (paid), net	39	—	—	—	—	—	—	—
Collateral (paid) received, net	(1,394)	18	—	(41)	(344)	(49)	(199)	(96)
Income taxes	52	106	106	54	66	79	26	(11)
Pension and non-pension postretirement benefit contributions	487	143	17	49	54	(1)	(3)	4
Regulatory assets and liabilities, net	887	973	14	(132)	75	24	59	(28)
Changes in working capital and other noncurrent assets and liabilities	469	(426)	170	259	193	140	80	(29)
(Decrease) increase in cash flows from operating activities	$ (167)	$ 651	$ 178	$ 191	$ 54	$ 228	$ (45)	$ (183)

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. See above for additional information related to cash flows from Generation. Significant operating cash flow impacts for the Registrants and Generation for the years ended December 31, 2023 and 2022 were as follows:

- See Note 22 —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 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 increased due to rising energy prices. See Note 15 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.
- See Note 13 — 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 funding strategy and incremental contributions made in 2022 in connection with the separation. 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 differs from the recovery period of those costs. Included within the changes is energy efficiency spend for ComEd of $416 million and $394 million for the years ended December 31, 2023 and 2022, respectively. Also included within the changes is energy efficiency and demand response programs spend for BGE, Pepco, DPL, and ACE of $132 million, $70 million, $25 million, and $20 million for the year ended December 31, 2023, respectively, and $113 million, $71 million, $28 million, and $11 million for the year ended December 31, 2022, respectively. PECO had no energy efficiency and demand response programs spend recorded to a regulatory asset for the years ended December 31, 2023 and 2022. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

- **Changes in working capital and other noncurrent assets and liabilities** for the Utility Registrants and Exelon Corporate total $146 million and for Generation total $323 million. The change for Generation primarily relates to the revolving accounts receivable financing arrangement. 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, 2023, the established pricing resulted in ComEd owing payments to nuclear-powered generating facilities, which is reported within the cash flows from operations as a change in Accounts payable and accrued expense.

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, 2023 and 2022 by Registrant:

(Decrease) increase in cash flows from investing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ (261)	$ (70)	$ (77)	$ (105)	$ (279)	$ (83)	$ (132)	$ (62)
Investment in NDT fund sales, net	28	—	—	—	—	—	—	—
Collection of DPP	(169)	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	9	—	—	—	10	10	—	—
Other investing activities	8	(20)	(6)	(4)	2	5	(3)	(1)
(Decrease) increase in cash flows from investing activities	$ (385)	$ (90)	$ (83)	$ (109)	$ (267)	$ (68)	$ (135)	$ (63)

Significant investing cash flow impacts for the Registrants for 2023 and 2022 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 Utility Registrants. See Note 2 — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for Capital expenditures related to Generation prior to the separation.

- **Collection of DPP** relates to Generation's revolving accounts receivable financing agreement which Generation entered into in April 2020.

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, 2023 and 2022 by Registrant:

(Decrease) increase in cash flows from financing activities	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ (2,199)	$ (402)	$ (313)	$ (350)	$ 34	$ (291)	$ (18)	$ 343
Long-term debt, net	(124)	225	100	150	(40)	35	25	(100)
Changes in intercompany money pool	—	—	—	—	(16)	—	—	—
Issuance of common stock	(423)	—	—	—	—	—	—	—
Dividends paid on common stock	(99)	(168)	(6)	(16)	—	211	10	19
Repayments on short-term borrowings with maturities greater than 90 days	1,350	(150)	—	—	—	—	—	—
Distributions to member	—	—	—	—	237	—	—	—
Contributions from parent/member	—	(15)	74	99	(312)	(157)	(48)	(110)
Transfer of cash, restricted cash, and cash equivalents to Constellation	2,594	—	—	—	—	—	—	—
Other financing activities	(7)	(3)	9	4	(19)	(16)	(6)	—
Increase (decrease) in cash flows from financing activities	$ 1,092	$ (513)	$ (136)	$ (113)	$ (116)	$ (218)	$ (37)	$ 152

Significant financing cash flow impacts for the Registrants for 2023 and 2022 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 16 — 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** relates to the August 2022 underwritten public offering of Exelon common stock as well as 2023 issuances under the ATM program. See Note 19 — 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 18 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on dividend restrictions. See below for quarterly dividends declared.
- **Repayments on short-term borrowings,** varies due to debt issuances and redemptions each year. Refer to Note 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on repayments on short-term borrowings for the Registrants.
- Refer to Note 2 — Discontinued Operations for the T**ransfer of cash, restricted cash, and cash equivalents to Constellation** related to the separation.
- **Other financing activities** primarily consists of debt issuance costs. See debt issuances table below for additional information on the Registrants' debt issuances.

Debt Issuances and Redemptions

See Note 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' long-term debt. Debt activity for 2023 and 2022 by Registrant was as follows:

During 2023, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Notes	5.15%	March 15, 2028	$1,000	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	5.30%	March 15, 2033	850	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes	5.60%	March 15, 2053	650	Repay existing indebtedness and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 134	4.90%	February 1, 2033	400	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
ComEd	First Mortgage Bonds Series 135	5.30%	February 1, 2053	575	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
PECO	First and Refunding Mortgage Bonds	4.90%	June 15, 2033	575	Refinance existing indebtedness, refinance outstanding commercial paper obligations, and for general corporate purposes.
BGE	Notes	5.40%	June 1, 2053	700	Repay outstanding commercial paper obligations, repay existing indebtedness, and for general corporate purposes.
Pepco	First Mortgage Bonds	5.35%	September 13, 2033	100	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.30%	March 15, 2033	85	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.40%	March 15, 2038	40	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	5.57%	March 15, 2053	125	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.30%	March 15, 2033	60	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.57%	March 15, 2053	65	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.45%	November 8, 2033	340	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.55%	November 8, 2038	75	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	5.72%	November 8, 2053	110	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	5.57%	March 15, 2053	75	Repay existing indebtedness and for general corporate purposes.

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	SMBC Term Loan Agreement	SOFR plus 0.65%	July 21, 2023[(b)]	$300	Fund a cash payment to Constellation and for general corporate purposes.
Exelon	U.S. Bank Term Loan Agreement	SOFR plus 0.65%	July 21, 2023[(b)]	300	Fund a cash payment to Constellation and for general corporate purposes.
Exelon	PNC Term Loan Agreement	SOFR plus 0.65%	July 24, 2023[(b)]	250	Fund a cash payment to Constellation and for general corporate purposes.
Exelon	Notes[(a)]	2.75%	March 15, 2027	650	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes[(a)]	3.35%	March 15, 2032	650	Repay existing indebtedness and for general corporate purposes.
Exelon	Notes[(a)]	4.10%	March 15, 2052	700	Repay existing indebtedness and for general corporate purposes.
Exelon	Long-Term Software License Agreements	2.30%	December 1, 2025	17	Procurement of software licenses
Exelon	Long-Term Software License Agreements	3.70%	August 9, 2025	8	Procurement of software licenses
Exelon	SMBC Term Loan Agreement	SOFR plus 0.85%	April 7, 2024	500	Repay existing indebtedness and for general corporate purposes.
ComEd	First Mortgage Bonds, Series 132	3.15%	March 15, 2032	300	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
ComEd	First Mortgage Bonds, Series 133	3.85%	March 15, 2052	450	Repay outstanding commercial paper obligations and to fund other general corporate purposes.
PECO	First and Refunding Mortgage Bonds	4.60%	May 15, 2052	350	Refinance existing indebtedness and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	4.375%	August 15, 2052	425	Refinance outstanding commercial paper and for general corporate purposes.
BGE	Notes	4.55%	June 1, 2052	500	Repay outstanding commercial paper obligations, repay existing indebtedness, and for general corporate purposes.
Pepco	First Mortgage Bonds	3.97%	March 24, 2052	400	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	3.35%	September 15, 2032	225	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	3.06%	February 15, 2052	125	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	2.27%	February 15, 2032	25	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	3.06%	February 15, 2052	150	Repay existing indebtedness and for general corporate purposes.

(a) In connection with the issuance and sale of the Notes, Exelon entered into a Registration Rights Agreement with the representatives of the initial purchasers of the Notes and other parties. Pursuant to the Registration Rights Agreement, Exelon filed a registration statement on August 3, 2022, with respect to an offer to exchange the Notes for substantially similar notes of Exelon that are registered under the Securities Act. An exchange offer of registered notes for the Notes was completed on January 12, 2023. The registered notes issued in exchange for Notes in the exchange offer have terms identical in all respects to the Notes, except that their issuance was registered under the Securities Act.

(b) During the third quarter of 2022, the SMBC Term Loan, U.S. Bank Term Loan, and PNC Term Loan were all reclassified to Long-term debt due within one year on the Exelon Consolidated Balance Sheet, given that the Term Loans have maturity dates of July 21, 2023, and July 24, 2023, respectively.

During 2023, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	SMBC Term Loan Agreement	SOFR plus 0.65%	July 21, 2023	$ 300
Exelon	US Bank Term Loan Agreement	SOFR plus 0.65%	July 21, 2023	300
Exelon	PNC Term Loan Agreement	SOFR plus 0.65%	July 24, 2023	250
Exelon	Long-Term Software License Agreement	3.70%	August 9, 2025	6
Exelon	Long-Term Software License Agreement	3.95%	May 1, 2024	2
Exelon	Long-Term Software License Agreement	3.70%	August 9, 2025	1
Exelon	Long-Term Software License Agreement	2.30%	December 1, 2025	4
PECO	Loan Agreement	2.00%	June 20, 2023	50
BGE	Notes	3.35%	July 1, 2023	300
DPL	First Mortgage Bonds	3.50%	November 15, 2023	500

During 2022, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon	Junior Subordinated Notes	3.50%	May 2, 2022	$ 1,150
Exelon	Long-Term Software License Agreement	3.96%	May 1, 2024	2
Exelon	Long-Term Software License Agreement	2.30%	December 1, 2025	4
ComEd	Long-Term Software License Agreement	3.70%	August 9, 2025	1
PECO	First Mortgage Bonds	2.375%	September 15, 2022	350
BGE	Notes	2.80%	August 15, 2022	250
ACE	First Mortgage Bonds	3.05%	April 1, 2022	200
ACE	Tax-Exempt Bonds	1.70%	September 1, 2022	110

Additionally, in connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle an intercompany loan that mirrored the terms and amounts of the third-party debt obligations. The loan agreements were entered into as part of the 2012 Constellation merger. See Note 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the mirror debt.

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, 2023 and for the first quarter of 2024 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2023	February 14, 2023	February 27, 2023	March 10, 2023	$ 0.3600
Second Quarter 2023	April 25, 2023	May 15, 2023	June 9, 2023	$ 0.3600
Third Quarter 2023	July 25, 2023	August 15, 2023	September 8, 2023	$ 0.3600
Fourth Quarter 2023	November 1, 2023	November 15, 2023	December 8, 2023	$ 0.3600
First Quarter 2024	February 21, 2024	March 4, 2024	March 15, 2024	$ 0.3800

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(a) Exelon's Board of Directors approved an updated dividend policy for 2024. The 2024 quarterly dividend will be $0.38 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 continuing operations, public debt offerings, commercial paper markets, and large, diversified credit facilities. The credit facilities include $4.0 billion in aggregate total commitments of which $2.4 billion was available to support additional commercial paper as of December 31, 2023, and of which no financial institution has more than 6% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during 2023 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 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. The Registrants had access to the commercial paper markets and had availability under their revolving credit facilities during 2023 to fund their short-term liquidity needs, when necessary. 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 entered into an agreement with certain underwriters in connection with an underwritten public offering of 12.995 million shares of its Common stock, no par value. The net proceeds were $563 million before expenses paid. Exelon used the proceeds, together with available cash balances, to repay $575 million in borrowings under a $1.15 billion term loan credit facility. See Note 19 — Shareholders' Equity and Note 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

On August 4, 2022, Exelon executed an equity distribution agreement ("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 $1.0 billion. Exelon has no obligation to offer or sell any shares of Common stock under the Equity Distribution Agreement and may at any time suspend or terminate offers and sales under the Equity Distribution Agreement. In November and December 2023, Exelon issued approximately 3.6 million shares of Common stock at an average gross price of $39.58 per share. The net proceeds from these issuances were $140 million, which were used for general corporate purposes. As of December 31, 2023, $858 million of Common stock remained available for sale pursuant to the ATM program.

Pursuant to the Separation Agreement between Exelon and Constellation Energy Corporation, Exelon made a cash payment of $1.75 billion to Generation on January 31, 2022. See Note 2 — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for additional information on the separation.

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, 2023 and available credit facility capacity prior to any incremental collateral at December 31, 2023:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ —	$ —	$ 788
PECO	—	25	435
BGE	—	61	258
Pepco	—	—	168
DPL	—	10	237
ACE	—	—	101

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

Capital Expenditures

As of December 31, 2023, estimates of capital expenditures for plant additions and improvements are as follows:

(in millions)[(a)]	2024 Transmission	2024 Distribution	2024 Gas	Total 2024	Beyond 2024[(b)]
Exelon	N/A	N/A	N/A	$ 7,425	$ 27,100
ComEd [(c)]	550	1,600	N/A	2,150	9,150
PECO	75	1,225	400	1,700	5,650
BGE	475	625	500	1,600	6,075
PHI	550	1,325	100	1,975	6,275
Pepco	200	750	N/A	950	2,925
DPL	200	325	100	600	1,825
ACE	150	275	N/A	425	1,500

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(a) Numbers rounded to the nearest $25M and may not sum due to rounding.
(b) Includes estimated capital expenditures for the Utility Registrants from 2025 to 2027.
(c) Effective in 2024, ComEd has chosen to update its rate of capitalization of certain overhead costs on a prospective basis.

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 $93 million in 2024. 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 2024:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 93	$ 15	$ 47
ComEd	3	1	18
PECO	2	1	1
BGE	17	1	14
PHI	66	8	11
Pepco	—	1	10
DPL	—	—	—
ACE	7	—	—

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 14 — 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, 2023 under existing financial commitments:

Exelon

	2024	Beyond 2024	Total	Time Period
Long-term debt and finance leases[(a)]	$ 1,403	$ 39,876	$ 41,279	2024 - 2053
Interest payments on long-term debt[(b)]	1,659	26,936	28,595	2024 - 2053
Operating leases	49	302	351	2024 - 2099
Fuel purchase agreements[(c)]	281	1,557	1,838	2024 - 2039
Electric supply procurement	3,808	2,222	6,030	2024 - 2027
Long-term renewable energy and REC commitments	366	1,672	2,038	2024 - 2038
Other purchase obligations[(d)]	4,839	3,236	8,075	2024 - 2031
DC PLUG obligation	3	—	3	2024
ZEC commitments	218	421	639	2024 - 2027
Pension contributions[(e)]	93	1,000	1,093	2024 - 2029
Total cash requirements	$ 12,719	$ 77,222	$ 89,941	

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(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, 2023 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, 2023. 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) Represents the future estimated value at December 31, 2023 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants or subsidiary and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(e) These amounts represent Exelon's expected contributions to its qualified pension plans. Qualified pension contributions for years after 2029 are not included.

ComEd

	2024	Beyond 2024	Total	Time Period
Long-term debt[a]	$ 250	$ 11,567	$ 11,817	2024 - 2053
Interest payments on long-term debt[b]	470	8,240	8,710	2024 - 2053
Operating leases	—	—	—	2024 - 2026
Electric supply procurement	417	196	613	2024 - 2026
Long-term renewable energy and REC commitments	336	1,523	1,859	2024 - 2038
Other purchase obligations[c]	1,244	835	2,079	2024 - 2031
ZEC commitments	218	421	639	2024 - 2027
Total cash requirements	$ 2,935	$ 22,782	$ 25,717	

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(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, 2023 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, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

PECO

	2024	Beyond 2024	Total	Time Period
Long-term debt[a]	$ —	$ 5,384	$ 5,384	2024 - 2052
Interest payments on long-term debt[b]	222	4,097	4,319	2024 - 2052
Operating leases	—	—	—	2024 - 2034
Fuel purchase agreements[c]	140	571	711	2024 - 2039
Electric supply procurement	729	183	912	2024 - 2025
Other purchase obligations[d]	785	759	1,544	2024 - 2031
Total cash requirements	$ 1,876	$ 10,994	$ 12,870	

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(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, 2023 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, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

BGE

	2024	Beyond 2024	Total	Time Period
Long-term debt	$ —	$ 4,650	$ 4,650	2024 - 2053
Interest payments on long-term debt[a]	184	3,775	3,959	2024 - 2053
Operating leases	4	34	38	2024 - 2099
Fuel purchase agreements[b]	108	792	900	2024 - 2038
Electric supply procurement	1,097	746	1,843	2024 - 2026
Other purchase obligations[c]	928	433	1,361	2024 - 2029
Total cash requirements	$ 2,321	$ 10,430	$ 12,751	

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2023 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, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

PHI

	2024	Beyond 2024	Total	Time Period
Long-term debt and finance leases	$ 644	$ 7,631	$ 8,275	2024 - 2053
Interest payments on long-term debt[a]	296	4,500	4,796	2024 - 2053
Operating leases	36	164	200	2024 - 2032
Fuel purchase agreements[b]	33	194	227	2024 - 2029
Electric supply procurement	1,565	1,097	2,662	2024 - 2027
Long-term renewable energy and REC commitments	30	149	179	2024 - 2033
Other purchase obligations[c]	1,379	394	1,773	2024 - 2031
DC PLUG obligation	3	—	3	2024
Total cash requirements	$ 3,986	$ 14,129	$ 18,115	

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2023 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, 2023.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.
(c) Represents the future estimated value, as of December 31, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

Pepco

	2024	Beyond 2024	Total	Time Period
Long-term debt and finance leases	$ 405	$ 3,746	$ 4,151	2024 - 2053
Interest payments on long-term debt[(a)]	152	2,809	2,961	2024 - 2053
Operating leases	7	34	41	2024 - 2032
Electric supply procurement	776	574	1,350	2024 - 2027
Other purchase obligations[(b)]	661	231	892	2024 - 2031
DC PLUG obligation	3	—	3	2024
Total cash requirements	$ 2,004	$ 7,394	$ 9,398	

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2023 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.
(b) Represents the future estimated value, as of December 31, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

DPL

	2024	Beyond 2024	Total	Time Period
Long-term debt and finance leases	$ 84	$ 2,012	$ 2,096	2024 - 2053
Interest payments on long-term debt[(a)]	70	1,048	1,118	2024 - 2053
Operating leases	9	46	55	2024 - 2031
Fuel purchase agreements[(b)]	33	194	227	2024 - 2029
Electric supply procurement	445	245	690	2024 - 2026
Long-term renewable energy and REC commitments	30	149	179	2024 - 2033
Other purchase obligations[(c)]	291	81	372	2024 - 2031
Total cash requirements	$ 962	$ 3,775	$ 4,737	

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2023 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, 2023.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity, and services.
(c) Represents the future estimated value, as of December 31, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

ACE

	2024	Beyond 2024	Total	Time Period
Long-term debt and finance leases	$ 154	$ 1,688	$ 1,842	2024 - 2053
Interest payments on long-term debt[a]	60	537	597	2024 - 2053
Operating leases	3	7	10	2024 - 2029
Electric supply procurement	344	278	622	2024 - 2026
Other purchase obligations[b]	386	53	439	2024 - 2028
Total cash requirements	$ 947	$ 2,563	$ 3,510	

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2023 and do not reflect anticipated future refinancing, early redemptions, or debt issuances.

(b) Represents the future estimated value, as of December 31, 2023, 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 not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

See Note 18 — Commitments and Contingencies and Note 3 — 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 16 — Debt and Credit Agreements
Interest payments on long-term debt	Note 16 — Debt and Credit Agreements
Finance leases	Note 10 — Leases
Operating leases	Note 10 — Leases
Long-term renewable energy and REC commitments	Note 3 — Regulatory Matters
ZEC commitments	Note 3 — Regulatory Matters
DC PLUG obligation	Note 3 — Regulatory Matters
Pension contributions	Note 14 — 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 16 — 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, 2023, the capital structures of the Registrants consisted of the following:

	Exelon[(a)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	59 %	43 %	44 %	44 %	42 %	49 %	49 %	48 %
Long-term debt to affiliates[(b)]	1 %	1 %	2 %	— %	— %	— %	— %	— %
Common equity	37 %	54 %	53 %	53 %	— %	49 %	49 %	47 %
Member's equity	— %	— %	— %	— %	56 %	— %	— %	— %
Commercial paper and notes payable	3 %	2 %	1 %	3 %	2 %	2 %	2 %	5 %

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(a) As of December 31, 2022, Exelon's Long-term debt and Common equity capital structure percentages were 57% and 38%, respectively. The change in capital structure percentages above is a result of a decrease in common equity due to the separation of Constellation in addition to an increase in long-term debt issuances. See Note 2 — Discontinued Operations for additional information regarding the separation.

(b) Includes approximately $390 million, $205 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 15 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

The credit ratings for Exelon Corporate, PECO, BGE, PHI, Pepco, DPL, and ACE did not change for the year ended December 31, 2023. On July 26, 2023, S&P raised ComEd's long-term issuer credit rating from 'BBB+' to a 'A-'. S&P also affirmed the current 'A' rating on ComEd's senior secured debt and 'A-2' short-term rating, which influences long and short-term borrowing cost. On December 20, 2023, Moody's revised its outlook on ComEd to negative from stable due to the final order issued by the ICC on December 14, 2023 rejecting ComEd's proposed Grid Plan and establishing retail rates for 2024-2027 as further discussed in Note 3 — Regulatory Matters. At the same time, Moody's affirmed ComEd's current 'A1' senior secured debt rating and its 'P-2' short-term rating.

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, 2023, are presented in the following tables.

	For the Year Ended December 31, 2023		As of December 31, 2023
Exelon Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 510	$ —	$ 225
PECO	305	(238)	—
BSC	—	(350)	(205)
PHI Corporate	—	(65)	(65)
PCI	45	—	45

	For the Year Ended December 31, 2023		As of December 31, 2023
PHI Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Pepco	$ 106	$ (55)	$ —
DPL	147	(2)	—
ACE	—	(147)	—

Shelf Registration Statements

Exelon, ComEd and Pepco have a currently effective combined shelf registration statement that expires in 2025. PECO and BGE plan to file a new combined shelf registration in the first quarter of 2024. DPL and ACE periodically issue securities through the private placement markets. The ability of each Registrant to sell securities off the shelf registration statement or 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, the current financial condition of the Registrant, its 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, 2023					
	Short-term Financing Authority [f]			Remaining Long-term Financing Authority		
	Commission	**Expiration Date**	**Amount**	**Commission**	**Expiration Date**	**Amount**
ComEd[a]	FERC	December 31, 2025	$ 2,500	ICC	January 1, 2025	$ 368
PECO	FERC	December 31, 2025	1,500	PAPUC	December 31, 2024	550
BGE[b]	FERC	December 31, 2025	700	MDPSC	N/A	1,100
Pepco[c]	FERC	December 31, 2025	500	MDPSC / DCPSC	December 31, 2025	1,050
DPL[d]	FERC	December 31, 2025	500	MDPSC / DEPSC	December 31, 2025	550
ACE[e]	NJBPU	December 31, 2025	350	NJBPU	December 31, 2024	625

(a) On June 29, 2023, ComEd filed an application for $2 billion in new money long-term debt financing authority from the ICC, which was approved on December 14, 2023. The finance authority under the approved application has an effective date of January 1, 2024, and extends the expiration date to January 1, 2027.
(b) On December 21, 2022, BGE received approval from the MDPSC for $1.8 billion in new long-term financing authority with an effective date of January 4, 2023.
(c) On June 9, 2022 and June 30, 2022, Pepco received approval from the MDPSC and DCPSC, respectively, for $1.4 billion in new long-term financing authority. The long-term financing authority became effective on the date of respective approvals and has an expiration date of December 31, 2025.

(d) On November 2, 2022, DPL filed with the MDPSC and DEPSC for approval of $1.2 billion in new long-term financing authority with an effective date of December 14, 2022. The financing authority filed with MDPSC does not have an expiration date, while the financing authority filed with DEPSC has an expiration date of December 31, 2025.
(e) On July 14, 2023, ACE filed an application with the NJBPU for renewal of its short-term financing authority through December 31, 2025. ACE received approval on December 20, 2023.
(f) On October 2, 2023, ComEd, PECO, BGE, Pepco, and DPL filed applications with FERC for renewal of their short-term financing authority through December 31, 2025. ComEd, PECO, Pepco, and DPL received approval on December 7, 2023. BGE received approval on December 8, 2023.

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 15 — 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 14 — 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 fixed-rate and variable-rate debt to manage interest rate exposure. See Note 16 — 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, or to lock in rate levels on borrowings, which are typically designated as economic hedges. See Note 15 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.
- Electric operating revenues risk associated with ComEd's distribution formula rate. ComEd's ROE for its electric distribution service through 2023 was directly correlated to yields on U.S. Treasury bonds. Exelon Corporate utilized interest rate derivatives to mitigate volatility and manage risk to Exelon, which were typically accounted for as economic hedges. See Note 15 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information. Beginning January 1, 2024 ComEd's ROE for its electric distribution service will use a fixed rate and no longer be exposed to volatility in yields on U.S. Treasury bonds. See Note 3 — Regulatory Matters 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. 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 3 — Regulatory Matters and Note 15 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

The following table presents maturity and source of fair value for Exelon's and ComEd's mark-to-market commodity contract liabilities. The table provides two fundamental pieces of information. First, the table provides the source of fair value used in determining the carrying amount of 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 17 — 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)]:	2024	2025	2026	2027	2028	2029 and Beyond	Total Fair Value
Prices based on model or other valuation methods (Level 3)	$ (27)	$ (19)	$ (16)	$ (16)	$ (17)	$ (38)	$ (133)

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

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, 2023. 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, 2023, Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2023, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2024

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, 2023. 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, 2023, ComEd's internal control over financial reporting was effective.

February 21, 2024

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, 2023. 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, 2023, PECO's internal control over financial reporting was effective.

February 21, 2024

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, 2023. 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, 2023, BGE's internal control over financial reporting was effective.

February 21, 2024

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, 2023. 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, 2023, PHI's internal control over financial reporting was effective.

February 21, 2024

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, 2023. 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, 2023, Pepco's internal control over financial reporting was effective.

February 21, 2024

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, 2023. 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, 2023, DPL's internal control over financial reporting was effective.

February 21, 2024

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, 2023. 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, 2023, ACE's internal control over financial reporting was effective.

February 21, 2024

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, of Exelon Corporation and its subsidiaries (the "Company") 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), (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2023, 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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 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, 2023, 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 3 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, 2023, there were $10.9 billion of regulatory assets and $10.0 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 21, 2024

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, of Commonwealth Edison Company and its subsidiaries (the "Company") 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 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, 2023, there were $4.1 billion of regulatory assets and $7.7 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 21, 2024

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, of PECO Energy Company and its subsidiaries (the "Company") 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 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, 2023, there were $920 million of regulatory assets and $406 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 21, 2024

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, of Baltimore Gas and Electric Company (the “Company”) 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 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 audit 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 3 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, 2023, there were $956 million of regulatory assets and $800 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 21, 2024

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, of Pepco Holdings LLC and its subsidiaries (the “Company”) 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 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, 2023, there were $1.9 billion of regulatory assets and $1.0 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
Philadelphia, Pennsylvania
February 21, 2024

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, of Potomac Electric Power Company (the "Company") 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 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 audit 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 3 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, 2023, there were $600 million of regulatory assets and $397 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 21, 2024

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, of Delmarva Power & Light Company (the "Company") 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 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 audit 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 3 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, 2023, there were $272 million of regulatory assets and $415 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 21, 2024

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, of Atlantic City Electric Company and its subsidiary (the "Company") 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) (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, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

Critical Audit Matters

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

Accounting for the Effects of Rate Regulation

As described in Notes 1 and 3 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, 2023, there were $608 million of regulatory assets and $146 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 21, 2024

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, 2023	2022	2021
Operating revenues			
Electric operating revenues	$ 19,267	$ 16,899	$ 16,245
Natural gas operating revenues	1,764	2,018	1,522
Revenues from alternative revenue programs	696	161	171
Total operating revenues	21,727	19,078	17,938
Operating expenses			
Purchased power	7,648	5,380	4,703
Purchased fuel	593	834	504
Purchased power and fuel from affiliates	—	159	1,178
Operating and maintenance	4,559	4,673	4,547
Depreciation and amortization	3,506	3,325	3,033
Taxes other than income taxes	1,408	1,390	1,291
Total operating expenses	17,714	15,761	15,256
Gain (loss) on sale of assets and businesses	10	(2)	—
Operating income	4,023	3,315	2,682
Other income and (deductions)			
Interest expense, net	(1,704)	(1,422)	(1,264)
Interest expense to affiliates	(25)	(25)	(25)
Other, net	408	535	261
Total other income and (deductions)	(1,321)	(912)	(1,028)
Income from continuing operations before income taxes	2,702	2,403	1,654
Income taxes	374	349	38
Net income from continuing operations after income taxes	2,328	2,054	1,616
Net income from discontinued operations after income taxes (Note 2)	—	117	213
Net income	2,328	2,171	1,829
Net income attributable to noncontrolling interests	—	1	123
Net income attributable to common shareholders	$ 2,328	$ 2,170	$ 1,706
Amounts attributable to common shareholders:			
Net income from continuing operations	2,328	2,054	1,616
Net income from discontinued operations	—	116	90
Net income attributable to common shareholders	$ 2,328	$ 2,170	$ 1,706
Comprehensive income, net of income taxes			
Net income	$ 2,328	$ 2,171	$ 1,829
Other comprehensive (loss) income, net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefits reclassified to periodic benefit cost	—	(1)	(4)
Actuarial losses reclassified to periodic benefit cost	26	42	223
Pension and non-pension postretirement benefit plans valuation adjustments	(109)	46	432
Unrealized (loss) gain on cash flow hedges	(5)	2	(1)
Other comprehensive (loss) income	(88)	89	650
Comprehensive income	2,240	2,260	2,479
Comprehensive income attributable to noncontrolling interests	—	1	123
Comprehensive income attributable to common shareholders	$ 2,240	$ 2,259	$ 2,356
Average shares of common stock outstanding:			
Basic	996	986	979
Assumed exercise and/or distributions of stock-based awards	1	1	1
Diluted	997	987	980
Earnings per average common share from continuing operations			
Basic	$ 2.34	$ 2.08	$ 1.65
Diluted	$ 2.34	$ 2.08	$ 1.65
Earnings per average common share from discontinued operations			
Basic	$ —	$ 0.12	$ 0.09
Diluted	$ —	$ 0.12	$ 0.09

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, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 2,328	$ 2,171	$ 1,829
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	3,506	3,533	7,573
Asset impairments	—	48	552
Gain on sales of assets and businesses	(10)	(8)	(201)
Deferred income taxes and amortization of investment tax credits	319	255	18
Net fair value changes related to derivatives	22	(53)	(568)
Net realized and unrealized losses (gains) on NDT funds	—	205	(586)
Net unrealized losses on equity investments	—	16	160
Other non-cash operating activities	(335)	370	(200)
Changes in assets and liabilities:			
Accounts receivable	(37)	(1,222)	(703)
Inventories	(45)	(121)	(141)
Accounts payable and accrued expenses	(191)	1,318	440
Option premiums paid, net	—	(39)	(338)
Collateral (paid) received, net	(146)	1,248	(74)
Income taxes	48	(4)	327
Regulatory assets and liabilities, net	(439)	(1,326)	(634)
Pension and non-pension postretirement benefit contributions	(129)	(616)	(665)
Other assets and liabilities	(188)	(905)	(3,777)
Net cash flows provided by operating activities	4,703	4,870	3,012
Cash flows from investing activities			
Capital expenditures	(7,408)	(7,147)	(7,981)
Proceeds from NDT fund sales	—	488	6,532
Investment in NDT funds	—	(516)	(6,673)
Collection of DPP	—	169	3,902
Proceeds from sales of assets and businesses	25	16	877
Other investing activities	8	—	26
Net cash flows used in investing activities	(7,375)	(6,990)	(3,317)
Cash flows from financing activities			
Changes in short-term borrowings	(313)	986	269
Proceeds from short-term borrowings with maturities greater than 90 days	400	1,300	1,380
Repayments on short-term borrowings with maturities greater than 90 days	(150)	(1,500)	(350)
Issuance of long-term debt	5,825	6,309	3,481
Retirement of long-term debt	(1,713)	(2,073)	(1,640)
Issuance of common stock	140	563	—
Dividends paid on common stock	(1,433)	(1,334)	(1,497)
Acquisition of CENG noncontrolling interest	—	—	(885)
Proceeds from employee stock plans	41	36	80
Transfer of cash, restricted cash, and cash equivalents to Constellation	—	(2,594)	—
Other financing activities	(114)	(102)	(80)
Net cash flows provided by financing activities	2,683	1,591	758
Increase (decrease) in cash, restricted cash, and cash equivalents	11	(529)	453
Cash, restricted cash, and cash equivalents at beginning of period	1,090	1,619	1,166
Cash, restricted cash, and cash equivalents at end of period	$ 1,101	$ 1,090	$ 1,619
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (215)	$ 36	$ 16
Increase in DPP	—	348	3,652
(Decrease) increase in PP&E related to ARO update	(13)	332	642

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023		December 31, 2022	
ASSETS				
Current assets				
Cash and cash equivalents		$ 445		$ 407
Restricted cash and cash equivalents		482		566
Accounts receivable				
Customer accounts receivable	2,659		2,544	
Customer allowance for credit losses	(317)		(327)	
Customer accounts receivable, net		2,342		2,217
Other accounts receivable	1,101		1,426	
Other allowance for credit losses	(82)		(82)	
Other accounts receivable, net		1,019		1,344
Inventories, net				
Fossil fuel		94		208
Materials and supplies		707		547
Regulatory assets		2,215		1,641
Other		473		406
Total current assets		7,777		7,336
Property, plant, and equipment (net of accumulated depreciation and amortization of $17,251 and $15,930 as of December 31, 2023 and 2022, respectively)		73,593		69,076
Deferred debits and other assets				
Regulatory assets		8,698		8,037
Goodwill		6,630		6,630
Receivable related to Regulatory Agreement Units		3,232		2,897
Investments		251		232
Other		1,365		1,141
Total deferred debits and other assets		20,176		18,937
Total assets		$ 101,546		$ 95,349

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 2,523	$ 2,586
Long-term debt due within one year	1,403	1,802
Accounts payable	2,846	3,382
Accrued expenses	1,375	1,226
Payables to affiliates	5	5
Regulatory liabilities	389	437
Mark-to-market derivative liabilities	74	8
Unamortized energy contract liabilities	8	10
Other	968	1,155
Total current liabilities	9,591	10,611
Long-term debt	39,692	35,272
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,956	11,250
Regulatory liabilities	9,576	9,112
Pension obligations	1,571	1,109
Non-pension postretirement benefit obligations	527	507
Asset retirement obligations	267	269
Mark-to-market derivative liabilities	106	83
Unamortized energy contract liabilities	27	35
Other	2,088	1,967
Total deferred credits and other liabilities	26,118	24,332
Total liabilities	75,791	70,605
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 999 shares and 994 shares outstanding as of December 31, 2023 and 2022, respectively)	21,114	20,908
Treasury stock, at cost (2 shares as of December 31, 2023 and 2022)	(123)	(123)
Retained earnings	5,490	4,597
Accumulated other comprehensive loss, net	(726)	(638)
Total shareholders' equity	25,755	24,744
Total liabilities and shareholders' equity	$ 101,546	$ 95,349

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	Noncontrolling Interests	Total Equity
Balance at December 31, 2020	977,466	$ 19,373	$ (123)	$ 16,735	$ (3,400)	$ 2,283	$ 34,868
Net income	—	—	—	1,706	—	123	1,829
Long-term incentive plan activity	1,734	69	—	—	—	—	69
Employee stock purchase plan issuances	2,091	90	—	—	—	—	90
Changes in equity of noncontrolling interests	—	—	—	—	—	(37)	(37)
Acquisition of CENG noncontrolling interest	—	1,080	—	—	—	(1,965)	(885)
Deferred tax adjustment related to acquisition of CENG noncontrolling interest	—	(290)	—	—	—	—	(290)
Common stock dividends ($1.53/common share)	—	—	—	(1,499)	—	—	(1,499)
Acquisition of other noncontrolling interest	—	2	—	—	—	(2)	—
Other comprehensive income, net of income taxes	—	—	—	—	650	—	650
Balance at December 31, 2021	981,291	$ 20,324	$ (123)	$ 16,942	$ (2,750)	$ 402	$ 34,795
Net income	—	—	—	2,170	—	1	2,171
Long-term incentive plan activity	561	1	—	—	—	—	1
Employee stock purchase plan issuances	983	41	—	—	—	—	41
Changes in equity of noncontrolling interests	—	—	—	—	—	(7)	(7)
Distribution of Constellation (Note 2)	—	(21)	—	(13,179)	2,023	(396)	(11,573)
Issuance of common stock	12,995	563	—	—	—	—	563
Common stock dividends ($1.35/common share)	—	—	—	(1,336)	—	—	(1,336)
Other comprehensive income, net of income taxes	—	—	—	—	89	—	89
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 issuances	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

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	For the Years Ended December 31, 2023	2022	2021
Operating revenues			
Electric operating revenues	$ 7,272	$ 5,478	$ 6,323
Revenues from alternative revenue programs	556	267	42
Operating revenues from affiliates	16	16	41
Total operating revenues	7,844	5,761	6,406
Operating expenses			
Purchased power	2,816	1,050	1,888
Purchased power from affiliates	—	59	383
Operating and maintenance	1,096	1,094	1,048
Operating and maintenance from affiliates	354	318	307
Depreciation and amortization	1,403	1,323	1,205
Taxes other than income taxes	369	374	320
Total operating expenses	6,038	4,218	5,151
Loss on sale of assets	—	(2)	—
Operating income	1,806	1,541	1,255
Other income and (deductions)			
Interest expense, net	(464)	(401)	(376)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	75	54	48
Total other income and (deductions)	(402)	(360)	(341)
Income before income taxes	1,404	1,181	914
Income taxes	314	264	172
Net income	$ 1,090	$ 917	$ 742
Comprehensive income	$ 1,090	$ 917	$ 742

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, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 1,090	$ 917	$ 742
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	1,403	1,323	1,205
Deferred income taxes and amortization of investment tax credits	196	241	244
Other non-cash operating activities	(536)	(165)	126
Changes in assets and liabilities:			
Accounts receivable	(138)	(163)	(25)
Receivables from and payables to affiliates, net	(2)	(34)	32
Inventories	(82)	(28)	(2)
Accounts payable and accrued expenses	(87)	406	—
Collateral received, net	69	51	—
Income taxes	106	—	—
Regulatory assets and liabilities, net	(60)	(1,033)	(388)
Pension and non-pension postretirement benefit contributions	(41)	(184)	(196)
Other assets and liabilities	(70)	(134)	(143)
Net cash flows provided by operating activities	1,848	1,197	1,595
Cash flows from investing activities			
Capital expenditures	(2,576)	(2,506)	(2,387)
Other investing activities	8	28	26
Net cash flows used in investing activities	(2,568)	(2,478)	(2,361)
Cash flows from financing activities			
Changes in short-term borrowings	(225)	427	(323)
Proceeds from short-term borrowings with maturities greater than 90 days	400	150	—
Repayments on short-term borrowings with maturities greater than 90 days	(150)	—	—
Issuance of long-term debt	975	750	1,150
Retirement of long-term debt	—	—	(350)
Dividends paid on common stock	(746)	(578)	(507)
Contributions from parent	655	670	791
Other financing activities	(14)	(11)	(16)
Net cash flows provided by financing activities	895	1,408	745
Increase (decrease) in cash, restricted cash, and cash equivalents	175	127	(21)
Cash, restricted cash, and cash equivalents at beginning of period	511	384	405
Cash, restricted cash, and cash equivalents at end of period	$ 686	$ 511	$ 384
Supplemental cash flow information			
Decrease in capital expenditures not paid	$ (10)	$ (20)	$ (46)

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)		December 31, 2023		2022
ASSETS				
Current assets				
Cash and cash equivalents		$ 110		$ 67
Restricted cash and cash equivalents		402		327
Accounts receivable				
Customer accounts receivable	860		558	
Customer allowance for credit losses	(69)		(59)	
Customer accounts receivable, net		791		499
Other accounts receivable	242		441	
Other allowance for credit losses	(17)		(17)	
Other accounts receivable, net		225		424
Receivables from affiliates		3		3
Inventories, net		279		196
Regulatory assets		1,335		775
Other		123		92
Total current assets		3,268		2,383
Property, plant, and equipment (net of accumulated depreciation and amortization of $7,222 and $6,673 as of December 31, 2023 and 2022, respectively)		29,088		27,513
Deferred debits and other assets				
Regulatory assets		2,794		2,667
Goodwill		2,625		2,625
Receivable related to Regulatory Agreement Units		2,954		2,660
Investments		6		6
Prepaid pension asset		1,217		1,206
Other		875		601
Total deferred debits and other assets		10,471		9,765
Total assets		$ 42,827		$ 39,661

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 602	$ 577
Long-term debt due within one year	250	—
Accounts payable	867	1,010
Accrued expenses	576	415
Payables to affiliates	72	74
Customer deposits	118	108
Regulatory liabilities	191	226
Mark-to-market derivative liabilities	27	5
Other	219	191
Total current liabilities	2,922	2,606
Long-term debt	11,236	10,518
Long-term debt to financing trusts	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,327	5,021
Regulatory liabilities	7,493	6,913
Asset retirement obligations	149	148
Non-pension postretirement benefit obligations	161	165
Mark-to-market derivative liabilities	106	79
Other	865	642
Total deferred credits and other liabilities	14,101	12,968
Total liabilities	28,464	26,297
Commitments and contingencies		
Shareholders' equity		
Common stock ($12.50 par value, 250 shares authorized, 127 shares outstanding as of December 31, 2023 and 2022)	1,588	1,588
Other paid-in capital	10,401	9,746
Retained earnings	2,374	2,030
Total shareholders' equity	14,363	13,364
Total liabilities and shareholders' equity	$ 42,827	$ 39,661

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, 2020	$ 1,588	$ 8,285	$ 1,456	$ 11,329
Net income	—	—	742	742
Common stock dividends	—	—	(507)	(507)
Contributions from parent	—	791	—	791
Balance at December 31, 2021	$ 1,588	$ 9,076	$ 1,691	$ 12,355
Net income	—	—	917	917
Common stock dividends	—	—	(578)	(578)
Contributions from parent	—	670	—	670
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

See the Combined Notes to Consolidated Financial Statements

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

	For the Years Ended December 31,		
(In millions)	2023	2022	2021
Operating revenues			
Electric operating revenues	$ 3,202	$ 3,156	$ 2,613
Natural gas operating revenues	690	738	538
Revenues from alternative revenue programs	(7)	2	26
Operating revenues from affiliates	9	7	21
Total operating revenues	3,894	3,903	3,198
Operating expenses			
Purchased power	1,270	1,160	699
Purchased fuel	274	342	188
Purchased power from affiliates	—	33	194
Operating and maintenance	786	791	757
Operating and maintenance from affiliates	217	201	177
Depreciation and amortization	397	373	348
Taxes other than income taxes	202	202	184
Total operating expenses	3,146	3,102	2,547
Operating income	748	801	651
Other income and (deductions)			
Interest expense, net	(192)	(165)	(149)
Interest expense to affiliates, net	(9)	(12)	(12)
Other, net	36	31	26
Total other income and (deductions)	(165)	(146)	(135)
Income before income taxes	583	655	516
Income taxes	20	79	12
Net income	$ 563	$ 576	$ 504
Comprehensive income	$ 563	$ 576	$ 504

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, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 563	$ 576	$ 504
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	397	373	348
Deferred income taxes and amortization of investment tax credits	(43)	70	11
Other non-cash operating activities	13	40	—
Changes in assets and liabilities:			
Accounts receivable	67	(205)	(35)
Receivables from and payables to affiliates, net	(1)	(31)	21
Inventories	34	(56)	(26)
Accounts payable and accrued expenses	(78)	152	15
Income taxes	86	(20)	5
Regulatory assets and liabilities, net	(31)	(45)	(21)
Pension and non-pension postretirement benefit contributions	(1)	(18)	(18)
Other assets and liabilities	13	5	(31)
Net cash flows provided by operating activities	1,019	841	773
Cash flows from investing activities			
Capital expenditures	(1,426)	(1,349)	(1,240)
Other investing activities	2	8	9
Net cash flows used in investing activities	(1,424)	(1,341)	(1,231)
Cash flows from financing activities			
Change in short-term borrowings	(74)	239	—
Issuance of long-term debt	575	775	750
Retirement of long-term debt	(50)	(350)	(300)
Changes in Exelon intercompany money pool	—	—	(40)
Dividends paid on common stock	(405)	(399)	(339)
Contributions from parent	348	274	414
Other financing activities	(6)	(15)	(9)
Net cash flows provided by financing activities	388	524	476
(Decrease) increase in cash, restricted cash, and cash equivalents	(17)	24	18
Cash, restricted cash, and cash equivalents at beginning of period	68	44	26
Cash, restricted cash, and cash equivalents at end of period	$ 51	$ 68	$ 44
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (56)	$ 9	$ 26

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023		2022	
ASSETS				
Current assets				
Cash and cash equivalents		$ 42		$ 59
Restricted cash and cash equivalents		9		9
Accounts receivable				
Customer accounts receivable	527		635	
Customer allowance for credit losses	(95)		(105)	
Customer accounts receivable, net		432		530
Other accounts receivable	117		153	
Other allowance for credit losses	(8)		(9)	
Other accounts receivable, net		109		144
Receivables from affiliates		2		4
Inventories, net				
Fossil fuel		50		99
Materials and supplies		67		52
Regulatory assets		127		80
Other		65		38
Total current assets		903		1,015
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,097 and $4,078 as of December 31, 2023 and 2022, respectively)		13,128		12,125
Deferred debits and other assets				
Regulatory assets		793		652
Receivable related to Regulatory Agreement Units		278		237
Investments		35		30
Prepaid pension asset		429		413
Other		29		30
Total deferred debits and other assets		1,564		1,362
Total assets		$ 15,595		$ 14,502

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 165	$ 239
Long-term debt due within one year	—	50
Accounts payable	512	668
Accrued expenses	236	142
Payables to affiliates	39	42
Customer deposits	79	63
Regulatory liabilities	92	75
Other	59	32
Total current liabilities	1,182	1,311
Long-term debt	5,134	4,562
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,321	2,213
Regulatory liabilities	314	270
Asset retirement obligations	26	28
Non-pension postretirement benefit obligations	286	286
Other	79	85
Total deferred credits and other liabilities	3,026	2,882
Total liabilities	9,526	8,939
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 500 shares authorized, 170 shares outstanding as of December 31, 2023 and 2022)	4,050	3,702
Retained earnings	2,019	1,861
Total shareholder's equity	6,069	5,563
Total liabilities and shareholder's equity	$ 15,595	$ 14,502

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, 2020	$ 3,014	$ 1,519	$ 4,533
Net income	—	504	504
Common stock dividends	—	(339)	(339)
Contributions from parent	414	—	414
Balance at December 31, 2021	$ 3,428	$ 1,684	$ 5,112
Net income	—	576	576
Common stock dividends	—	(399)	(399)
Contributions from parent	274	—	274
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

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2023	2022	2021
Operating revenues			
Electric operating revenues	$ 3,065	$ 2,890	$ 2,497
Natural gas operating revenues	869	1,037	801
Revenues from alternative revenue programs	84	(47)	12
Operating revenues from affiliates	9	15	31
Total operating revenues	4,027	3,895	3,341
Operating expenses			
Purchased power	1,311	1,186	699
Purchased fuel	220	363	243
Purchased power and fuel from affiliates	—	18	233
Operating and maintenance	520	670	618
Operating and maintenance from affiliates	221	207	193
Depreciation and amortization	654	630	591
Taxes other than income taxes	319	302	283
Total operating expenses	3,245	3,376	2,860
Operating income	782	519	481
Other income and (deductions)			
Interest expense, net	(182)	(152)	(138)
Other, net	18	21	30
Total other income and (deductions)	(164)	(131)	(108)
Income before income taxes	618	388	373
Income taxes	133	8	(35)
Net income	$ 485	$ 380	$ 408
Comprehensive income	$ 485	$ 380	$ 408

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, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 485	$ 380	$ 408
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	654	630	591
Asset impairments	—	48	—
Deferred income taxes and amortization of investment tax credits	66	9	(17)
Other non-cash operating activities	(1)	135	75
Changes in assets and liabilities:			
Accounts receivable	89	(197)	30
Receivables from and payables to affiliates, net	(5)	(2)	(13)
Inventories	47	(61)	(29)
Accounts payable and accrued expenses	(75)	77	14
Collateral (paid) received, net	(22)	19	3
Income taxes	37	(17)	20
Regulatory assets and liabilities, net	(292)	(160)	(152)
Pension and non-pension postretirement benefit contributions	(19)	(68)	(81)
Other assets and liabilities	(13)	(33)	(120)
Net cash flows provided by operating activities	951	760	729
Cash flows from investing activities			
Capital expenditures	(1,367)	(1,262)	(1,226)
Other investing activities	7	11	18
Net cash flows used in investing activities	(1,360)	(1,251)	(1,208)
Cash flows from financing activities			
Changes in short-term borrowings	(72)	278	130
Issuance of long-term debt	700	500	600
Retirement of long-term debt	(300)	(250)	(300)
Dividends paid on common stock	(316)	(300)	(292)
Contributions from parent	385	286	257
Other financing activities	(7)	(11)	(6)
Net cash flows provided by financing activities	390	503	389
(Decrease) increase in cash, restricted cash, and cash equivalents	(19)	12	(90)
Cash, restricted cash, and cash equivalents at beginning of period	67	55	145
Cash, restricted cash, and cash equivalents at end of period	$ 48	$ 67	$ 55
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (44)	$ 35	$ (59)

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2023		December 31, 2022	
ASSETS				
Current assets				
Cash and cash equivalents	$	47	$	43
Restricted cash and cash equivalents		1		24
Accounts receivable				
Customer accounts receivable	527		617	
Customer allowance for credit losses	(46)		(54)	
Customer accounts receivable, net		481		563
Other accounts receivable	106		132	
Other allowance for credit losses	(7)		(10)	
Other accounts receivable, net		99		122
Inventories, net				
Fossil fuel		35		91
Materials and supplies		74		65
Prepaid utility taxes		56		52
Regulatory assets		229		177
Other		25		13
Total current assets		1,047		1,150
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,744 and $4,583 as of December 31, 2023 and 2022, respectively)		12,102		11,338
Deferred debits and other assets				
Regulatory assets		727		527
Investments		9		7
Prepaid pension asset		248		291
Other		51		37
Total deferred debits and other assets		1,035		862
Total assets	$	14,184	$	13,350

See the Combined Notes to Consolidated Financial Statements

Baltimore Gas and Electric Company
Balance Sheets

(In millions)	December 31, 2023	2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 336	$ 408
Long-term debt due within one year	—	300
Accounts payable	344	462
Accrued expenses	203	159
Payables to affiliates	35	39
Customer deposits	114	105
Regulatory liabilities	27	47
Other	34	55
Total current liabilities	1,093	1,575
Long-term debt	4,602	3,907
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,945	1,832
Regulatory liabilities	773	816
Asset retirement obligations	32	30
Non-pension postretirement benefit obligations	158	166
Other	91	88
Total deferred credits and other liabilities	2,999	2,932
Total liabilities	8,694	8,414
Commitments and contingencies		
Shareholder's equity		
Common stock (No par value, 0 shares[a] authorized, 0 shares[a] outstanding as of December 31, 2023 and 2022)	3,246	2,861
Retained earnings	2,244	2,075
Total shareholder's equity	5,490	4,936
Total liabilities and shareholder's equity	$ 14,184	$ 13,350

(a) In millions, shares round to zero. Number of shares is 1,500 authorized and 1,000 outstanding as of December 31, 2023 and 2022.

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, 2020	$ 2,318	$ 1,879	$ 4,197
Net income	—	408	408
Common stock dividends	—	(292)	(292)
Contributions from parent	257	—	257
Balance at December 31, 2021	$ 2,575	$ 1,995	$ 4,570
Net income	—	380	380
Common stock dividends	—	(300)	(300)
Contributions from parent	286	—	286
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

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	For the Years Ended December 31, 2023	2022	2021
Operating revenues			
Electric operating revenues	$ 5,748	$ 5,376	$ 4,769
Natural gas operating revenues	205	238	168
Revenues from alternative revenue programs	64	(59)	91
Operating revenues from affiliates	9	10	13
Total operating revenues	6,026	5,565	5,041
Operating expenses			
Purchased power	2,250	1,984	1,417
Purchased fuel	98	129	73
Purchased power from affiliates	—	51	367
Operating and maintenance	1,110	966	925
Operating and maintenance from affiliates	179	191	179
Depreciation and amortization	990	938	821
Taxes other than income taxes	487	475	458
Total operating expenses	5,114	4,734	4,240
Gain on sales of assets	9	—	—
Operating income	921	831	801
Other income and (deductions)			
Interest expense, net	(323)	(292)	(267)
Other, net	108	78	69
Total other income and (deductions)	(215)	(214)	(198)
Income before income taxes	706	617	603
Income taxes	116	9	42
Net income	$ 590	$ 608	$ 561
Comprehensive income	$ 590	$ 608	$ 561

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, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 590	$ 608	$ 561
Adjustments to reconcile net income to net cash flows used in operating activities:			
Depreciation and amortization	990	938	821
Gain on sales of assets	(9)	—	—
Deferred income taxes and amortization of investment tax credits	29	(9)	24
Other non-cash operating activities	110	163	(12)
Changes in assets and liabilities:			
Accounts receivable	(79)	(184)	(48)
Receivables from and payables to affiliates, net	(8)	(46)	6
Inventories	(42)	(34)	(16)
Accounts payable and accrued expenses	40	30	34
Collateral (paid) received, net	(196)	148	49
Income taxes	65	(1)	17
Regulatory assets and liabilities, net	(61)	(136)	(99)
Pension and non-pension postretirement benefit contributions	(24)	(78)	(48)
Other assets and liabilities	(101)	(149)	(132)
Net cash flows provided by operating activities	1,304	1,250	1,157
Cash flows from investing activities			
Capital expenditures	(1,988)	(1,709)	(1,720)
Proceeds from sales of long-lived assets	10	—	—
Other investing activities	8	6	2
Net cash flows used in investing activities	(1,970)	(1,703)	(1,718)
Cash flows from financing activities			
Changes in short-term borrowings	(20)	(54)	100
Issuance of long-term debt	1,075	925	825
Retirement of long-term debt	(500)	(310)	(260)
Change in Exelon intercompany money pool	21	37	(14)
Distributions to member	(513)	(750)	(703)
Contributions from member	475	787	683
Other financing activities	(41)	(22)	(17)
Net cash flows provided by financing activities	497	613	614
(Decrease) increase in cash, restricted cash, and cash equivalents	(169)	160	53
Cash, restricted cash, and cash equivalents at beginning of period	373	213	160
Cash, restricted cash, and cash equivalents at end of period	$ 204	$ 373	$ 213
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (109)	$ 136	$ (6)

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023		December 31, 2022	
ASSETS				
Current assets				
Cash and cash equivalents		$ 180		$ 198
Restricted cash and cash equivalents		24		175
Accounts receivable				
Customer accounts receivable	745		734	
Customer allowance for credit losses	(107)		(109)	
Customer accounts receivable, net		638		625
Other accounts receivable	310		300	
Other allowance for credit losses	(50)		(46)	
Other accounts receivable, net		260		254
Receivable from affiliates		3		2
Inventories, net				
Fossil fuel		9		18
Materials and supplies		287		236
Regulatory assets		337		455
Other		100		96
Total current assets		1,838		2,059
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,175 and $2,618 as of December 31, 2023 and 2022, respectively)		18,851		17,686
Deferred debits and other assets				
Regulatory assets		1,587		1,610
Goodwill		4,005		4,005
Investments		143		138
Prepaid pension asset		268		353
Other		211		231
Total deferred debits and other assets		6,214		6,337
Total assets		$ 26,903		$ 26,082

See the Combined Notes to Consolidated Financial Statements

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2023	December 31, 2022
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 394	$ 414
Long-term debt due within one year	644	591
Accounts payable	683	771
Accrued expenses	338	260
Payables to affiliates	59	66
Borrowings from Exelon intercompany money pool	65	44
Customer deposits	100	88
Regulatory liabilities	71	76
Unamortized energy contract liabilities	8	10
PPA Termination Obligation	49	87
Other	138	330
Total current liabilities	2,549	2,737
Long-term debt	8,004	7,529
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,031	2,895
Regulatory liabilities	904	1,011
Asset retirement obligations	55	59
Non-pension postretirement benefit obligations	40	50
Unamortized energy contract liabilities	27	35
Other	511	536
Total deferred credits and other liabilities	4,568	4,586
Total liabilities	15,121	14,852
Commitments and contingencies		
Member's equity		
Membership interest	12,057	11,582
Undistributed losses	(275)	(352)
Total member's equity	11,782	11,230
Total liabilities and member's equity	$ 26,903	$ 26,082

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Membership Interest	Undistributed (Losses)/Gains	Total Member's Equity
Balance at December 31, 2020	$ 10,112	$ (68)	$ 10,044
Net income	—	561	561
Distribution to member	—	(703)	(703)
Contributions from member	683	—	683
Balance at December 31, 2021	$ 10,795	$ (210)	$ 10,585
Net Income	—	608	608
Distribution to member	—	(750)	(750)
Contributions from member	787	—	787
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

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2023	2022	2021
Operating revenues			
Electric operating revenues	$ 2,793	$ 2,557	$ 2,216
Revenues from alternative revenue programs	22	(31)	53
Operating revenues from affiliates	9	5	5
Total operating revenues	2,824	2,531	2,274
Operating expenses			
Purchased power	974	795	353
Purchased power from affiliate	—	39	271
Operating and maintenance	336	284	258
Operating and maintenance from affiliates	236	223	213
Depreciation and amortization	441	417	403
Taxes other than income taxes	390	382	373
Total operating expenses	2,377	2,140	1,871
Gain on sales of assets	9	—	—
Operating income	456	391	403
Other income and (deductions)			
Interest expense, net	(165)	(150)	(140)
Other, net	66	55	48
Total other income and (deductions)	(99)	(95)	(92)
Income before income taxes	357	296	311
Income taxes	51	(9)	15
Net income	$ 306	$ 305	$ 296
Comprehensive income	$ 306	$ 305	$ 296

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 306	$ 305	$ 296
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	441	417	403
Gain on sales of assets	(9)	—	—
Deferred income taxes and amortization of investment tax credits	(15)	(17)	(8)
Other non-cash operating activities	53	36	(52)
Changes in assets and liabilities:			
Accounts receivable	(29)	(104)	(28)
Receivables from and payables to affiliates, net	(3)	(33)	6
Inventories	(24)	(16)	(8)
Accounts payable and accrued expenses	6	24	16
Collateral (paid) received, net	(25)	24	2
Income taxes	60	(19)	11
Regulatory assets and liabilities, net	(45)	(69)	(81)
Pension and non-pension postretirement benefit contributions	(12)	(11)	(11)
Other assets and liabilities	(5)	(66)	(84)
Net cash flows provided by operating activities	699	471	462
Cash flows from investing activities			
Capital expenditures	(957)	(874)	(843)
Proceeds from sale of long-lived assets	10	—	—
Other investing activities	8	3	(1)
Net cash flows used in investing activities	(939)	(871)	(844)
Cash flows from financing activities			
Changes in short-term borrowings	(167)	124	140
Issuance of long-term debt	350	625	275
Retirement of long-term debt	—	(310)	—
Dividends paid on common stock	(252)	(463)	(268)
Contributions from parent	308	465	244
Other financing activities	(26)	(10)	(6)
Net cash flows provided by financing activities	213	431	385
(Decrease) increase in cash, restricted cash, and cash equivalents	(27)	31	3
Cash, restricted cash, and cash equivalents at beginning of period	99	68	65
Cash, restricted cash, and cash equivalents at end of period	$ 72	$ 99	$ 68
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (55)	$ 65	$ 30

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2023		2022	
ASSETS				
Current assets				
Cash and cash equivalents	$	48	$	45
Restricted cash and cash equivalents		24		54
Accounts receivable				
Customer accounts receivable	369		351	
Customer allowance for credit losses	(52)		(47)	
Customer accounts receivable, net		317		304
Other accounts receivable	166		180	
Other allowance for credit losses	(28)		(25)	
Other accounts receivable, net		138		155
Receivables from affiliates		2		—
Inventories, net		159		135
Regulatory assets		150		235
Other		51		53
Total current assets		889		981
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,284 and $4,067 as of December 31, 2023 and 2022, respectively)		9,430		8,794
Deferred debits and other assets				
Regulatory assets		450		437
Investments		124		119
Prepaid pension asset		246		273
Other		55		53
Total deferred debits and other assets		875		882
Total assets	$	11,194	$	10,657

See the Combined Notes to Consolidated Financial Statements

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2023	2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 132	$ 299
Long-term debt due within one year	405	4
Accounts payable	321	382
Accrued expenses	191	125
Payables to affiliates	32	34
Customer deposits	47	39
Regulatory liabilities	15	6
Merger related obligation	25	26
Other	61	93
Total current liabilities	1,229	1,008
Long-term debt	3,691	3,747
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,431	1,382
Regulatory liabilities	382	455
Asset retirement obligations	37	39
Other	280	244
Total deferred credits and other liabilities	2,130	2,120
Total liabilities	7,050	6,875
Commitments and contingencies		
Shareholder's equity		
Common stock ($0.01 par value, 200 shares authorized, 0 shares[(a)] outstanding as of December 31, 2023 and 2022)	3,075	2,767
Retained earnings	1,069	1,015
Total shareholder's equity	4,144	3,782
Total liabilities and shareholder's equity	$ 11,194	$ 10,657

(a) In millions, shares round to zero. Number of shares is 100 outstanding as of December 31, 2023 and 2022.

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, 2020	$ 2,058	$ 1,145	$ 3,203
Net income	—	296	296
Common stock dividends	—	(268)	(268)
Contributions from parent	244	—	244
Balance at December 31, 2021	$ 2,302	$ 1,173	$ 3,475
Net income	—	305	305
Common stock dividends	—	(463)	(463)
Contributions from parent	465	—	465
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

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, 2023	2022	2021
Operating revenues			
Electric operating revenues	$ 1,460	$ 1,360	$ 1,191
Natural gas operating revenues	205	238	168
Revenues from alternative revenue programs	15	(9)	14
Operating revenues from affiliates	8	6	7
Total operating revenues	1,688	1,595	1,380
Operating expenses			
Purchased power	639	567	387
Purchased fuel	98	129	73
Purchased power from affiliates	—	10	79
Operating and maintenance	193	183	183
Operating and maintenance from affiliates	171	166	162
Depreciation and amortization	244	232	210
Taxes other than income taxes	75	72	67
Total operating expenses	1,420	1,359	1,161
Operating income	268	236	219
Other income and (deductions)			
Interest expense, net	(74)	(66)	(61)
Other, net	18	13	12
Total other income and (deductions)	(56)	(53)	(49)
Income before income taxes	212	183	170
Income taxes	35	14	42
Net income	$ 177	$ 169	$ 128
Comprehensive income	$ 177	$ 169	$ 128

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 177	$ 169	$ 128
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	244	232	210
Deferred income taxes and amortization of investment tax credits	4	16	39
Other non-cash operating activities	13	29	3
Changes in assets and liabilities:			
Accounts receivable	6	(59)	15
Receivables from and payables to affiliates, net	2	(10)	(3)
Inventories	(5)	(11)	(8)
Accounts payable and accrued expenses	(7)	19	16
Collateral (paid) received, net	(121)	78	43
Income taxes	26	—	13
Regulatory assets and liabilities, net	25	(34)	(43)
Pension and non-pension postretirement benefit contributions	(4)	(1)	(1)
Other assets and liabilities	13	(10)	(27)
Net cash flows provided by operating activities	373	418	385
Cash flows from investing activities			
Capital expenditures	(562)	(430)	(429)
Other investing activities	—	3	4
Net cash flows used in investing activities	(562)	(427)	(425)
Cash flows from financing activities			
Changes in short-term borrowings	(52)	(34)	3
Issuance of long-term debt	650	125	125
Retirement of long-term debt	(500)	—	—
Dividends paid on common stock	(133)	(143)	(147)
Contributions from parent	99	147	120
Other financing activities	(11)	(5)	(5)
Net cash flows provided by financing activities	53	90	96
(Decrease) increase in cash, restricted cash, and cash equivalents	(136)	81	56
Cash, restricted cash, and cash equivalents at beginning of period	152	71	15
Cash, restricted cash, and cash equivalents at end of period	$ 16	$ 152	$ 71
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (6)	$ 23	$ (18)

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2023	2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 16	$ 31
Restricted cash and cash equivalents	—	121
Accounts receivable		
Customer accounts receivable	183	204
Customer allowance for credit losses	(19)	(21)
Customer accounts receivable, net	164	183
Other accounts receivable	52	52
Other allowance for credit losses	(8)	(7)
Other accounts receivable, net	44	45
Receivables from affiliates	1	—
Inventories, net		
Fossil fuel	9	18
Materials and supplies	72	58
Prepaid utility taxes	24	23
Regulatory assets	54	80
Other	14	14
Total current assets	398	573
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,925 and $1,772 as of December 31, 2023 and 2022, respectively)	5,165	4,820
Deferred debits and other assets		
Regulatory assets	218	202
Prepaid pension asset	135	153
Other	50	54
Total deferred debits and other assets	403	409
Total assets	$ 5,966	$ 5,802

See the Combined Notes to Consolidated Financial Statements

Delmarva Power & Light Company
Balance Sheets

(In millions)	December 31, 2023	December 31, 2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 63	$ 115
Long-term debt due within one year	84	584
Accounts payable	159	172
Accrued expenses	64	41
Payables to affiliates	25	22
Customer deposits	31	29
Regulatory liabilities	50	44
Other	21	136
Total current liabilities	497	1,143
Long-term debt	1,996	1,354
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	904	869
Regulatory liabilities	365	380
Asset retirement obligations	12	13
Non-pension postretirement benefit obligations	6	9
Other	93	84
Total deferred credits and other liabilities	1,380	1,355
Total liabilities	3,873	3,852
Commitments and contingencies		
Shareholder's equity		
Common stock ($2.25 par value, 0 shares[(a)] authorized, 0 shares[(a)] outstanding as of December 31, 2023 and 2022, respectively)	1,455	1,356
Retained earnings	638	594
Total shareholder's equity	2,093	1,950
Total liabilities and shareholder's equity	$ 5,966	$ 5,802

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(a) In millions, shares round to zero. Number of shares is 1,000 authorized and outstanding as of December 31, 2023 and 2022.

See the Combined Notes to Consolidated Financial Statements

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, 2020	$ 1,089	$ 587	$ 1,676
Net income	—	128	128
Common stock dividends	—	(147)	(147)
Contributions from parent	120	—	120
Balance at December 31, 2021	$ 1,209	$ 568	$ 1,777
Net income	—	169	169
Common stock dividends	—	(143)	(143)
Contributions from parent	147	—	147
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

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, 2023	2022	2021
Operating revenues			
Electric operating revenues	$ 1,493	$ 1,448	$ 1,362
Revenues from alternative revenue programs	27	(19)	24
Operating revenues from affiliates	2	2	2
Total operating revenues	1,522	1,431	1,388
Operating expenses			
Purchased power	637	622	677
Purchased power from affiliate	—	2	17
Operating and maintenance	233	189	179
Operating and maintenance from affiliates	153	142	141
Depreciation and amortization	283	261	179
Taxes other than income taxes	8	9	8
Total operating expenses	1,314	1,225	1,201
Operating income	208	206	187
Other income and (deductions)			
Interest expense, net	(72)	(66)	(58)
Other, net	20	11	4
Total other income and (deductions)	(52)	(55)	(54)
Income before income taxes	156	151	133
Income taxes	36	3	(13)
Net income	$ 120	$ 148	$ 146
Comprehensive income	$ 120	$ 148	$ 146

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	For the Years Ended December 31, 2023	2022	2021
Cash flows from operating activities			
Net income	$ 120	$ 148	$ 146
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	283	261	179
Deferred income taxes and amortization of investment tax credits	27	(2)	(15)
Other non-cash operating activities	—	46	—
Changes in assets and liabilities:			
Accounts receivable	(57)	(19)	(37)
Receivables from and payables to affiliates, net	(4)	(4)	4
Inventories	(12)	(7)	1
Accounts payable and accrued expenses	27	(9)	3
Collateral (paid) received, net	(50)	46	4
Income taxes	—	11	—
Regulatory assets and liabilities, net	(47)	(19)	24
Pension and non-pension postretirement benefit contributions	(3)	(7)	(3)
Other assets and liabilities	(83)	(61)	(11)
Net cash flows provided by operating activities	201	384	295
Cash flows from investing activities			
Capital expenditures	(460)	(398)	(445)
Other investing activities	—	1	1
Net cash flows used in investing activities	(460)	(397)	(444)
Cash flows from financing activities			
Changes in short-term borrowings	199	(144)	(43)
Issuance of long-term debt	75	175	425
Retirement of long-term debt	—	—	(260)
Dividends paid on common stock	(126)	(145)	(288)
Contributions from parent	65	175	319
Other financing activities	(5)	(5)	(5)
Net cash flows provided by financing activities	208	56	148
(Decrease) increase in cash, restricted cash, and cash equivalents	(51)	43	(1)
Cash, restricted cash, and cash equivalents at beginning of period	72	29	30
Cash, restricted cash, and cash equivalents at end of period	$ 21	$ 72	$ 29
Supplemental cash flow information			
(Decrease) increase in capital expenditures not paid	$ (47)	$ 48	$ (18)

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2023		December 31, 2022	
ASSETS				
Current assets				
Cash and cash equivalents	$	21	$	72
Accounts receivable				
Customer accounts receivable	194		179	
Customer allowance for credit losses	(36)		(41)	
Customer accounts receivable, net		158		138
Other accounts receivable	92		70	
Other allowance for credit losses	(14)		(14)	
Other accounts receivable, net		78		56
Receivables from affiliates		3		1
Inventories, net		55		43
Regulatory assets		125		130
Other		5		3
Total current assets		445		443
Property, plant, and equipment, (net of accumulated depreciation and amortization of $1,684 and $1,551 as of December 31, 2023 and 2022, respectively)		4,192		3,990
Deferred debits and other assets				
Regulatory assets		483		494
Prepaid pension asset		3		18
Other		34		34
Total deferred debits and other assets		520		546
Total assets	$	5,157	$	4,979

See the Combined Notes to Consolidated Financial Statements

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2023	2022
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 199	$ —
Long-term debt due within one year	154	3
Accounts payable	192	206
Accrued expenses	42	47
Payables to affiliates	25	26
Customer deposits	23	21
Regulatory liabilities	6	26
PPA termination obligation	49	87
Other	12	58
Total current liabilities	702	474
Long-term debt	1,679	1,754
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	771	734
Regulatory liabilities	140	156
Non-pension postretirement benefit obligations	4	8
Other	49	100
Total deferred credits and other liabilities	964	998
Total liabilities	3,345	3,226
Commitments and contingencies		
Shareholder's equity		
Common stock ($3.00 par value, 25 shares authorized, 9 shares outstanding as of December 31, 2023 and 2022)	1,830	1,765
Retained deficit	(18)	(12)
Total shareholder's equity	1,812	1,753
Total liabilities and shareholder's equity	$ 5,157	$ 4,979

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, 2020	$ 1,271	$ 127	$ 1,398
Net income	—	146	146
Common stock dividends	—	(288)	(288)
Contributions from parent	319	—	319
Balance at December 31, 2021	$ 1,590	$ (15)	$ 1,575
Net income	—	148	148
Common stock dividends	—	(145)	(145)
Contributions from parent	175	—	175
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

See the Combined Notes to Consolidated Financial Statements

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

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.

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation. The separation was completed on February 1, 2022, creating two publicly traded companies, Exelon and Constellation. See Note 2 — Discontinued Operations for additional information.

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 Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated, except for the historical transactions between the Utility Registrants and Generation for the purposes of presenting discontinued operations in all periods presented in the Consolidated Statements of Operations and Comprehensive Income.

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, 2023 and 2022, Exelon owned 100% of PECO, BGE, and PHI and more than 99% of ComEd. PHI owns 100% of Pepco, DPL, and ACE. As of December 31, 2021, Exelon owned 100% of Generation. As of February 1, 2022, as a result of the completion of the separation, Exelon no longer owns any interest in Generation. The separation of Constellation, including Generation and its subsidiaries, meets the criteria for discontinued operations and as such, its results of operations are presented as discontinued operations and have been excluded from continuing operations for all periods presented. Accounting rules require that certain BSC costs previously allocated to Generation be presented as part of Exelon's continuing operations as these costs do not qualify as expenses of the discontinued operations. Comprehensive income, shareholders' equity, and cash flows related to Generation have not been segregated and are included in the Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Changes in Shareholders' Equity, and Consolidated Statements of Cash Flows, respectively, for the periods ended December 31, 2022 and December 31, 2021. See Note 2 — Discontinued Operations for additional information.

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.

COVID-19 (All Registrants)

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

Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and accompanying notes, and the amounts of revenues and expenses reported during the periods covered by those financial statements and accompanying notes. As of December 31, 2023 and 2022, and through the date of this report, management assessed certain accounting matters that require consideration of forecasted financial information, including, but not limited to, allowance for credit losses and the carrying value of goodwill and other long-lived assets, in context with the information reasonably available and the unknown future impacts of COVID-19. The Registrants' future assessment of the magnitude and duration of COVID-19, as well as other factors, could result in material impacts to their consolidated financial statements in future reporting periods.

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, environmental costs and other loss contingencies, AROs, and 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 3 — 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 ARP. 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, 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 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 3 — 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 22 — 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 with a term of greater than one year. Operating lease ROU assets are included in Other deferred debits and other assets and operating lease liabilities are included in Other current liabilities and Other deferred credits and other liabilities on the Consolidated Balance Sheets. Finance lease ROU assets are included in Plant, property, 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 10 — 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, 2023 and 2022, the Registrants' restricted cash and cash equivalents primarily represented the following items:

Registrant[(a)]	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, and costs for the remediation of an MGP site.
PECO	Proceeds from the sales of assets that were subject to PECO's mortgage indenture.
BGE	Proceeds from the loan program for the completion of certain energy efficiency measures and collateral held from energy suppliers.
PHI[(a)]	Payment of merger commitments and collateral held from its energy suppliers associated with procurement contracts.
Pepco	Payment of merger commitments and collateral held from energy suppliers.
DPL	Collateral held from energy suppliers.

(a) As of December 31, 2023 and 2022, ACE had no restricted cash and cash equivalents.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2023 and 2022, the Registrants' noncurrent restricted cash and cash equivalents primarily represented ComEd's over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA and costs for the remediation of an MGP site.

See Note 16 — Debt and Credit Agreements and Note 22 — Supplemental Financial Information for additional information.

Allowance for Credit Losses on Accounts 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 developed by applying loss rates for each Utility Registrant, based on historical loss experience, current conditions, and forward-looking risk factors, to the outstanding receivable balance by customer risk segment. 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 3 - 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 6 — 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 7 — Property, Plant, and Equipment, Note 8 — Jointly Owned Electric Utility Plant and Note 22 — 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 7 — 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 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 3 — Regulatory Matters and Note 22 — 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 9 — 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 by issuing the guarantee. 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 18 — 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 12 — 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 each period. 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 3 — Regulatory Matters and Note 15 — 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 experience different from that assumed on pension and OPEB obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses 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 14 — Retirement Benefits for additional information.

New Accounting Standards (All Registrants)

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2023: 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, 2023. 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.

Segment Reporting (Issued November 2023). Improves reportable segment disclosure requirements, primarily through enhanced disclosures about significant segment expenses. The objective of the revised guidance is to introduce a new requirement to disclose significant segment expenses regularly provided to the CODM, extend certain annual disclosures to interim periods, clarify single reportable segment entities must apply ASC 280 in its entirety, permit more than one measure of segment profit or loss to be reported under certain conditions, and require disclosure of the title and position of the CODM. The standard is effective for annual periods beginning January 1, 2024 and interim periods beginning January 1, 2025, with early adoption permitted. The standard will be applied retrospectively.

Improvement 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 January 1, 2025, with early adoption permitted.

2. Discontinued Operations (Exelon)

On February 21, 2021, Exelon's Board of Directors approved a plan to separate the Utility Registrants and Generation, creating two publicly traded companies ("the separation"). Exelon completed the separation on February 1, 2022, through the distribution of 326,663,937 common stock shares of Constellation, the new publicly traded company, to Exelon shareholders. Under the separation plan, Exelon shareholders retained their current shares of Exelon stock and received one share of Constellation common stock for every three shares of Exelon common stock held on January 20, 2022, the record date for the distribution, in a transaction that was tax-free to Exelon and its shareholders for U.S. federal income tax purposes.

Constellation was newly formed and incorporated in Pennsylvania on June 15, 2021 for the purposes of separation and holds Generation (including Generation's subsidiaries).

Pursuant to the separation:

- Exelon entered into four term loans consisting of a 364-day term loan for $1.15 billion and three 18-month term loans for $300 million, $300 million, and $250 million, respectively. Exelon issued these term loans primarily to fund the cash payment to Constellation and for general corporate purposes. See Note 16 — Debt and Credit Agreements for additional information.
- Exelon made a cash payment of $1.75 billion to Constellation on January 31, 2022.
- Exelon contributed its equity ownership interest in Generation to Constellation. Exelon no longer retains any equity ownership interest in Generation or Constellation.
- Exelon transferred certain corporate assets and employee-related obligations to Constellation.
- Exelon received cash from Generation of $258 million to settle the intercompany loan on January 31, 2022. See Note 16 — Debt and Credit Agreements for additional information.

Continuing Involvement

In order to govern the ongoing relationships between Exelon and Constellation after the separation, and to facilitate an orderly transition, Exelon and Constellation have entered into several agreements, including the following:

- Separation Agreement – governs the rights and obligations between Exelon and Constellation regarding certain actions to be taken in connection with the separation, among others, including the allocation of assets and liabilities between Exelon and Constellation.
- Transition Services Agreement (TSA) – governs the terms and conditions of the services that Exelon provides to Constellation and Constellation provides to Exelon for an expected period of two years, provided that certain services may be longer than the term and services may be extended with approval from both parties. The services include specified accounting, finance, information technology, human resources, employee benefits, and other services that have historically been provided on a centralized basis by BSC. For the year ended December 31, 2023, the amounts Exelon billed Constellation and Constellation billed Exelon for these services were $151 million recorded in Other income, net and $14 million recorded in Operating and maintenance expense, respectively. For the period from February 1, 2022 to December 31, 2022, the amounts Exelon billed Constellation and Constellation billed Exelon for these services were $266 million recorded in Other income, net and $43 million recorded in Operating and maintenance expense, respectively.
- Tax Matters Agreement (TMA) – governs the respective rights, responsibilities and obligations of Exelon and Constellation with respect to all tax matters, including tax liabilities and benefits, tax attributes, tax returns, tax contests and other tax sharing regarding U.S. federal, state, local and foreign income taxes, other tax matters and related tax returns. See Note 13 — Income Taxes for additional information.

In addition, the Utility Registrants will continue to incur expenses from transactions with Constellation after the separation. Prior to the separation, such expenses were primarily recorded as Purchased power from affiliates and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants. After the separation, such expenses are primarily recorded as Purchased power and an immaterial amount recorded as Operating and maintenance expense at the Utility Registrants.

- ComEd had an ICC-approved RFP contract with Constellation to provide a portion of ComEd’s electric supply requirements. ComEd also purchased RECs and ZECs from Constellation.
- PECO received electric supply from Constellation under contracts executed through PECO’s competitive procurement process. In addition, PECO had a ten-year agreement with Constellation to sell solar AECs.
- BGE received a portion of its energy requirements from Constellation under its MDPSC-approved market-based SOS and gas commodity programs.
- Pepco received electric supply from Constellation under contracts executed through Pepco’s competitive procurement process approved by the MDPSC and DCPSC.
- DPL received a portion of its energy requirements from Constellation under its MDPSC and DEPSC approved market-based SOS commodity programs.
- ACE received electric supply from Constellation under contracts executed through ACE’s competitive procurement process approved by the NJBPU.

ComEd and PECO also have receivables with Constellation for estimated excess funds at the end of decommissioning the Regulatory Agreement Units, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 3 — Regulatory Matters and Note 23 — Related Party Transactions for additional information.

Discontinued Operations

The separation represented a strategic shift that had a major effect on Exelon’s operations and financial results. Accordingly, the separation met the criteria for discontinued operations.

There were no results from discontinued operations for the year ended December 31, 2023. The following table presents the results of Constellation that have been reclassified from continuing operations and included in discontinued operations within Exelon’s Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2022 and 2021.

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

These results are primarily Generation, which is comprised of Exelon's Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions reportable segments, and include the impact of transaction costs, certain BSC costs, including any transition costs, that were historically allocated and directly attributable to Generation, transactions between Generation and the Utility Registrants, and tax-related adjustments. Transaction costs include costs for external bankers, accountants, appraisers, lawyers, external counsels and other advisors, among others, who are involved in the negotiation, appraisal, due diligence and regulatory approval of the separation. Transition costs are primarily employee-related costs such as recruitment expenses, costs to establish certain stand-alone functions and information technology systems, professional services fees, and other separation-related costs during the transition to separate Generation. For the purposes of reporting discontinued operations, these results also include transactions between Generation and the Utility Registrants that were historically eliminated within Exelon's Consolidated Statements of Operations, as these transactions will be ongoing after the separation. Certain BSC costs that were historically allocated to Generation are presented as part of continuing operations in Exelon's Consolidated Statements of Operations as these costs do not qualify as expenses of the discontinued operations per the accounting rules.

	For the Years Ended December 31,	
	2022	2021
Operating revenues		
Competitive business revenues	$ 1,855	$ 18,466
Competitive business revenues from affiliates	161	1,189
Total operating revenues	2,016	19,655
Operating expenses		
Competitive businesses purchased power and fuel	1,138	12,163
Operating and maintenance[(a)]	371	4,174
Depreciation and amortization	94	3,003
Taxes other than income taxes	44	475
Total operating expenses	1,647	19,815
Gain on sales of assets and businesses	10	201
Operating income	379	41
Other income and (deductions)		
Interest expense, net	(20)	(282)
Other, net	(281)	795
Total other income and (deductions)	(301)	513
Income before income taxes	78	554
Income taxes	(40)	332
Equity in losses of unconsolidated affiliates	(1)	(9)
Net income	117	213
Net income attributable to noncontrolling interests	1	123
Net income from discontinued operations	$ 116	$ 90

(a) Includes transaction and transition costs related to the separation of $52 million and $43 million for the years ended December 31, 2022 and 2021, respectively.

There were no assets or liabilities of discontinued operations included in Exelon's Consolidated Balance Sheet as of December 31, 2023 and 2022. Constellation had net assets of $11,573 million that separated on February 1, 2022 that resulted in a reduction to Exelon's equity during the year ended December 31, 2022. Refer to the Distribution of Constellation line in Exelon's Consolidated Statement of Changes in Shareholders' Equity for further information.

There were no discontinued operations included within Exelon's Consolidated Statements of Cash Flows for the year ended December 31, 2023. The following table presents selected financial information regarding cash flows of the discontinued operations that are included within Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2022 and 2021.

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

	For the Years Ended December 31,	
	2022	2021
Non-cash items included in net income from discontinued operations:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	$ 207	$ 4,540
Asset impairments	—	545
Loss (gain) on sales of assets and businesses	9	(201)
Deferred income taxes and amortization of investment tax credits	(143)	(224)
Net fair value changes related to derivatives	(59)	(568)
Net realized and unrealized losses (gains) on NDT fund investments	205	(586)
Net unrealized losses on equity investments	16	160
Other decommissioning-related activity	36	(946)
Cash flows from investing activities:		
Capital expenditures	(227)	(1,341)
Collection of DPP	169	3,902
Supplemental cash flow information:		
(Decrease) increase in capital expenditures not paid	$ (128)	$ 96
Increase in DPP	348	3,652
Increase in PP&E related to ARO update	335	618

3. 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 2023.

Completed Distribution Base Rate Case Proceedings

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

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	April 15, 2022[(a)]	Electric	$ 199	$ 199	7.85%	November 17, 2022	January 1, 2023
	January 17, 2023[(b)]	Electric	$ 1,487	$ 501	8.905%	December 14, 2023	January 1, 2024
	April 21, 2023[(c)]	Electric	$ 247	$ 259	8.91%	November 30, 2023	January 1, 2024
PECO - Pennsylvania	March 31, 2022	Natural Gas	$ 82	$ 55	N/A[(d)]	October 27, 2022	January 1, 2023
BGE - Maryland	May 15, 2020 (amended September 11, 2020)[(e)]	Electric	$ 203	$ 140	9.50%	December 16, 2020	January 1, 2021
		Natural Gas	$ 108	$ 74	9.65%		
	February 17, 2023[(f)]	Electric	$ 313	$ 179	9.50%	December 14, 2023	January 1, 2024
		Natural Gas	$ 289	$ 229	9.45%		
Pepco - Maryland[(g)]	October 26, 2020 (amended March 31, 2021)	Electric	$ 104	$ 52	9.55%	June 28, 2021	June 28, 2021
DPL - Maryland[(h)]	May 19, 2022	Electric	$ 38	$ 29	9.60%	December 14, 2022	January 1, 2023
ACE - New Jersey[(i)]	February 15, 2023 (amended August 21, 2023)	Electric	$ 92	$ 45	9.60%	November 17, 2023	December 1, 2023

(a) ComEd's 2023 approved revenue requirement above reflects an increase of $144 million for the initial year revenue requirement for 2023 and an increase of $55 million related to the annual reconciliation for 2021. The revenue requirement for 2023 provides for a weighted average debt and equity return on distribution rate base of 5.94% inclusive of an allowed ROE of 7.85%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The reconciliation revenue requirement for 2021 provides for a weighted average debt and equity return on distribution rate base of 5.91%, inclusive of an allowed ROE of 7.78%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points less a performance metrics penalty of 7 basis points. ComEd's last performance-based electric distribution formula rate update filing under EIMA was completed in 2022. See discussion of CEJA below for details on the transition away from the electric distribution formula rate.

(b) Reflects a four-year cumulative multi-year rate plan for January 1, 2024 to December 31, 2027. On December 14, 2023, the ICC approved year-over-year distribution revenue requirement increases in 2024-2027, with an amendatory order on January 10, 2024, of approximately $451 million effective January 1, 2024, $14 million effective January 1, 2025, $6 million effective January 1, 2026, and $30 million effective January 1, 2027, based on an ROE of 8.905%, an equity ratio of 50%, and year end 2022 rate base. The ICC rejected ComEd's Grid Plan, requiring ComEd to file a revised Grid Plan by March 13, 2024, 90 days after the issuance of the December final order. The ICC also directed that the revised Grid Plan would be reviewed through further formal proceedings in that docket. On January 10, 2024, the ICC granted one portion of ComEd's application for rehearing of the December 14, 2023 final order, and directing that a 150-day rehearing process reconsider the revenue requirements for the test years (2024-2027), absent an approved Grid Plan. On January 31,2024, the ICC further clarified the scope of the rehearing process. ComEd anticipates that the revenue requirements determined during the rehearing process will be further updated upon approval of a revised Grid Plan. On January 10, 2024, ComEd also filed with the Illinois appellate court an appeal of various aspects of the ICC's final order on which rehearing was denied, including the 8.905% ROE, 50% equity ratio, and denial of any return on ComEd's pension asset.

(c) On November 30, 2023, the Delivery Reconciliation Amount for 2022 defined in Rider Delivery Service Pricing Reconciliation (Rider DSPR) was approved. The delivery reconciliation amount allows for the reconciliation of the revenue requirement in effect in the final years in which formula rates are determined and until such time as new rates are established under ComEd's approved MRP. The 2023 filing reconciled the delivery service rates in effect in 2022 with the actual delivery service costs incurred in 2022. The reconciliation revenue requirement provides for a weighted average debt and equity return on distribution rate base of 6.48%, inclusive of an allowed ROE of 8.91%, reflecting the monthly yields on 30-year treasury bonds plus 580 basis points.
(d) The PECO electric and natural gas base rate case proceedings were resolved through settlement agreements, which did not specify an approved ROE.
(e) Reflects a three-year cumulative multi-year plan for 2021 through 2023. BGE proposed to use certain tax benefits to fully offset the increases in 2021 and 2022 and partially offset the increase in 2023. The MDPSC awarded BGE electric revenue requirement increases of $59 million, $39 million, and $42 million, before offsets, in 2021, 2022, and 2023, respectively, and natural gas revenue requirement increases of $53 million, $11 million, and $10 million, before offsets, in 2021, 2022, and 2023, respectively. However, the MDPSC utilized the tax benefits to fully offset the increases in 2021 and January 2022 such that customer rates remained unchanged. For the remainder of 2022, the MDPSC chose to offset only 25% of the cumulative 2021 and 2022 electric revenue requirement increases and 50% of the cumulative gas revenue requirement increases. In 2021, the MDPSC deferred a decision on whether to use certain tax benefits to offset the revenue requirement increases in 2023 and directed BGE to make another proposal at the end of 2022. In September 2022, BGE proposed that tax benefits not be used to offset the 2023 revenue requirement increases. On October 26, 2022, the MDPSC accepted BGE's recommendation to not use tax benefits to offset the 2023 revenue requirement increases.
(f) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026. The MDPSC awarded BGE electric revenue requirement increases of $41 million, $113 million, and $25 million in 2024, 2025, and 2026, respectively, and natural gas revenue requirement increases of $126 million, $62 million, and $41 million in 2024, 2025, and 2026, respectively. 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 will be recovered through separate electric and gas riders starting in 2024. As such, the reconciliation amounts are not included in the approved revenue requirement 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.
(g) Reflects a three-year cumulative multi-year plan for April 1, 2021 through March 31, 2024. The MDPSC awarded Pepco electric incremental revenue requirement increases of $21 million, $16 million, and $15 million, before offsets, for the 12-month periods ending March 31, 2022, 2023, and 2024, respectively. Pepco proposed to utilize certain tax benefits to fully offset the increase through 2023 and partially offset customer rate increases in 2024. However, the MDPSC only utilized the acceleration of refunds for certain tax benefits to fully offset the increases such that customer rates remain unchanged through March 31, 2022. On February 23, 2022, the MDPSC chose to offset 25% of the cumulative revenue requirement increase through March 31, 2023. In 2021, the MDPSC deferred a decision on whether to use certain tax benefits to offset the revenue requirement increases for the 12-month period ending March 31, 2024. In December 2022 Pepco proposed that tax benefits not be used to offset the revenue requirement increases for this period. On January 25, 2023, the MDPSC accepted Pepco's recommendations not to use tax benefits to offset revenue requirement increases for the 12-month period ending March 31, 2024.
(h) Reflects a three-year cumulative multi-year plan for January 1, 2023 through December 31, 2025. The MDPSC awarded DPL electric incremental revenue requirement increases of $17 million, $6 million, and $6 million for 2023, 2024, and 2025, respectively.
(i) Requested and approved increases are before New Jersey sales and use tax. The NJBPU awarded ACE electric revenue requirement increases of $36 million and $9 million effective December 1, 2023 and February 1, 2024, respectively.

(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 - District of Columbia[(a)]	April 13, 2023	Electric	$ 191	10.50%	Third quarter of 2024
Pepco - Maryland[(b)]	May 16, 2023 (amended January 26, 2024)	Electric	$ 188	10.50%	Second quarter of 2024
DPL - Delaware[(c)]	December 15, 2022 (amended September 29, 2023)	Electric	$ 39	10.50%	Second quarter of 2024

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(a) Reflects a three-year cumulative multi-year plan for January 1, 2024 through December 31, 2026 submitted to the DCPSC. Pepco requested total electric revenue requirement increases of $117 million, $37 million, and $37 million in 2024, 2025 and 2026, respectively. Requested revenue requirement increases will be used to recover capital investments designed to advance system-readiness and support the District of Columbia's climate and clean energy goals.
(b) Reflects a three-year cumulative multi-year plan for April 1, 2024 through March 31, 2027 submitted to the MDPSC. Pepco requested total electric revenue requirement increases of $69 million, $54 million and $51 million effective April 1, 2024, April 1, 2025, and April 1, 2026, respectively through its rebuttal filing made on January 26, 2024. The plan contains a proposed nine-month extension period with a requested revenue requirement increase of $14 million effective April 1, 2027 through December 31, 2027. Requested revenue requirement increases will be used to recover capital investments designed to advance system-readiness and support Maryland's climate and clean energy goals. On August 7, 2023, the MDPSC issued an order approving a settlement agreement which allows Pepco to establish a revenue deferral mechanism to recover its full Commission-authorized year 1 increase between July 1, 2024 through March 31, 2025 and extend the procedural schedule to address intervenor resource constraints.
(c) The rates went into effect on July 15, 2023, subject to refund.

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).

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

For 2023, the following total increases/(decreases) were included in the Utility Registrants' electric transmission formula rate updates:

Registrant[(a)]	Initial Revenue Requirement Increase	Annual Reconciliation Increase (Decrease)	Total Revenue Requirement Increase	Allowed Return on Rate Base[(b)]	Allowed ROE[(c)]
ComEd	$ 20	$ 63	$ 83	8.09 %	11.50 %
PECO	$ 24	$ 23	$ 47	7.41 %	10.35 %
BGE	$ 19	$ (12)	$ 4 [(d)]	7.34 %	10.50 %
Pepco	$ 37	$ (5)	$ 32	7.57 %	10.50 %
DPL	$ 32	$ (3)	$ 29	7.08 %	10.50 %
ACE	$ 41	$ (12)	$ 29	7.08 %	10.50 %

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(a) All rates are effective June 1, 2023 - May 31, 2024, subject to review by interested parties pursuant to review protocols of each Utility Registrants' tariff.
(b) Represents the weighted average debt and equity return on transmission rate bases. For ComEd and PECO, the common equity component of the ratio used to calculate the weighted average debt and equity return on the transmission formula rate base is currently capped at 55% and 55.75%, respectively.
(c) The rate of return on common equity for each Utility Registrant includes a 50-basis-point incentive adder for being a member of a RTO.
(d) The increase in BGE's transmission revenue requirement includes a $3 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

ComEd filed, and received approval for, its last performance-based electric distribution formula rate update under EIMA in 2022; those rates were in effect throughout 2023.

On February 3, 2022, the ICC approved a tariff that establishes the process under which ComEd reconciled its 2022 and will reconcile its 2023 rate year revenue requirements with actual costs. Those reconciliation amounts are determined using the same process used for prior reconciliations under the performance-based electric distribution formula rate. Using that process, for the rate years 2022 and 2023 ComEd will ultimately collect revenues from customers reflecting each year's actual recoverable costs, year-end rate base, and a weighted average debt and equity return on distribution rate base, with the ROE component based on the annual average of the monthly yields of the 30-year U.S. Treasury bonds plus 580 basis points. In April 2023, ComEd filed its first petition with the ICC to reconcile its 2022 actual costs with the approved revenue requirement that was in effect in 2022; the final order was issued on November 30, 2023, for rates beginning January 2024. In 2024, ComEd will file with the ICC its 2023 actual costs with the approved revenue requirement that was in effect in 2023.

Beginning in 2024, ComEd will recover 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 (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 May 22, 2023, direct testimony was filed by ICC staff and more than a dozen intervenors and intervenor groups. The testimonies addressed a wide variety of topics, including rate of return on equity, capital structure, grid planning, various distribution grid and information technology investments, and affordability and customer service. ComEd also made voluntary adjustments and, per the ICC's final beneficial electrification order requiring ComEd to recover beneficial electrification costs through the MRP, increased its total revenue requirement request from $1.472 billion to $1.545 billion. ComEd filed its reply brief on September 27, 2023, to adjust its total requested revenue requirement increase to $1.487 billion.

On December 14, 2023, the ICC issued a final order. The ICC rejected ComEd's Grid Plan as non-compliant with certain requirements of CEJA, and required ComEd to file a revised Grid Plan by March 13, 2024, 90 days after the issuance of the final order. In the absence of an approved Grid Plan, the ICC set ComEd's forecast revenue requirements for 2024-2027 based on ComEd's approved year-end 2022 rate base. This results in a total cumulative revenue requirement increase of $501 million, a $986 million total revenue reduction from the requested cumulative revenue requirement increase but remains subject to annual reconciliation in accordance with CEJA. The final order approved the process and formulas associated with the MRP reconciliation mechanisms. The ICC did not approve a previously proposed phase-in of the ICC's approved year-over-year revenue increases, and it 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 January 31, 2024, the ICC granted ComEd's motion seeking additional clarification on the scope on rehearing, generally accepting ComEd's proposal and confirming that the rehearing will determine if the forecasted year-end 2023 rate base should be used to set rates for 2024 through 2027 until a refiled Grid Plan is approved. A final rehearing order on that topic is statutorily required by early June 2024. On January 10, 2024, ComEd also filed an appeal in the Illinois Appellate Court of the issues on which rehearing was denied, including but not limited to the allowed ROE and denial of a return on ComEd's pension asset. There is no deadline by when the appellate court must rule. On February 8, 2024, the ICC denied ComEd's request to provide clarification on other issues including the schedule for review of the refiled Grid Plan. ComEd has completed and placed in service additional utility plant assets in 2023 and will continue to complete and place in service additional utility plant assets prior to the approval of the new Grid Plan. There are still significant unknowns, but ComEd does not currently believe that it is probable that the initially uncollected depreciation or return on the recently completed plant will ultimately be disallowed.

In January 2022, ComEd filed a request with the ICC proposing performance metrics that would be used in determining ROE incentives and penalties in the event ComEd filed a MRP in January 2023. On September 27, 2022, the ICC issued a final order approving seven performance metrics that provide symmetrical performance adjustments of 32 total basis points to ComEd's rate of return on common equity based on the extent to which ComEd achieves the annual performance goals. On November 10, 2022, the ICC granted ComEd's application for rehearing, in part. On April 5, 2023, the ICC issued its final order on rehearing for the performance and tracking metrics proceeding, in which the ICC declined to adopt ComEd's proposed modifications to the reliability and peak load reduction performance metrics. Efforts are underway to implement the performance metrics, which took effect on January 1, 2024. ComEd will make its initial filing in 2025 to assess performance achieved under the metrics in 2024, and to determine any ROE adjustment, which would take effect in 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-powered 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. 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. In the June 2022 billing period. ComEd began issuing credits to its retail customers under its new CMC rider. A regulatory asset is recorded for the difference between customer credits issued and the credit to be received from the participating nuclear-powered generating facilities. The balance as of December 31, 2023 is $673 million.

Under CEJA, the costs of procuring CMCs, including carrying costs, are recovered through a rider, the Rider Carbon-Free Resource Adjustment (Rider CFRA). As originally approved by the ICC, Rider CFRA provides for an annual reconciliation and true-up to actual costs incurred or credits received by ComEd to purchase CMCs, with any difference to be credited to or collected from ComEd’s retail customers in subsequent periods. The difference between the net payments to (or receivables from) ComEd ratepayers and the credits received by ComEd to purchase CMCs is recorded to Purchased power expense with an offset to the regulatory asset (or regulatory liability). On December 21, 2022, ComEd filed an amendment to Rider CFRA proposing that it recover costs or provide credits faster than the tariff allows, implement monthly reconciliations, and allow ComEd to adjust Rider CFRA rates based not only on anticipated differences but also past payments or credits, and implement monthly reconciliations beginning with the June 2023 delivery period. The ICC approved the proposal on January 19, 2023. In addition, on March 24, 2023, ComEd submitted revisions to Rider CFRA which clarified the methodology for calculating interest to be included in the annual reconciliation associated with the June 2022 through May 2023 delivery year. The ICC approved the proposal on April 20, 2023. 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 CMCs during the delivery year beginning June 1, 2022 and extending through May 31, 2023.

Excess Deferred Income Taxes

The ICC initiated a docket to accelerate and fully credit to customers TCJA unprotected property-related EDIT no later than December 31, 2025. On July 7, 2022, the ICC issued a final order on the schedule for the acceleration of EDIT amortization, adopting the proposal as submitted by several parties, including ComEd, ICC Staff, the Illinois Attorney General's Office, and the Citizens Utility Board. EDIT amortization will be credited to customers through a new rider from January 1, 2023 through December 31, 2025.

Beneficial Electrification Plan

On March 23, 2023, the ICC issued its final order approving the beneficial electrification plan for ComEd. The ICC rejected ComEd's request to treat a large portion of beneficial electrification costs as a regulatory asset and ordered ComEd to seek cost recovery through the multi-year rate plan filing for 2024 and 2025, and the final formula rate reconciliation docket for 2023, rather than through a separate charge. The order also authorized an overall annual budget of $77 million per year for the three year plan period (2023 through 2025), with flexibility to roll forward unused funds to future years within the same plan period. On April 18, 2023, ComEd filed an application for rehearing in the beneficial electrification plan docket. The Chicago Transit Authority and City of Chicago, jointly, and the Office of the Illinois Attorney General (ILAG) also filed applications for rehearing. On April 27, 2023, ICC staff filed a motion for clarification, seeking clarification from the ICC on the precise budget described in the final order. On May 8, 2023, the ICC denied all applications for rehearing, and entered an amendatory order regarding the annual beneficial electrification plan budgets. ComEd has been directed to use good faith efforts to spend $77 million annually. ComEd subsequently filed its compliance filing in May 2023, detailing project related spending, clarifying the procedure that will be used to seek stakeholder feedback related to beneficial electrification pilot programs, and including the timeline for tariff changes required to implement the programs. ComEd and the ILAG both filed appeals of the ICC's interim order that addressed the permissible scope of utility beneficial electrification programs outside of transportation and the rate impact cap. The ILAG also filed an appeal seeking reversal of portions of the ICC's final decision. The final order partly mooted ComEd's appeal of the interim order and ComEd has decided not to pursue the other issues. As such, ComEd moved to voluntarily dismiss its appeal and the appellate court granted that request. The ILAG consolidated their appeals. Any ruling on the appeals, even a negative ruling removing programs from the BE Plan or lowering the overall budget of the BE Plan, will only impact forward-looking costs.

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 in 2023 through 2040 to achieve these energy efficiency MWh savings goals, which will be deferred as a separate regulatory asset that will be 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 the electric distribution formula rate) 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 its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Beginning January 1, 2018, 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 current 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 similar to those in ComEd's electric distribution formula rate.

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

During 2023, 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 26, 2023	$ 118	$ 118	8.91 %	November 30, 2023	January 1, 2024

(a) ComEd's 2024 approved revenue requirement above reflects an increase of $71 million for the initial year revenue requirement for 2024 and a increase of $47 million related to the annual reconciliation for 2022. The revenue requirement for 2024 provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 6.48% inclusive of an allowed ROE of 8.91%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. The revenue requirement for the 2022 reconciliation year provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 7.47% inclusive of an allowed ROE of 10.89%, 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 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.

Maryland Order Directing the Distribution of Energy Assistance Funds (Exelon, BGE, PHI, Pepco, and DPL). On June 15, 2021, the MDPSC issued an order authorizing the disbursal of funds to utilities in accordance with Maryland COVID-19 relief legislation. Under this order, BGE, Pepco, and DPL received funds of $50 million, $12 million, and $8 million, respectively, in July 2021. The funds have been used to reduce or eliminate certain qualifying past-due residential customer receivables.

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 will begin deferring less energy efficiency and demand response program costs to a regulatory asset. 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.

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 impacted by abnormal weather or usage per customer. 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 distribution at Pepco District of Columbia are, however, 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 was required seeking 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 will no longer be impacted by abnormal weather or usage for most customers. Starting in third quarter of 2021, ACE has recorded 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 with the NJBPU a petition 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, which is to be paid by the end of 2024, and recognized a corresponding regulatory asset of $203 million.

As of December 31, 2023, the $49 million liability for the contract termination fee is included in Other current liabilities in Exelon's Consolidated Balance Sheet and PPA termination obligation in PHI's and ACE's Consolidated Balance Sheets. For the year ended December 31, 2023 and 2022, ACE has paid $88 million and $66 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 February 28, 2018, ACE filed with the NJBPU the Registrants' IIP proposing to seek recovery of a series of investments through a new rider mechanism, totaling $338 million, between 2019-2022 to provide safe and reliable service for its customers. The IIP will allow for more timely recovery of investments made to modernize and enhance ACE's electric system. On April 15, 2019, ACE entered into a settlement agreement with other parties, which allows for a recovery totaling $96 million of reliability related capital investments from July 1, 2019 through June 30, 2023. On April 18, 2019, the NJBPU approved the settlement agreement.

On October 31, 2022, ACE filed with the NJBPU a second 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 was required seeking 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 involves 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 addresses all material aspects of ACE's smart energy network deployment plan, including cost recovery of the investment costs, incremental O&M 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.

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 extends back to January 1, 2017. During the first quarter of 2023, ComEd was provided with information from FERC about several potential findings, including ComEd's methodology regarding the allocation of certain overhead costs to capital under FERC regulations. Based on the preliminary findings and discussions with FERC staff, ComEd determined that a loss was probable and recorded a regulatory liability to reflect its best estimate of that loss in the first quarter of 2023.

On July 27, 2023, FERC issued 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 August 28, 2023, ComEd filed a formal notice of the issues it will contest. On December 14, 2023, FERC appointed a settlement judge for the contested overhead allocation findings. The final outcome and resolution of any contested audit issues as well as a reasonable estimate of potential future losses cannot be accurately estimated at this stage; however, the final resolution of these matters could result in recognition of future losses, above the amounts currently accrued, that could be material to the Exelon and ComEd financial statements.

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, 2023 and 2022:

December 31, 2023	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory assets								
AMI programs - deployment costs	$ 109	$ —	$ —	$ 49	$ 60	$ 18	$ 17	$ 25
AMI programs - legacy meters	127	28	—	12	87	41	14	32
Asset retirement obligations	159	104	22	23	10	6	2	2
Carbon mitigation credit	673	673	—	—	—	—	—	—
COVID-19	41	11	11	6	13	10	3	—
DC PLUG charge	3	—	—	—	3	3	—	—
Deferred income taxes	759	—	748	—	11	11	—	—
Deferred storm costs	114	—	—	84	30	9	2	19
Electric distribution formula rate annual reconciliations	787	787	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	89	89	—	—	—	—	—	—
Electric energy and natural gas costs	98	—	1	25	72	11	2	59
Energy efficiency and demand response programs	631	—	23	316	292	187	73	32
Energy efficiency costs	1,691	1,691	—	—	—	—	—	—
Fair value of long-term debt	486	—	—	—	385	—	—	—
Fair value of PHI's unamortized energy contracts	35	—	—	—	35	—	—	—
MGP remediation costs	315	286	15	14	—	—	—	—
Multi-year plan reconciliations	112	—	—	112	—	—	—	—
Pension and OPEB	2,254	—	—	—	—	—	—	—
Pension and OPEB - merger related	637	—	—	—	—	—	—	—
Removal costs	827	—	—	219	608	137	118	354
Renewable energy	134	134	—	—	—	—	—	—
Transmission formula rate annual reconciliations	75	—	9	5	61	15	22	24
Under-recovered credit loss expense	112	78	—	—	34	—	—	34
Under-recovered revenue decoupling	176	—	—	64	112	100	—	12
Universal service fund charge under-recovery - Electric	59	—	59	—	—	—	—	—
Zero emission credit	58	58	—	—	—	—	—	—
Other	352	190	32	27	111	52	19	15
Total regulatory assets	10,913	4,129	920	956	1,924	600	272	608
Less: current portion	2,215	1,335	127	229	337	150	54	125
Total noncurrent regulatory assets	$ 8,698	$ 2,794	$ 793	$ 727	$ 1,587	$ 450	$ 218	$ 483

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

December 31, 2023	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Decommissioning the Regulatory Agreement Units	$ 3,232	$ 2,954	$ 278	$ —	$ —	$ —	$ —	$ —
Dedicated facilities charge	129	—	—	129	—	—	—	—
Deferred income taxes	3,284	1,900	—	634	750	338	274	138
Electric energy and natural gas costs	121	4	93	—	24	9	15	—
Energy efficiency and demand response programs	1	—	1	—	—	—	—	—
Multi-year plan reconciliations	23	—	—	—	23	16	7	—
Over-recovered revenue decoupling	2	—	—	—	2	—	2	—
Removal costs	1,845	1,701	—	28	116	20	96	—
Renewable portfolio standards costs	1,102	1,102	—	—	—	—	—	—
Other	226	23	34	9	60	14	21	8
Total regulatory liabilities	9,965	7,684	406	800	975	397	415	146
Less: current portion	389	191	92	27	71	15	50	6
Total noncurrent regulatory liabilities	$ 9,576	$ 7,493	$ 314	$ 773	$ 904	$ 382	$ 365	$ 140

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

December 31, 2022	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
AMI programs - deployment costs	$ 122	$ —	$ —	$ 69	$ 53	$ 25	$ 22	$ 6
AMI programs - legacy meters	160	48	—	20	92	53	17	22
Asset retirement obligations	151	99	22	21	9	6	2	1
Carbon mitigation credit	843	843	—	—	—	—	—	—
COVID-19	58	20	17	8	13	10	3	—
DC PLUG charge	37	—	—	—	37	37	—	—
Deferred income taxes	606	—	595	—	11	11	—	—
Deferred storm costs	90	—	—	55	35	2	2	31
Electric distribution formula rate annual reconciliations	271	271	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	115	115	—	—	—	—	—	—
Electric energy and natural gas costs	241	—	15	25	201	41	26	134
Energy efficiency and demand response programs	560	—	—	286	274	187	74	13
Energy efficiency costs	1,434	1,434	—	—	—	—	—	—
Fair value of long-term debt	521	—	—	—	414	—	—	—
Fair value of PHI's unamortized energy contracts	44	—	—	—	44	—	—	—
MGP remediation costs	318	293	13	12	—	—	—	—
Pension and OPEB	1,867	—	—	—	—	—	—	—
Pension and OPEB - merger related	769	—	—	—	—	—	—	—
Removal costs	782	—	—	171	611	144	109	359
Renewable energy	85	85	—	—	—	—	—	—
Transmission formula rate annual reconciliations	37	—	16	—	21	3	5	13
Under-recovered credit loss expense	71	38	—	—	33	—	—	33
Under-recovered revenue decoupling	106	—	—	8	98	98	—	—
Universal service fund charge under-recovery - Electric	19	—	19	—	—	—	—	—
Other	371	196	35	29	119	55	22	12
Total regulatory assets	9,678	3,442	732	704	2,065	672	282	624
Less: current portion	1,641	775	80	177	455	235	80	130
Total noncurrent regulatory assets	$ 8,037	$ 2,667	$ 652	$ 527	$ 1,610	$ 437	$ 202	$ 494

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

December 31, 2022	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Decommissioning the Regulatory Agreement Units	$ 2,897	$ 2,660	$ 237	$ —	$ —	$ —	$ —	$ —
Dedicated facilities charge	110	—	—	110	—	—	—	—
Deferred income taxes	3,546	2,010	—	682	854	402	304	148
Electric energy and natural gas costs	87	11	65	4	7	—	7	—
Energy efficiency and demand response programs	15	—	15	—	—	—	—	—
Multi-year plan reconciliations	14	—	—	—	14	14	—	—
Over-recovered revenue decoupling	19	—	—	4	15	—	6	9
Removal costs	1,750	1,604	—	35	111	20	91	—
Renewable portfolio standards costs	810	810	—	—	—	—	—	—
Stranded costs	9	—	—	—	9	—	—	9
Transmission formula rate annual reconciliations	31	3	—	18	10	9	1	—
Other	261	41	28	10	67	16	15	16
Total regulatory liabilities	9,549	7,139	345	863	1,087	461	424	182
Less: current portion	437	226	75	47	76	6	44	26
Total noncurrent regulatory liabilities	$ 9,112	$ 6,913	$ 270	$ 816	$ 1,011	$ 455	$ 380	$ 156

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 - 2029	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 - To be determined in next distribution rate case filed with NJBPU.	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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
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.	2024	No
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.	ComEd - 2025 BGE - 2028 PECO - 2024 Pepco (District of Columbia) - $8 million to be determined in pending multi-year plan filed with DCPSC. Pepco (Maryland) - $2 million to be determined in pending multi-year plan filed with MDPSC. DPL (Maryland) - $1 million - 2027 DPL (Delaware) - $2 million to be determined in pending distribution rate case filed with DEPSC.	ComEd, BGE, and DPL (Maryland) - Yes PECO, Pepco, and DPL (Delaware) - No
DC PLUG charge	Represents costs associated with DC PLUG, which is a projected six-year, $500 million project to place underground some of the District of Columbia's most outage-prone power lines with $250 million of the project costs funded by Pepco and $250 million funded by the District of Columbia. Rates for the DC PLUG initiative went into effect on February 7, 2018.	2024	Portion of asset funded by Pepco-Yes
Decommissioning the Regulatory 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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
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
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, and BGE, amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland and New Jersey jurisdictions.	Pepco - $1 million - 2024; $8 million to be determined in a future multi-year plan filed with MDPSC. DPL - 2027 ACE - 2026 BGE - $57 million - 2028; $27 million to be determined in the next multi-year plan filed with MDPSC.	Pepco, DPL, BGE - Yes ACE - No
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 is updated annually with rates effective on January 1st.	2025	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.	2027	Yes

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Electric energy and natural gas costs	Represents under (over)-recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	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 DPL (Delaware), Pepco (District of Columbia) - No 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.	2035	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 $101 million and $385 million, respectively, as of December 31, 2023, and $107 million and $414 million, respectively, as of December 31, 2022, 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
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 18 — 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.	BGE - $60 million related to 2021 and 2022 reconciliations - 2025. $52 million related to 2023 reconciliations - to be determined in a future MDPSC order. Pepco (District of Columbia) - $16 million which has been reviewed by the DCPSC and will be finalized upon receipt of the DCPSC order in the pending multi-year plan filing. DPL (Maryland) - $7 million to be determined in next multi-year plan filed with MDPSC.	BGE - No Pepco (District of Columbia) - Yes DPL (Maryland) - Yes

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 14 — Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	No

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

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
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 14 — 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, and DPL - 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
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.	$1,033 million to be determined in pending ICC annual reconciliation for the Renewable Energy Adjustment rider. $69 million to be determined based on the LTRRPP developed by the IPA.	No
Stranded costs	Represents overcollection of a customer surcharge collected by ACE to fund principal and interest payments on Transition Bonds of ACE Transition Funding that securitized such costs.	2023	No

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
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.	2025	Yes
Under (over) -recovered revenue decoupling	Represents electric and / or gas distribution costs recoverable from or refundable to customers under decoupling mechanisms.	BGE - 2025 Pepco (Maryland) - $10 million - 2024 Pepco (District of Columbia) - $90 million to be determined in the next multi-year plan filed with DCPSC. DPL - 2024 ACE - 2024	BGE, Pepco, DPL, ACE - No
Under-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 June through May of each respective year, subject to approval of the NJBPU.	ComEd - 2024 ACE - To be determined in pending 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
Zero emission credit	Represents ZEC procurement costs and any reasonable costs ComEd has incurred to implement and comply with the ZEC procurement process.	ComEd - Over 9 months starting with the September billing period and ending with the following May billing period.	ComEd - 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 prior to separation on February 1, 2022 were generally offset in Exelon's Consolidated

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

Statements of Operations and Comprehensive Income with an offsetting adjustment to the regulatory liabilities or regulatory assets and an equal noncurrent affiliate receivable from or payable to Generation at PECO. Following the separation, 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 prior to separation on February 1, 2022 were offset in the Consolidated Statements of Operations and Comprehensive Income with an offsetting adjustment to regulatory liabilities and noncurrent affiliate receivable from Generation at ComEd. Following the separation, 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.

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, 2023 and December 31, 2022

	Exelon	ComEd[(a)]	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE[(d)]
December 31, 2023	$ 110	$ 32	$ 33	$ 45	$ 34	$ 1	$ 10
December 31, 2022	57	8	28	21	18	2	1

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its energy efficiency and electric distribution formula rate regulatory assets.
(b) BGE's amount capitalized for ratemaking purposes primarily relates to earnings on shareholders' investment on their AMI programs and on investments in rate base included in the multi-year plan reconciliations.
(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI programs and Energy efficiency and demand response programs, and for Pepco District of Columbia revenue decoupling program. The earnings on energy efficiency are on Pepco District of Columbia and DPL Delaware programs only.
(d) ACE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on AMI programs.

4. 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.

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(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.

On July 1, 2020, Pepco, DPL, and ACE each entered into a collaborative arrangement ("Agreement") with an unrelated owner and manager of communication infrastructure (the "Buyer"). Under this arrangement, Pepco, DPL, and ACE sold a 60% undivided interest in their respective portfolios of transmission tower attachment agreements with telecommunications companies to the Buyer, in addition to transitioning management of the day-to-day operations of the jointly-owned agreements to the Buyer for 35 years, while retaining the safe and reliable operation of its utility assets. In return, Pepco, DPL, and ACE will provide the Buyer limited access on the portion of the towers where the equipment resides for the purposes of managing the agreements for the benefit of Pepco, DPL, ACE, and the Buyer. Pursuant to the Agreement, Pepco, DPL, and ACE have the option ("Payment Option"), but not obligation, to sell two additional 10% undivided interests in the tower attachment agreements to the Buyer for specified consideration. In addition, for an initial period of three years and two, two-year extensions that are subject to certain conditions, the Buyer has the exclusive right to enter into new agreements with telecommunications companies and to receive a specified undivided percentage interest in those new agreements as set forth in the Agreement. Pepco, DPL, and ACE received cash and recorded contract liabilities as of July 1, 2020. The revenue attributable to this arrangement will be recognized as Electric operating revenues over the 35 years under the Agreement.

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

During the fourth quarter of 2023, Pepco, DPL, and ACE entered into an amendment to the Agreement (“Amendment”) to modify the terms of the Payment Option and the conditions to exercise the exclusive right extensions. Concurrently, Pepco, DPL and ACE exercised both Payment Options which also triggered the extension of the exclusive right period until 2027. The Amendment and executed Payment Options represent a contract modification that is accounted for prospectively in accordance with authoritative guidance. Pepco, DPL and ACE received cash and recorded an increase to the contract liabilities as of December 31, 2023 as shown in the table below. The revenue will be recognized as Electric operating revenues over the remaining term of the Agreement (approximately 31 years).

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, 2023, 2022, and 2021, 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, 2021	$ 109	$ 109	$ 87	$ 11	$ 11
Revenues recognized	(8)	(8)	(6)	(1)	(1)
Balance at December 31, 2022	$ 101	$ 101	$ 81	$ 10	$ 10
Consideration received	39	39	31	4	4
Revenues recognized	(7)	(7)	(5)	(1)	(1)
Balance at December 31, 2023	$ 133	$ 133	$ 107	$ 13	$ 13

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(a) Revenues recognized in the years ended December 31, 2023 and 2022, were included in the contract liabilities at December 31, 2022 and 2021, 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, 2023. 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
2024	$ 8	$ 8	$ 6	$ 1	$ 1
2025	6	6	5	—	1
2026	6	6	5	—	1
2027	5	5	5	—	—
2028 and thereafter	108	108	86	12	10
Total	$ 133	$ 133	$ 107	$ 13	$ 13

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 5 — Segment Information for the presentation of the Registrant's revenue disaggregation.

5. 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.

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 evaluate the performance of and allocate resources to the segments based on net income.

The separation of Constellation Energy Corporation, including Generation and its subsidiaries, meets the criteria for discontinued operations and as such, results of operations are presented as discontinued operations and have been excluded from continuing operations for all periods presented. Furthermore, the reportable segment information related to the discontinued operations has been excluded from the tables presented below. See Note 2 — Discontinued Operations for additional information.

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, 2023, 2022, and 2021 is as follows:

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

	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Operating revenues[b]:							
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
2022							
Electric revenues	$ 5,761	$ 3,165	$ 2,871	$ 5,317	$ —	$ (31)	$ 17,083
Natural gas revenues	—	738	1,024	238	—	(5)	1,995
Shared service and other revenues	—	—	—	10	1,823	(1,833)	—
Total operating revenues	$ 5,761	$ 3,903	$ 3,895	$ 5,565	$ 1,823	$ (1,869)	$ 19,078
2021							
Electric revenues	$ 6,406	$ 2,659	$ 2,505	$ 4,860	$ —	$ (35)	$ 16,395
Natural gas revenues	—	539	836	168	—	—	1,543
Shared service and other revenues	—	—	—	13	2,213	(2,226)	—
Total operating revenues	$ 6,406	$ 3,198	$ 3,341	$ 5,041	$ 2,213	$ (2,261)	$ 17,938
Intersegment revenues[c]:							
2023	$ 16	$ 9	$ 9	$ 9	$ 1,750	$ (1,793)	$ —
2022	16	7	15	10	1,823	(1,865)	6
2021	41	21	31	13	2,203	(2,252)	57
Depreciation and amortization:							
2023	$ 1,403	$ 397	$ 654	$ 990	$ 62	$ —	$ 3,506
2022	1,323	373	630	938	61	—	3,325
2021	1,205	348	591	821	67	1	3,033
Operating expenses:							
2023	$ 6,038	$ 3,146	$ 3,245	$ 5,114	$ 1,991	$ (1,820)	$ 17,714
2022	4,218	3,102	3,376	4,734	2,093	(1,762)	15,761
2021	5,151	2,547	2,860	4,240	2,045	(1,587)	15,256
Interest expense, net:							
2023	$ 477	$ 201	$ 182	$ 323	$ 546	$ —	$ 1,729
2022	414	177	152	292	415	(3)	1,447
2021	389	161	138	267	335	(1)	1,289
Income taxes:							
2023	$ 314	$ 20	$ 133	$ 116	$ (207)	$ (2)	$ 374
2022	264	79	8	9	—	(11)	349
2021	172	12	(35)	42	8	(161)	38
Net income (loss) from continuing operations:							
2023	$ 1,090	$ 563	$ 485	$ 590	$ (380)	$ (20)	$ 2,328
2022	917	576	380	608	(393)	(34)	2,054
2021	742	504	408	561	(156)	(443)	1,616
Capital expenditures:							
2023	$ 2,576	$ 1,426	$ 1,367	$ 1,988	$ 54	$ —	$ 7,411
2022	2,506	1,349	1,262	1,709	95	—	6,921
2021	2,387	1,240	1,226	1,720	67	—	6,640
Total assets:							
2023	$ 42,827	$ 15,595	$ 14,184	$ 26,903	$ 6,374	$ (4,337)	$ 101,546
2022	39,661	14,502	13,350	26,082	6,014	(4,260)	95,349

(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 22 — Supplemental Financial Information for additional information on total utility taxes.
(c) See Note 23 — 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)]:						
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
2022						
Electric revenues	$ 2,531	$ 1,357	$ 1,431	$ —	$ (2)	$ 5,317
Natural gas revenues	—	238	—	—	—	238
Shared service and other revenues	—	—	—	391	(381)	10
Total operating revenues	$ 2,531	$ 1,595	$ 1,431	$ 391	$ (383)	$ 5,565
2021						
Electric revenues	$ 2,274	$ 1,212	$ 1,388	$ —	$ (14)	$ 4,860
Natural gas revenues	—	168	—	—	—	168
Shared service and other revenues	—	—	—	379	(366)	13
Total operating revenues	$ 2,274	$ 1,380	$ 1,388	$ 379	$ (380)	$ 5,041
Intersegment revenues[(c)]:						
2023	$ 9	$ 8	$ 2	$ 422	$ (432)	$ 9
2022	5	6	2	380	(383)	10
2021	5	7	2	380	(381)	13
Depreciation and amortization:						
2023	$ 441	$ 244	$ 283	$ 22	$ —	$ 990
2022	417	232	261	28	—	938
2021	403	210	179	29	—	821
Operating expenses:						
2023	$ 2,377	$ 1,420	$ 1,314	$ 434	$ (431)	$ 5,114
2022	2,140	1,359	1,225	393	(383)	4,734
2021	1,871	1,161	1,201	388	(381)	4,240
Interest expense, net:						
2023	$ 165	$ 74	$ 72	$ 12	$ —	$ 323
2022	150	66	66	9	1	292
2021	140	61	58	8	—	267
Income taxes:						
2023	$ 51	$ 35	$ 36	$ (6)	$ —	$ 116
2022	(9)	14	3	1	—	9
2021	15	42	(13)	(2)	—	42
Net income (loss):						
2023	$ 306	$ 177	$ 120	$ (13)	$ —	$ 590
2022	305	169	148	(14)	—	608
2021	296	128	146	(9)	—	561
Capital expenditures:						
2023	$ 957	$ 562	$ 460	$ 9	$ —	$ 1,988
2022	874	430	398	7	—	1,709
2021	843	429	445	3	—	1,720
Total assets:						
2023	$ 11,194	$ 5,966	$ 5,157	$ 4,627	$ (41)	$ 26,903
2022	10,657	5,802	4,979	4,677	(33)	26,082

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.

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

(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 22 — Supplemental Financial Information for additional information on total utility taxes.
(c) Includes intersegment revenues with ComEd, PECO, and BGE, which are eliminated at Exelon.

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.

	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)

	2022						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Electric revenues							
Residential	$ 3,304	$ 2,026	$ 1,564	$ 2,590	$ 1,076	$ 750	$ 764
Small commercial & industrial	1,173	521	327	607	155	235	217
Large commercial & industrial	5	299	567	1,422	1,083	137	202
Public authorities & electric railroads	29	30	27	64	34	15	15
Other[a]	955	271	398	695	208	227	252
Total electric revenues[b]	$ 5,466	$ 3,147	$ 2,883	$ 5,378	$ 2,556	$ 1,364	$ 1,450
Natural gas revenues							
Residential	$ —	$ 512	$ 678	$ 127	$ —	$ 127	$ —
Small commercial & industrial	—	186	111	55	—	55	—
Large commercial & industrial	—	—	183	12	—	12	—
Transportation	—	26	—	15	—	15	—
Other[c]	—	12	68	29	—	29	—
Total natural gas revenues[d]	$ —	$ 736	$ 1,040	$ 238	$ —	$ 238	$ —
Total revenues from contracts with customers	$ 5,466	$ 3,883	$ 3,923	$ 5,616	$ 2,556	$ 1,602	$ 1,450
Other revenues							
Revenues from alternative revenue programs	$ 267	$ 2	$ (47)	$ (59)	$ (31)	$ (9)	$ (19)
Other electric revenues[e]	28	16	14	8	6	2	—
Other natural gas revenues[e]	—	2	5	—	—	—	—
Total other revenues	$ 295	$ 20	$ (28)	$ (51)	$ (25)	$ (7)	$ (19)
Total revenues for reportable segments	$ 5,761	$ 3,903	$ 3,895	$ 5,565	$ 2,531	$ 1,595	$ 1,431

	2021						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Electric revenues							
Residential	$ 3,233	$ 1,704	$ 1,375	$ 2,441	$ 1,003	$ 694	$ 744
Small commercial & industrial	1,571	422	267	521	135	193	193
Large commercial & industrial	559	243	459	1,123	844	94	185
Public authorities & electric railroads	45	31	27	58	31	14	13
Other[a]	926	229	371	634	205	201	229
Total electric revenues[b]	$ 6,334	$ 2,629	$ 2,499	$ 4,777	$ 2,218	$ 1,196	$ 1,364
Natural gas revenues							
Residential	$ —	$ 372	$ 518	$ 97	$ —	$ 97	$ —
Small commercial & industrial	—	136	83	42	—	42	—
Large commercial & industrial	—	—	147	7	—	7	—
Transportation	—	24	—	14	—	14	—
Other[c]	—	7	68	8	—	8	—
Total natural gas revenues[d]	$ —	$ 539	$ 816	$ 168	$ —	$ 168	$ —
Total revenues from contracts with customers	$ 6,334	$ 3,168	$ 3,315	$ 4,945	$ 2,218	$ 1,364	$ 1,364
Other revenues							
Revenues from alternative revenue programs	$ 42	$ 26	$ 12	$ 91	$ 53	$ 14	$ 24
Other electric revenues[e]	30	4	11	5	3	2	—
Other natural gas revenues[e]	—	—	3	—	—	—	—
Total other revenues	$ 72	$ 30	$ 26	$ 96	$ 56	$ 16	$ 24
Total revenues for reportable segments	$ 6,406	$ 3,198	$ 3,341	$ 5,041	$ 2,274	$ 1,380	$ 1,388

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

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(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates in 2023, 2022, and 2021 respectively of:
- $16 million, $16 million, and $41 million at ComEd
- $7 million, $7 million, and $20 million at PECO
- $6 million, $7 million, and $13 million at BGE
- $9 million, $10 million, and $13 million at PHI
- $9 million, $5 million, and $5 million at Pepco
- $8 million, $6 million, and $7 million at DPL
- $2 million, $2 million, and $2 million at ACE

(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates in 2023, 2022, and 2021 respectively of:
- $2 million, less than $1 million, and $1 million at PECO
- $3 million, $8 million, and $18 million at BGE

(e) Includes late payment charge revenues.

6. 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, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2022	$ 327	$ 59	$ 105	$ 54	$ 109	$ 47	$ 21	$ 41
Plus: Current period provision for expected credit losses[(a)(b)(c)]	170	53	48	26	43	23	9	11
Less: Write-offs[(d)(e)(f)], net of recoveries[(g)]	180	43	58	34	45	18	11	16
Balance at December 31, 2023	$ 317	$ 69	$ 95	$ 46	$ 107	$ 52	$ 19	$ 36

	Year Ended December 31, 2022							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2021	$ 320	$ 73	$ 105	$ 38	$ 104	$ 37	$ 18	$ 49
Plus: Current period provision for expected credit losses	176	29	52	37	58	31	12	15
Less: Write-offs, net of recoveries	169	43	52	21	53	21	9	23
Balance at December 31, 2022	$ 327	$ 59	$ 105	$ 54	$ 109	$ 47	$ 21	$ 41

(a) For ComEd, the change in current period provision for expected credit losses is primarily a result of increased receivable balances.
(b) For BGE, DPL and ACE, the change in current period provision for expected credit losses is primarily a result of decreased receivable balances.
(c) For Pepco the change in current period provision for expected credit losses is primarily a result of receivables increasing at a slower pace versus the prior period.
(d) For PECO and BGE the change in write-offs is primarily a result of increased disconnection activities.
(e) For PHI, ACE, and Pepco, write-offs are primarily attributable to the termination of the moratorium in the service territory for each operating company, which beginning in 2020, prevented customer disconnections for non-payment. Disconnection activities across the service territories resumed from September 2020 through January 2022, resulting in write-offs of aged accounts receivable.
(f) For DPL, the change in write-offs is primarily attributable to unfavorable customer payment behavior.
(g) Recoveries were not material to the Registrants.

The following tables present the rollforward of Allowance for credit losses on Other accounts receivable.

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

	Year Ended December 31, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2022	$ 82	$ 17	$ 9	$ 10	$ 46	$ 25	$ 7	$ 14
Plus: Current period provision for expected credit losses	21	5	4	5	7	3	1	3
Less: Write-offs, net of recoveries[(a)]	21	5	5	8	3	—	—	3
Balance at December 31, 2023	$ 82	$ 17	$ 8	$ 7	$ 50	$ 28	$ 8	$ 14

	Year Ended December 31, 2022							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2021	$ 72	$ 17	$ 7	$ 9	$ 39	$ 16	$ 8	$ 15
Plus: Current period provision (benefit) for expected credit losses	26	3	6	6	11	9	(1)	3
Less: Write-offs, net of recoveries	16	3	4	5	4	—	—	4
Balance at December 31, 2022	$ 82	$ 17	$ 9	$ 10	$ 46	$ 25	$ 7	$ 14

(a) 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, 2023 and 2022.

	Unbilled customer revenues[(a)]							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2023	$ 991	$ 351	$ 185	$ 208	$ 247	$ 109	$ 64	$ 74
December 31, 2022	912	223	219	247	223	103	74	46

(a) Unbilled customer revenues are classified in Customer accounts receivables, net in the Registrants' Consolidated Balance Sheets.

Other Purchases of Customer and Other Accounts Receivables

The Utility Registrants are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in the utilities' consolidated billing. The following tables present the total receivables purchased.

	Total receivables purchased							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Year ended December 31, 2023	$ 4,056	$ 942	$ 1,099	$ 804	$ 1,211	$ 782	$ 228	$ 201
Year ended December 31, 2022	3,981 [(a)]	965	1,081	792 [(a)]	1,143	723	205	215

(a) Includes $4 million of receivables purchased from Generation prior to the separation on February 1, 2022 for the year ended December 31, 2022.

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

7. Property, Plant, and Equipment (All Registrants)

The following tables present a summary of property, plant, and equipment by asset category at December 31, 2023 and 2022:

Asset Category	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2023								
Electric—transmission and distribution	$ 74,102	$ 34,834	$ 11,295	$ 10,537	$ 19,153	$ 12,429	$ 5,590	$ 5,659
Gas—transportation and distribution	8,818	—	3,905	4,428	748	—	905	—
Common—electric and gas	2,510	—	1,083	1,275	243	—	211	—
Construction work in progress	4,589	1,369	879	561	1,762	1,226	345	189
Other property, plant, and equipment[(a)]	825	107	63	45	120	59	39	28
Total property, plant, and equipment	90,844	36,310	17,225	16,846	22,026	13,714	7,090	5,876
Less: accumulated depreciation	17,251	7,222	4,097	4,744	3,175	4,284	1,925	1,684
Property, plant, and equipment, net	$ 73,593	$ 29,088	$ 13,128	$ 12,102	$ 18,851	$ 9,430	$ 5,165	$ 4,192
December 31, 2022								
Electric—transmission and distribution	$ 69,034	$ 32,906	$ 10,719	$ 9,993	$ 17,165	$ 11,270	$ 5,231	$ 5,219
Gas—transportation and distribution	8,126	—	3,619	4,074	696	—	855	—
Common—electric and gas	2,521	—	1,071	1,317	228	—	206	—
Construction work in progress	4,534	1,174	744	487	2,101	1,526	271	296
Other property, plant and equipment[(a)]	791	106	50	50	114	65	29	26
Total property, plant and equipment	85,006	34,186	16,203	15,921	20,304	12,861	6,592	5,541
Less: accumulated depreciation	15,930	6,673	4,078	4,583	2,618	4,067	1,772	1,551
Property, plant, and equipment, net	$ 69,076	$ 27,513	$ 12,125	$ 11,338	$ 17,686	$ 8,794	$ 4,820	$ 3,990

(a) 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	5-70	5-80	5-75	N/A	5-75	N/A
Common - electric and gas	4-75	N/A	5-55	4-50	5-75	N/A	5-75	N/A
Other property, plant, and equipment	4-61	30-50	50	20-50	10-43	10-33	10-43	13-15

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, 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
December 31, 2022								
Electric—transmission and distribution	2.87%	3.00%	2.29%	2.82%	2.96%	2.58%	3.08%	3.38%
Gas—transportation and distribution	2.14%	N/A	1.87%	2.53%	1.45%	N/A	1.45%	N/A
Common—electric and gas	7.54%	N/A	6.31%	8.20%	8.96%	N/A	10.03%	N/A
December 31, 2021								
Electric—transmission and distribution	2.81%	2.94%	2.28%	2.80%	2.87%	2.56%	2.86%	3.21%
Gas—transportation and distribution	2.13%	N/A	1.84%	2.54%	1.47%	N/A	1.47%	N/A
Common—electric and gas	7.31%	N/A	6.34%	7.88%	8.33%	N/A	8.69%	N/A

AFUDC

The following table summarizes credits to AFUDC by year:

	For the Years Ended December 31,		
	2023	**2022**	**2021**
Exelon	$ 256	$ 215	$ 189
ComEd	72	54	47
PECO	46	42	34
BGE	25	29	36
PHI	113	90	72
Pepco	85	69	59
DPL	16	10	8
ACE	12	11	5

See Note 1 — Significant Accounting Policies for additional information regarding property, plant and equipment policies. See Note 16 — 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)

8. 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, 2023 and 2022 were as follows:

		Transmission NJ/DE[(a)]
Operator		**PSEG/DPL**
Ownership interest		various
Exelon's share at December 31, 2023:		
Plant in service	$	103
Accumulated depreciation		56
Construction work in progress		2
Exelon's share at December 31, 2022:		
Plant in service	$	103
Accumulated depreciation		56
Construction work in progress		—

(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, 2023 and 2022 were as follows:

	PECO		PHI		DPL		ACE	
Ownership interest		56 %		44 %		27 %		17 %
Registrant's share at December 31, 2023:								
Plant in service	$	7	$	6	$	4	$	2
Accumulated depreciation		—		—		—		—
Construction work in progress		70		58		36		22
Registrant's share at December 31, 2022:								
Plant in service	$	7	$	6	$	4	$	2
Accumulated depreciation		—		—		—		—
Construction work in progress		41		36		22		14

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)

9. 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, 2021 to December 31, 2023:

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
AROs at December 31, 2021	$ 274	$ 146	$ 29	$ 26	$ 70	$ 45	$ 16	$ 9
Revisions in estimates of cash flows	(8)	2	(1)	3	(13)	(8)	(3)	(2)
Accretion expense[(a)]	8	4	1	1	2	2	—	—
Payments	(3)	(2)	(1)	—	—	—	—	—
AROs at December 31, 2022	$ 271	$ 150	$ 28	$ 30	$ 59	$ 39	$ 13	$ 7
Revisions in estimates of cash flows	(9)	(3)	(1)	1	(6)	(4)	(1)	(1)
Accretion expense[(a)]	11	6	1	1	3	2	1	—
Payments	(4)	(3)	(1)	—	—	—	—	—
AROs at December 31, 2023	$ 269	$ 150	$ 27	$ 32	$ 56	$ 37	$ 13	$ 6

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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.

10. 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, 2023. Exelon, ComEd, PECO, and BGE did not have material finance leases in 2023, 2022, or 2021.

	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	1-82	1-29	1-10	1-82	1-8	1-8	1-8	1-7
Options to extend the term	3-30	N/A	N/A	3-5	3-30	5	3-30	5
Options to terminate within	9	N/A	N/A	N/A	N/A	N/A	N/A	N/A

(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, 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
For the year ended December 31, 2022								
Operating lease costs	$ 66	$ 2	$ —	$ 15	$ 42	$ 10	$ 12	$ 6
Variable lease costs	8	1	—	—	2	1	1	1
Total lease costs[(a)]	$ 74	$ 3	$ —	$ 15	$ 44	$ 11	$ 13	$ 7
For the year ended December 31, 2021								
Operating lease costs	$ 84	$ 3	$ —	$ 30	$ 43	$ 10	$ 12	$ 6
Variable lease costs	7	1	—	1	1	—	—	—
Total lease costs[(a)]	$ 91	$ 4	$ —	$ 31	$ 44	$ 10	$ 12	$ 6

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(a) Excludes sublease income recorded at Exelon, PHI, and DPL of $4 million for the years ended December 31, 2023, 2022, and 2021.

The components of financing lease costs were as follows:

	PHI	Pepco	DPL	ACE
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
For the year ended December 31, 2022				
Amortization of ROU asset	$ 14	$ 5	$ 6	$ 3
Interest on lease liabilities	4	1	2	1
Total finance lease cost	$ 18	$ 6	$ 8	$ 4
For the year ended December 31, 2021				
Amortization of ROU asset	$ 11	$ 4	$ 4	$ 3
Interest on lease liabilities	2	1	1	—
Total finance lease cost	$ 13	$ 5	$ 5	$ 3

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:

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

	Operating Leases							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
At December 31, 2023								
Operating lease ROU assets								
Other deferred debits and other assets	$ 257	$ —	$ 1	$ 29	$ 152	$ 31	$ 32	$ 8
Operating lease liabilities								
Other current liabilities	$ 38	$ —	$ —	$ 4	$ 30	$ 5	$ 7	$ 3
Other deferred credits and other liabilities	248	—	—	17	141	30	36	6
Total operating lease liabilities	$ 286	$ —	$ —	$ 21	$ 171	$ 35	$ 43	$ 9
At December 31, 2022								
Operating lease ROU assets								
Other deferred debits and other assets	$ 265	$ 2	$ 1	$ 2	$ 180	$ 36	$ 39	$ 9
Operating lease liabilities								
Other current liabilities	$ 40	$ 2	$ —	$ —	$ 31	$ 6	$ 8	$ 3
Other deferred credits and other liabilities	266	—	1	4	167	34	42	7
Total operating lease liabilities	$ 306	$ 2	$ 1	$ 4	$ 198	$ 40	$ 50	$ 10

	Finance Leases			
	PHI	Pepco	DPL	ACE
At December 31, 2023				
Finance lease ROU assets				
Plant, property and equipment, net	$ 72	$ 25	$ 28	$ 18
Finance lease liabilities				
Long-term debt due within one year	$ 15	$ 5	$ 6	$ 4
Long-term debt	59	21	23	15
Total finance lease liabilities	$ 74	$ 26	$ 29	$ 19
At December 31, 2022				
Finance lease ROU assets				
Plant, property and equipment, net	$ 74	$ 25	$ 31	$ 18
Finance lease liabilities				
Long-term debt due within one year	$ 12	$ 4	$ 5	$ 3
Long-term debt	64	21	27	16
Total finance lease liabilities	$ 76	$ 25	$ 32	$ 19

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

Future minimum lease payments for operating and finance leases as of December 31, 2023 were as follows:

	Operating Leases							
Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2024	$ 49	$ —	$ —	$ 4	$ 36	$ 7	$ 9	$ 3
2025	47	—	—	4	34	5	8	3
2026	43	—	—	4	30	5	5	1
2027	41	—	—	2	30	4	6	1
2028	41	—	—	2	30	4	6	1
Remaining years	130	—	—	22	40	16	21	1
Total	351	—	—	38	200	41	55	10
Interest	65	—	—	17	29	6	12	1
Total operating lease liabilities	$ 286	$ —	$ —	$ 21	$ 171	$ 35	$ 43	$ 9

	Finance Leases			
Year	PHI	Pepco	DPL	ACE
2024	$ 16	$ 6	$ 6	$ 4
2025	16	6	6	4
2026	16	6	6	4
2027	14	5	6	3
2028	10	3	4	3
Remaining years	8	2	3	3
Total	80	28	31	21
Interest	6	2	2	2
Total finance lease liabilities	$ 74	$ 26	$ 29	$ 19

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, 2023	8.8	1.8	5.0	17.1	6.1	7.6	7.4	3.2
At December 31, 2022	9.5	1.0	5.5	70.9	6.8	8.1	7.9	3.3

	Finance Leases			
	PHI	Pepco	DPL	ACE
At December 31, 2023	4.9	4.9	4.8	5.1
At December 31, 2022	5.5	5.4	5.5	5.6

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, 2023	4.0 %	0.7 %	2.5 %	5.0 %	4.2 %	4.1 %	4.0 %	3.6 %
At December 31, 2022	3.9 %	2.6 %	2.3 %	4.5 %	4.2 %	4.0 %	4.0 %	3.3 %

	Finance Leases			
	PHI	Pepco	DPL	ACE
At December 31, 2023	2.7 %	2.7 %	2.6 %	2.8 %
At December 31, 2022	2.3 %	2.3 %	2.3 %	2.4 %

(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, 2023	$ 65	$ 2	$ —	$ 15	$ 37	$ 7	$ 9	$ 3
For the year ended December 31, 2022	66	3	—	16	37	8	9	4
For the year ended December 31, 2021	93	3	—	46	39	8	9	4

	Financing Cash Flows from Finance Leases			
	PHI	Pepco	DPL	ACE
For the year ended December 31, 2023	$ 15	$ 5	$ 6	$ 4
For the year ended December 31, 2022	13	5	5	3
For the year ended December 31, 2021	10	3	4	3

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, 2023	$ 35	$ —	$ —	$ 32	$ 3	$ —	$ 1	$ 2
For the year ended December 31, 2022	46	—	—	—	2	—	1	1
For the year ended December 31, 2021	1	—	—	(1)	1	—	1	—

	Finance Leases			
	PHI	Pepco	DPL	ACE
For the year ended December 31, 2023	$ 11	$ 5	$ 3	$ 3
For the year ended December 31, 2022	14	4	7	3
For the year ended December 31, 2021	32	12	12	8

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, 2023. ACE did not have any operating leases for which they are the lessors for the years ended December 31, 2023, 2022, and 2021.

	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
Real estate	●	●	●	●	●	●	●

(in years)	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
Remaining lease terms	1-79	1-13	1-79	19	1-9	1-2	8-9
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, 2023							
Operating lease income	$ 5	$ —	$ —	$ —	$ 4	$ —	$ 3
Variable lease income	1	—	—	—	1	—	1
For the year ended December 31, 2022							
Operating lease income	$ 4	$ —	$ —	$ —	$ 4	$ —	$ 3
Variable lease income	1	—	—	—	1	—	1
For the year ended December 31, 2021							
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, 2023 were as follows:

Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL
2024	$ 6	$ 1	$ 1	$ —	$ 4	$ —	$ 4
2025	6	1	1	—	4	—	4
2026	6	—	1	—	5	—	4
2027	6	—	—	—	5	—	4
2028	5	—	—	—	5	—	4
Remaining years	22	—	3	1	18	—	18
Total	$ 51	$ 2	$ 6	$ 1	$ 41	$ —	$ 38

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

11. Asset Impairments (Exelon and BGE)

In the third quarter of 2022, a review of the impacts of COVID-19 on office use resulted in plans to cease the renovation and dispose of an office building at BGE before the asset was placed into service. BGE determined that the carrying value was not recoverable and that its fair value was less than carrying value. As a result, in 2022, a pre-tax impairment charge of $48 million was recorded in Operating and maintenance expense in Exelon's and BGE's Consolidated Statements of Operations and Comprehensive Income. The fair value used in the analysis was based on an estimate of an expected sales price. The office building met all of the criteria for classification as held for sale as of December 31, 2023, and therefore is reported within Other current assets in Exelon's and BGE's Balance Sheets as of December 31, 2023.

12. 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, 2023 and 2022. There were no additions or impairments during the years ended December 31, 2023 and 2022.

	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 5 — 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 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.

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

2023 and 2022 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, 2023 and 2022. 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 3 — 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, 2023 and 2022. 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, 2023 and 2022. 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, 2023			December 31, 2022		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Exelon						
Unamortized Energy Contracts	$ (1,515)	$ 1,480	$ (35)	$ (1,515)	$ 1,470	$ (45)
Software License	81	(70)	11	81	(61)	20
Exelon Total	$ (1,434)	$ 1,410	$ (24)	$ (1,434)	$ 1,409	$ (25)
PHI						
Unamortized Energy Contracts	$ (1,515)	$ 1,480	$ (35)	$ (1,515)	$ 1,470	$ (45)

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2023, 2022, and 2021:

For the Years Ended December 31,	Exelon[(a)]	PHI[(a)]
2023	$ (1)	$ (10)
2022[(b)]	(182)	(190)
2021	(83)	(92)

(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.
(b) On March 23, 2022, the NJBPU approved a petition by ACE to terminate the provisions in its PPAs. As such, the contract was fully amortized during the year ended December 31, 2022. See Note 3 - Regulatory Matters for additional information.

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

13. 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, 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

	For the Year Ended December 31, 2022							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:								
Federal								
Current	$ (24)	$ 29	$ 13	$ (1)	$ 16	$ 9	$ (2)	$ 6
Deferred	106	117	18	(3)	(23)	(2)	2	(15)
Investment tax credit amortization	(3)	(1)	—	—	(1)	—	—	—
State								
Current	(13)	(6)	(4)	—	2	—	—	—
Deferred	283	125	52	12	15	(16)	14	12
Total	$ 349	$ 264	$ 79	$ 8	$ 9	$ (9)	$ 14	$ 3

	For the Year Ended December 31, 2021							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Included in operations:								
Federal								
Current	$ (152)	$ (30)	$ 1	$ (18)	$ 18	$ 22	$ 2	$ 1
Deferred	89	113	20	34	(52)	(17)	(14)	(26)
Investment tax credit amortization	(2)	(1)	—	—	(1)	—	—	—
State								
Current	(46)	(41)	—	—	—	1	1	—
Deferred	149	131	(9)	(51)	77	9	53	12
Total	$ 38	$ 172	$ 12	$ (35)	$ 42	$ 15	$ 42	$ (13)

Rate Reconciliation

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

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

	For the Year Ended December 31, 2023[a]							
	Exelon	ComEd	PECO[b]	BGE	PHI	Pepco	DPL	ACE
U.S. federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit[c]	3.9	7.9	(1.0)	6.4	5.9	5.5	6.1	7.1
Plant basis differences	(3.9)	(0.5)	(14.4)	(0.9)	(1.4)	(2.2)	(0.7)	(0.4)
Excess deferred tax amortization	(6.6)	(5.5)	(2.4)	(4.6)	(8.6)	(9.6)	(9.4)	(4.2)
Amortization of investment tax credit, including deferred taxes on basis differences	(0.1)	(0.1)	—	—	(0.1)	—	(0.1)	(0.2)
Tax credits	(0.6)	(0.6)	—	(0.6)	(0.6)	(0.7)	(0.4)	(0.5)
Other	0.1	0.2	0.2	0.2	0.2	0.3	—	0.3
Effective income tax rate	13.8 %	22.4 %	3.4 %	21.5 %	16.4 %	14.3 %	16.5 %	23.1 %

	For the Year Ended December 31, 2022[a]							
	Exelon	ComEd	PECO[d]	BGE[d]	PHI[d]	Pepco[d]	DPL[d]	ACE[d]
U.S. federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of Federal income tax benefit[e]	8.8	8.0	5.8	2.6	2.1	(4.1)	6.5	6.9
Plant basis differences	(4.1)	(0.6)	(11.9)	(1.0)	(1.7)	(2.7)	(0.7)	(0.7)
Excess deferred tax amortization	(11.8)	(5.6)	(3.0)	(19.8)	(19.5)	(16.8)	(18.4)	(24.5)
Amortization of investment tax credit, including deferred taxes on basis differences	(0.1)	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Tax credits[f]	0.1	(0.3)	—	(0.7)	(0.7)	(0.7)	(0.6)	(0.5)
Other[g]	0.6	—	0.2	0.1	0.4	0.3	0.1	—
Effective income tax rate	14.5 %	22.4 %	12.1 %	2.1 %	1.5 %	(3.0)%	7.7 %	2.0 %

	For the Year Ended December 31, 2021[a]							
	Exelon	ComEd	PECO[h]	BGE[h]	PHI	Pepco[h]	DPL[h]	ACE[h]
U.S. federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:								
State income taxes, net of federal income tax benefit	5.0	7.8	(1.4)	(10.8)	10.1	2.7	25.0	7.4
Plant basis differences	(5.4)	(0.8)	(13.6)	(1.7)	(1.1)	(1.6)	(0.8)	(0.2)
Excess deferred tax amortization	(17.2)	(7.6)	(3.8)	(16.3)	(22.4)	(16.4)	(20.0)	(37.1)
Amortization of investment tax credit, including deferred taxes on basis differences	(0.1)	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Tax credits	(0.7)	(0.5)	—	(0.9)	(0.5)	(0.5)	(0.4)	(0.5)
Other	(0.3)	(1.0)	0.1	(0.6)	—	(0.4)	0.1	(0.2)
Effective income tax rate	2.3 %	18.8 %	2.3 %	(9.4)%	7.0 %	4.8 %	24.7 %	(9.8)%

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(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions.
(c) For Exelon, the lower state income taxes, net of federal income tax benefit, is primarily due to the long-term marginal state income tax rate change of $54 million.
(d) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions partially offset by higher state income taxes, net of federal income tax benefit, related to a one-time expense of $38 million attributable to the change in the Pennsylvania corporate income tax rate. For BGE, PHI, Pepco, DPL, and ACE, the lower effective tax rate is primarily related to the acceleration of certain income tax benefits due to transmission and distribution rate case settlements.

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

(e) For Exelon, the higher state income taxes, net of federal income tax benefit, is primarily due to the long-term marginal state income tax rate change of $67 million and the recognition of a valuation allowance of $40 million against the net deferred tax asset position for certain standalone state filing jurisdictions, partially offset by a one-time impact associated with a state tax benefit of $43 million and indemnification adjustments pursuant to the Tax Matters Agreement of $11 million as a result of the separation. For PECO, the higher state income taxes, net of federal income tax benefit, related to a one-time expense of $38 million attributable to the change in the Pennsylvania corporate income tax rate.
(f) For Exelon, reflects the income tax expense related to the write-off of federal tax credits subject to recapture of $15 million as a result of the separation.
(g) For Exelon, reflects the nondeductible transaction costs of approximately $12 million arising as part of the separation and indemnification adjustments pursuant to the Tax Matters Agreement of $9 million.
(h) For PECO, the lower effective tax rate is primarily related to plant basis differences attributable to tax repair deductions. For BGE, the income tax benefit is primarily due to the Maryland multi-year plan which resulted in the acceleration of certain income tax benefits. For Pepco, the lower effective tax rate is primarily related to the acceleration of certain income tax benefits due to transmission and distribution rate case settlements. For DPL, the higher effective tax rate is primarily related to a state income tax expense, net of federal income tax benefit, due to the recognition of a valuation allowance of approximately $31 million against a deferred tax asset associated with Delaware net operating loss carryforwards as a result of a change in Delaware tax law. For ACE, the income tax benefit is primarily due to a distribution rate case settlement which allows ACE to retain certain tax benefits.

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, 2023 and 2022 are presented below:

	At December 31, 2023							
	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Plant basis differences	$ (12,631)	$ (4,993)	$ (2,264)	$ (2,064)	$ (3,262)	$ (1,454)	$ (947)	$ (850)
Accrual based contracts	8	—	—	—	8	—	—	—
Derivatives and other financial instruments	46	37	—	—	2	—	—	—
Deferred pension and postretirement obligation	524	(299)	(36)	(26)	(78)	(70)	(35)	(2)
Deferred debt refinancing costs	115	(5)	—	(2)	104	(3)	(2)	(1)
Regulatory assets and liabilities	(1,429)	(405)	(208)	(4)	(52)	9	45	(4)
Tax loss carryforward, net of valuation allowances	295	—	47	77	72	—	18	52
Tax credit carryforward	281	—	—	—	—	—	—	—
Corporate Alternative Minimum Tax	264	118	82	55	—	—	2	11
Investment in partnerships	(28)	—	—	—	—	—	—	—
Other, net	619	227	58	21	186	88	16	25
Deferred income tax liabilities (net)	(11,936)	(5,320)	(2,321)	(1,943)	(3,020)	(1,430)	(903)	(769)
Unamortized investment tax credits	(13)	(7)	—	(2)	(4)	(1)	(1)	(2)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (11,949)	$ (5,327)	$ (2,321)	$ (1,945)	$ (3,024)	$ (1,431)	$ (904)	$ (771)

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

	At December 31, 2022							
	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Plant basis differences	$ (12,130)	$ (4,823)	$ (2,119)	$ (1,949)	$ (3,131)	$ (1,394)	$ (906)	$ (813)
Accrual based contracts	10	—	—	—	10	—	—	—
Derivatives and other financial instruments	26	23	—	—	2	—	—	—
Deferred pension and postretirement obligation	551	(300)	(31)	(31)	(80)	(76)	(39)	(3)
Deferred debt refinancing costs	132	(5)	—	(2)	111	(4)	(2)	(1)
Regulatory assets and liabilities	(1,107)	(131)	(169)	57	(50)	7	43	11
Tax loss carryforward, net of valuation allowances	250	—	33	72	71	3	20	46
Tax credit carryforward	468	—	—	—	—	—	—	—
Investment in partnerships	(21)	—	—	—	—	—	—	—
Other, net	591	223	73	23	182	83	16	28
Deferred income tax liabilities (net)	(11,230)	(5,013)	(2,213)	(1,830)	(2,885)	(1,381)	(868)	(732)
Unamortized investment tax credits	(14)	(8)	—	(2)	(4)	(1)	(1)	(2)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$ (11,244)	$ (5,021)	$ (2,213)	$ (1,832)	$ (2,889)	$ (1,382)	$ (869)	$ (734)

The following table provides Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's, and ACE's carryforwards, of which the state related items are presented on a post-apportioned basis, as well as, any corresponding valuation allowances at December 31, 2023.

	Exelon	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Federal								
Federal net operating loss carryforward[(a)]	$ 130	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Deferred taxes on Federal net operating loss	27	—	—	—	—	—	—	—
Federal general business credits carryforwards[(b)]	281	—	—	—	—	—	—	—
Corporate Alternative Minimum Tax credit carryforward[(c)]	264	118	82	55	—	—	2	11
State								
State net operating loss carryforwards	5,629	—	1,286	1,187	1,509	—	743	736
Deferred taxes on state tax attributes (net of federal taxes)	341	—	51	77	104	—	50	52
Valuation allowance on state tax attributes (net of federal taxes)[(d)]	73	—	4	—	32	—	32	—
Year in which net operating loss or credit carryforwards will begin to expire[(e)]	2035	N/A	2032	2033	2029	N/A	2035	2031

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(a) For Exelon, the federal net operating loss carryforward has an indefinite carryforward period.
(b) For Exelon, the federal general business credit carryforward will begin expiring in 2035.
(c) For Exelon, ComEd, PECO, BGE, DPL and ACE, the Corporate Alternative Minimum Tax credit carryforward has an indefinite carryforward period.

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

(d) 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 certain 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 restricts the ability for corporate taxpayers to monetize net operating losses.
(e) 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, and ACE. ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

	Exelon[(a)]	PHI	ACE
Balance at January 1, 2021	$ 125	$ 52	$ 15
Change to positions that only affect timing	13	3	1
Increases based on tax positions related to 2021	4	1	—
Increases based on tax positions prior to 2021	4	—	—
Decreases based on tax positions prior to 2021	(3)	—	—
Balance at December 31, 2021	$ 143	$ 56	$ 16
Change to positions that only affect timing	(1)	1	1
Increases based on tax positions related to 2022	3	2	—
Increases based on tax positions prior to 2022	3	—	—
Decreases based on tax positions prior to 2022	—	—	—
Balance at December 31, 2022	$ 148	$ 59	$ 17
Change to positions that only affect timing	(57)	(9)	(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	$ 15

(a) At December 31, 2023 and 2022, Exelon recorded a receivable of $31 million and $50 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.

Recognition of 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, 2023	$ 71
December 31, 2022	90
December 31, 2021	77

Unrecognized tax benefits for which significant increases or decreases are possible within 12 months after the reporting date

At December 31, 2023, ACE has approximately $14 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date based on the outcome of pending court cases involving other taxpayers. The unrecognized tax benefit, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

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

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, 2023 [(a)]	$ 62
December 31, 2022 [(b)]	45

(a) At December 31, 2023, Exelon classified $21 million and $41 million of the interest receivable as current and noncurrent, respectively, based on the expected timing for settlement in cash. At December 31, 2023, Exelon recorded a receivable of $5 million in noncurrent Other assets in the Consolidated Balance Sheet for Constellation's share of net interest for periods prior to the separation.
(b) At December 31, 2022, the interest receivable balance is not expected to be settled in cash within the next twelve months and is therefore classified as a noncurrent receivable. At December 31, 2022, Exelon recorded a receivable of $1 million in noncurrent Other assets in the Consolidated Balance Sheet for Constellation's share of net interest for periods prior to the separation.

The Registrants did not record material interest and penalty expense related to tax positions reflected in their Consolidated Balance Sheets. Interest expense and penalty expense are recorded in Interest expense, net and Other, net, respectively, in Other income and deductions in the 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)]	2010-2022	All Registrants
Delaware separate corporate income tax returns	Same as federal	DPL
District of Columbia combined corporate income tax returns	2020-2022	Exelon, PHI, Pepco
Illinois unitary corporate income tax returns	2012-2022	Exelon, ComEd
Maryland separate company corporate net income tax returns	Same as federal	BGE, Pepco, DPL
New Jersey separate corporate income tax returns	2017-2018	Exelon
New Jersey combined corporate income tax returns	2019-2022	Exelon
New Jersey separate corporate income tax returns	2019-2022	ACE
New York combined corporate income tax returns	2015-2022	Exelon
Pennsylvania separate corporate income tax returns	2020-2022	Exelon
Pennsylvania separate corporate income tax returns	2020-2022	PECO

(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.

Other Tax Matters

Separation (Exelon)

In the first quarter of 2022, in connection with the separation, Exelon recorded an income tax expense related to continuing operations of $148 million primarily due to the long-term marginal state income tax rate change of $54 million discussed further below, the recognition of valuation allowances of approximately $40 million against the net deferred tax assets positions for certain standalone state filing jurisdictions, the write-off of federal and state tax credits subject to recapture of $17 million, and nondeductible transaction costs for federal and state taxes of $24 million.

Tax Matters Agreement (Exelon)

In connection with the separation, Exelon entered into a TMA with Constellation. 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.

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

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. In 2023, Exelon remitted $9 million of payments to Constellation. At December 31, 2023, Exelon recorded a payable of $11 million in Other current liabilities that is due to 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.

Tax Attributes. At the date of separation certain tax attributes, primarily pre-closing tax credit carryforwards, that were generated by Constellation 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 2023, Exelon remitted $21 million of payments to Constellation for the utilization of pre-closing tax credit carryforwards. At December 31, 2023, Exelon recorded a payable of $182 million and $331 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 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.

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. Exelon is continuing to assess the financial statement impacts of the IRA and will update estimates based on future guidance issued by the U.S. Treasury.

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 years ended December 31, 2023, 2022, and 2021.

December 31, 2023	**Exelon**
Decrease to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	$ (54)
December 31, 2022	
Increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	67
December 31, 2021	
Increase to Deferred Income Tax Liability and Income Tax Expense, Net of Federal Taxes	27

Pennsylvania Corporate Income Tax Rate Change (Exelon and PECO)

On July 8, 2022, Pennsylvania enacted House Bill 1342, which will permanently reduce the corporate income tax rate from 9.99% to 4.99%. The tax rate will be reduced to 8.99% for the 2023 tax year. Starting with the 2024 tax year, the rate is reduced by 0.50% annually until it reaches 4.99% in 2031. As a result of the rate change, in the third quarter of 2022, Exelon and PECO recorded a one-time decrease to deferred income taxes of $390 million with a corresponding decrease to the deferred income taxes regulatory asset of $428 million for the amounts that are expected to be settled through future customer rates and an increase to income tax expense of $38 million (net of federal taxes). The tax rate decrease is not expected to have a material ongoing impact to Exelon's and PECO's financial statements. There were no changes to PECO's marginal state income tax rates for the years ended December 31, 2022, and 2021.

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

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, 2023, 2022, and 2021.

	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2023[(a)]	$ 13	$ 19	$ —	$ 10	$ 4	$ —	$ 2
December 31, 2022[(b)]	1	47	—	28	23	3	2
December 31, 2021[(c)]	1	19	—	17	16	—	—

(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.
(b) BGE 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.
(c) BGE, DPL, and ACE 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.

14. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension and OPEB plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018 for most newly-hired BSC non-represented, non-craft, employees, January 1, 2021 for most newly-hired utility management employees, and for certain newly-hired union employees pursuant to their collective bargaining agreements, these newly-hired employees are not eligible for pension benefits, and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented, non-craft, employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits. Effective January 1, 2021, most non-represented, non-craft, employees who are under the age of 40 are not eligible for retiree health care benefits. Effective January 1, 2022, management employees retiring on or after that date are no longer eligible for retiree life insurance benefits.

Effective February 1, 2022, in connection with the separation, pension and OPEB obligations and assets for current and former employees of the Constellation business and certain other former employees of Exelon and its subsidiaries transferred to pension and OPEB plans and trusts maintained by Constellation or its subsidiaries. The Exelon New England Union Employees Pension Plan and Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B were transferred. The following OPEB plans were also transferred: Constellation Mystic Power, LLC Post-Employment Medical Savings Account Plan; Exelon New England Union Post-Employment Medical Savings Account Plan; and the Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees.

As a result of the separation, Exelon restructured certain of its qualified pension plans. Pension obligations and assets for current and former employees continuing with Exelon and who were participants in the Exelon Employee Pension Plan for Clinton, TMI, and Oyster Creek, Pension Plan of Constellation Energy Nuclear Group, LLC, and Nine Mile Point Pension Plan were merged into the Pension Plan of Constellation Energy

Group, Inc, which was subsequently renamed, Exelon Pension Plan (EPP). Exelon employees who participated in these plans prior to the separation now participate in the EPP. The merging of the plans did not change the benefits offered to the plan participants and, thus, had no impact on Exelon's pension obligations.

The tables below show the pension and OPEB plans in which current and former employees of each operating company participated as of December 31, 2023:

	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 (SPBP)	X	X		X			
Exelon Corporation Supplemental Management Retirement Plan (SMRP)	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
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	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	
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

As of February 1, 2022, in connection with the separation, Exelon's pension and OPEB plans were remeasured. The remeasurement and separation resulted in a decrease to the Pension obligation, net of plan assets, of $921 million and a decrease to the OPEB obligation of $893 million. Additionally, AOCI decreased by $1,994 million (after-tax) and Regulatory assets and liabilities increased by $14 million and $5 million, respectively. Key assumptions were held consistent with the year end December 31, 2021 assumptions with the exception of the discount rate.

During the first quarter of 2023, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2023. This valuation resulted in an increase to the pension obligation of $27 million and an increase to the OPEB obligations of $2 million. Additionally, AOCI increased by $ 10 million (after-tax) and Regulatory assets and liabilities increased by $18 million and $1 million, respectively.

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	
	2023	2022	2023	2022
Change in benefit obligation:				
Net benefit obligation as of the beginning of year	$ 10,677	$ 14,236	$ 1,884	$ 2,502
Service cost	155	236	26	41
Interest cost	578	439	101	76
Plan participants' contributions	—	—	27	26
Actuarial loss (gain)[(a)]	406	(3,379)	55	(604)
Plan amendments	4	—	—	—
Settlements	(42)	—	—	—
Gross benefits paid	(790)	(855)	(185)	(157)
Net benefit obligation as of the end of year	$ 10,988	$ 10,677	$ 1,908	$ 1,884

	Pension Benefits		OPEB	
	2023	2022	2023	2022
Change in plan assets:				
Fair value of net plan assets as of the beginning of year	$ 9,521	$ 12,165	$ 1,351	$ 1,665
Actual return on plan assets	638	(2,359)	108	(225)
Employer contributions	75	570	54	42
Plan participants' contributions	—	—	27	26
Gross benefits paid	(790)	(855)	(185)	(157)
Settlements	(42)	—	—	—
Fair value of net plan assets as of the end of year	$ 9,402	$ 9,521	$ 1,355	$ 1,351

(a) The pension and OPEB losses in 2023 primarily reflect a decrease in the discount rate. The pension and OPEB gains in 2022 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	
	2023	2022	2023	2022
Other current liabilities	$ 15	$ 47	$ 26	$ 26
Pension obligations	1,571	1,109	—	—
Non-pension postretirement benefit obligations	—	—	527	507
Unfunded status (net benefit obligation less plan assets)	$ 1,586	$ 1,156	$ 553	$ 533

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 obligation (APBO), respectively, in excess of plan assets has been disclosed in the Obligations and Plan Assets table above as all pension and OPEB plans are underfunded.

	Exelon	
	2023	2022
ABO	$ 10,376	$ 10,108
Fair value of net plan assets	9,279	9,427

Components of Net Periodic Benefit Costs

The majority of the 2023 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 5.53%. The majority of the 2023 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 5.51%.

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, 2023, 2022, and 2021.

	Pension Benefits			OPEB		
	2023	2022	2021	2023	2022	2021
Components of net periodic benefit cost:						
Service cost	$ 155	$ 236	$ 294	$ 26	$ 41	$ 51
Interest cost	578	439	406	101	76	69
Expected return on assets	(755)	(822)	(843)	(83)	(99)	(99)
Amortization of:						
Prior service cost (credit)	2	2	2	(10)	(19)	(25)
Actuarial loss (gain)	166	295	399	(2)	12	27
Settlement and other charges	20	—	7	—	—	1
Net periodic benefit cost	$ 166	$ 150	$ 265	$ 32	$ 11	$ 24

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

Cost Allocation to Exelon Subsidiaries

All 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 (benefit). 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 the Utility Registrants, 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
2023	$ 198	$ 26	$ (14)	$ 56	$ 99	$ 34	$ 18	$ 13
2022	161	60	(9)	44	53	9	3	12
2021	288	129	8	64	49	6	2	11

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) is 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, 2023, 2022, and 2021 for all plans combined. The tables include amounts related to Generation prior to the separation.

	Pension Benefits			OPEB		
	2023	2022	2021	2023	2022	2021
Changes in plan assets and benefit obligations recognized in AOCI and Regulatory assets (liabilities):						
Current year actuarial loss (gain)	$ 523	$ (226)	$ (700)	$ 30	$ (271)	$ (270)
Amortization of actuarial (loss) gain	(166)	(295)	(598)	2	(12)	(37)
Separation of Constellation	—	(2,631)	—	—	(43)	—
Current year prior service cost	4	—	—	—	—	—
Amortization of prior service (cost) credit	(2)	(2)	(3)	10	19	34
Settlements	(20)	—	(27)	—	—	(1)
Total recognized in AOCI and Regulatory assets (liabilities)	$ 339	$ (3,154)	$ (1,328)	$ 42	$ (307)	$ (274)
Total recognized in AOCI	$ 99	$ (2,719)	$ (747)	$ 4	$ (74)	$ (130)
Total recognized in Regulatory assets (liabilities)	$ 240	$ (435)	$ (581)	$ 38	$ (233)	$ (144)

(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, 2023 and 2022, respectively, for all plans combined:

	Pension Benefits		OPEB	
	2023	2022	2023	2022
Prior service cost (credit)	$ 21	$ 19	$ (45)	$ (55)
Actuarial loss (gain)	3,948	3,611	(101)	(133)
Total	$ 3,969	$ 3,630	$ (146)	$ (188)
Total included in AOCI	$ 972	$ 873	$ (17)	$ (21)
Total included in Regulatory assets (liabilities)	$ 2,997	$ 2,757	$ (129)	$ (167)

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:

	2023	2022	2021
Pension plans	12.6	12.5	12.4
OPEB plans:			
Benefit Eligibility Age	8.1	7.9	7.6
Expected Retirement	9.3	9.1	8.8

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, 2023 and 2022, 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, 2023 and 2022. 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	
	2023	2022	2023	2022
Discount rate[(a)]	5.19 %	5.53 %	5.17 %	5.51 %
Investment crediting rate[(b)]	5.03 %	5.07 %	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 and ultimate trend rate of 5.00%	Initial and ultimate trend rate of 5.00%

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(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 5.11% - 5.27% and 5.15% - 5.17% for pension and OPEB plans, respectively, as of December 31, 2023 and 5.46% - 5.60% and 5.49% - 5.51% for pension and OPEB plans, respectively, as of December 31, 2022.
(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, 2023, 2022 and 2021:

	Pension Benefits			OPEB		
	2023	2022	2021	2023	2022	2021
Discount rate[(a)]	5.53 %	3.24 %	2.58 %	5.51 %	3.20 %	2.51 %
Investment crediting rate[(b)]	5.07 %	3.75 %	3.72 %	N/A	N/A	N/A
Expected return on plan assets[(c)]	7.00 %	7.00 %	7.00 %	6.50 %	6.44 %	6.46 %
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 - 2020 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 - 2020 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%

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(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 5.46%-5.60% and 5.49%-5.51% for pension and OPEB plans, respectively, for the year ended December 31, 2023; 2.55%-3.24% and 2.84%-3.20% for pension and OPEB plans; respectively, for the year ended December 31, 2022; and 2.11%-2.73% and 2.45%-2.63% for pension and OPEB plans, respectively, for the year ended December 31, 2021.
(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). For Exelon, in connection with the separation, additional qualified pension contributions of $207 million and $33 million were completed on February 1, 2022 and March 2, 2022, respectively. The following table provides contributions to the pension and OPEB plans:

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

	Pension Benefits			OPEB		
	2023	2022	2021	2023	2022	2021
Exelon	$ 75	$ 570	$ 343	$ 54	$ 42	$ 63
ComEd	24	176	174	17	8	22
PECO	1	15	17	—	3	1
BGE	—	48	57	19	20	24
PHI	8	69	39	16	9	9
Pepco	1	3	2	11	8	9
DPL	2	1	1	2	—	—
ACE	—	7	3	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 $93 million in 2024. 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 2024:

	Qualified Pension Plans	Non-Qualified Pension Plans	OPEB
Exelon	$ 93	$ 15	$ 47
ComEd	3	1	18
PECO	2	1	1
BGE	17	1	14
PHI	66	8	11
Pepco	—	1	10
DPL	—	—	—
ACE	7	—	—

(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, 2023 were:

	Pension Benefits	OPEB
2024	$ 782	$ 152
2025	783	151
2026	795	152
2027	800	151
2028	792	151
2029 through 2033	3,977	730
Total estimated future benefits payments through 2033	$ 7,929	$ 1,487

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, 2023 were 7.73% and 9.20%, 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 2024 pension and OPEB costs, respectively.

Exelon's pension and OPEB plan target asset allocations as of December 31, 2023 and 2022 were as follows:

	December 31, 2023		December 31, 2022	
Asset Category	Pension Benefits	OPEB	Pension Benefits	OPEB
Equity securities	28 %	44 %	28 %	44 %
Fixed income securities	44 %	41 %	44 %	41 %
Alternative investments[(a)]	28 %	15 %	28 %	15 %
Total	100 %	100 %	100 %	100 %

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(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, 2023. 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, 2023, 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, 2023 and 2022:

	December 31, 2023					December 31, 2022				
	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	$ 267	$ —	$ —	$ —	$ 267	$ 200	$ —	$ —	$ —	$ 200
Equities[b]	1,513	—	1	694	2,208	1,448	—	—	782	2,230
Fixed income:										
U.S. Treasury and agencies	1,291	184	—	—	1,475	986	178	—	—	1,164
State and municipal debt	—	42	—	—	42	—	44	—	—	44
Corporate debt	—	1,792	9	—	1,801	—	1,975	12	—	1,987
Other[b]	—	79	—	788	867	—	63	—	744	807
Fixed income subtotal	1,291	2,097	9	788	4,185	986	2,260	12	744	4,002
Private equity	—	—	—	1,166	1,166	—	—	—	1,169	1,169
Hedge funds	—	—	—	578	578	—	—	—	760	760
Real estate	—	—	—	760	760	—	—	—	821	821
Private credit	—	—	—	626	626	—	—	—	658	658
Pension plan assets subtotal	$ 3,071	$ 2,097	$ 10	$ 4,612	$ 9,790	$ 2,634	$ 2,260	$ 12	$ 4,934	$ 9,840
OPEB plan assets[a]										
Cash and cash equivalents	$ 45	$ —	$ —	$ —	$ 45	$ 39	$ —	$ —	$ —	$ 39
Equities	315	1	—	270	586	305	1	—	273	579
Fixed income:										
U.S. Treasury and agencies	15	54	—	—	69	17	45	—	—	62
State and municipal debt	—	7	—	—	7	—	8	—	—	8
Corporate debt	—	44	—	—	44	—	44	—	—	44
Other	175	4	—	206	385	161	5	—	187	353
Fixed income subtotal	190	109	—	206	505	178	102	—	187	467
Hedge funds	—	—	—	109	109	—	—	—	120	120
Real estate	—	—	—	88	88	—	—	—	106	106
Private credit	—	—	—	22	22	—	—	—	39	39
OPEB plan assets subtotal	$ 550	$ 110	$ —	$ 695	$ 1,355	$ 522	$ 103	$ —	$ 725	$ 1,350
Total pension and OPEB plan assets[c]	$ 3,621	$ 2,207	$ 10	$ 5,307	$ 11,145	$ 3,156	$ 2,363	$ 12	$ 5,659	$ 11,190

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

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(a) See Note 17—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Includes derivative instruments of $51 million and $11 million for the years ended December 31, 2023 and 2022, respectively, which have total notional amounts of $3,351 million and $3,434 million as of December 31, 2023 and 2022, 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 $388 million and $318 million as of December 31, 2023 and 2022, respectively, which include certain derivative assets that have notional amounts of $59 million and $69 million as of December 31, 2023 and 2022, 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 3 - 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, 2023 and 2022:

	Fixed Income	Equities	Private Credit	Total
Pension Assets				
Balance as of January 1, 2023	$ 12	$ —	$ —	$ 12
Actual return on plan assets:				
Relating to assets still held as of the reporting date	—	—	—	—
Relating to assets sold during the period	—	—	—	—
Purchases, sales and settlements:				
Purchases	—	—	—	—
Settlements[(a)]	—	—	—	—
Level 3 transfers (out) in	(3)	1	—	(2)
Balance as of December 31, 2023	$ 9	$ 1	$ —	$ 10

	Fixed Income	Equities	Private Credit	Total
Pension Assets				
Balance as of January 1, 2022	$ 337	$ 2	$ 130	$ 469
Actual return on plan assets:				
Relating to assets still held as of the reporting date	(9)	—	(15)	(24)
Relating to assets sold during the period	(19)	—	13	(6)
Purchases, sales and settlements:				
Purchases	—	—	7	7
Settlements[(a)]	(1)	—	(52)	(53)
Level 3 transfers out[(b)]	(296)	(2)	(83)	(381)
Balance as of December 31, 2022	$ 12	$ —	$ —	$ 12

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(a) Represents cash settlements only.
(b) In 2022, transfers relate to changes in investment structure for certain investments due to the separation.

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 17 - 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, derivatives, private credit, private equity, and real estate investments.

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. For fixed income securities, which consist primarily of corporate debt securities, U.S. government securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds, and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class, or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine 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 primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold fund investments in accordance with a stated set of fund objectives. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds 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. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Managed private credit fund investments are not classified within the fair value hierarchy because their fair value is determined using NAV or its equivalent as a practical expedient.

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

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. These valuation inputs are unobservable. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Real estate. These investments are funds with a direct investment in pools of real estate properties. These funds are reported by the fund manager and are generally based on independent appraisals of the underlying investments from sources with professional qualifications, typically using a combination of market based comparable data and discounted cash flows. These valuation inputs are unobservable. Certain real estate investments cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on 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.

Pension and OPEB assets also include investments in hedge funds. Hedge fund investments include those that employ a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. 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, 2023, 2022, and 2021:

For the Years Ended December 31,	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2023	$ 109	$ 47	$ 15	$ 12	16	$ 4	$ 3	$ 2
2022	91	39	13	11	14	4	3	2
2021	90	35	12	12	14	4	3	2

15. 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. At Exelon, derivative economic hedges related to interest rates are recorded at fair value and offsets are recorded to Electric operating revenues or Interest expense based on the activity the transaction is economically hedging. 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.

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

ComEd's use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade. Cash collateral held by PECO, BGE, Pepco, DPL, and ACE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meets certain qualifications.

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.

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 contracts for between 10-20% of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period.
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.

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(a) See Note 3—Regulatory Matters for additional information.
(b) The fair value of the DPL economic hedge is not material as of December 31, 2023 and 2022.

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 and Other 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. In addition, Exelon Corporate utilized interest rate swaps to manage interest rate exposure and manage potential fluctuations in Electric operating revenues at the corporate level in consolidation, which were directly correlated to yields on U.S. Treasury bonds under ComEd's distribution formula rate through December 31, 2023. These interest rate swaps were accounted for as economic hedges. A hypothetical 50 basis point change in the interest rates associated with Exelon's interest rate swaps as of December 31, 2023 would result in an immaterial impact to Exelon's Consolidated Net Income.

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

Below is a summary of the interest rate hedge balances at December 31, 2023 and 2022.

	December 31, 2023		
	Derivatives Designated as Hedging Instruments	Economic Hedges	Total
Other current assets	$ 11	$ 1	$ 12
Other deferred debits (noncurrent assets)	—	—	—
Total derivative assets	11	1	12
Mark-to-market derivative liabilities (current liabilities)	(24)	(22)	(46)
Total mark-to-market derivative liabilities	(24)	(22)	(46)
Total mark-to-market derivative net liabilities	$ (13)	$ (21)	$ (34)

	December 31, 2022		
	Derivatives Designated as Hedging Instruments	Economic Hedges	Total
Other deferred debits (noncurrent assets)	$ 6	$ 5	$ 11
Total derivative assets	6	5	11
Mark-to-market derivative liabilities (current liabilities)	—	(3)	(3)
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	—	(4)
Total mark-to-market derivative liabilities	(4)	(3)	(7)
Total mark-to-market derivative net assets	$ 2	$ 2	$ 4

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. In January 2023, Exelon Corporate entered into $115 million notional of 5-year maturity floating-to-fixed swaps and $115 million notional of 10-year maturity floating-to-fixed swaps, for a total of $230 million designated as cash flow hedges. In February 2023, Exelon terminated the previously issued floating-to-fixed swaps with a total notional of $1.5 billion upon issuance of $2.5 billion of debt. See Note 16 – Debt and Credit Agreements for additional information on the debt issuance. Prior to the termination, the AOCI derivative gain was $7 million (net of tax). The settlements resulted in a cash receipt of $10 million, which 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.

Since the termination in February 2023, Exelon has entered into additional floating-to-fixed swaps.

The following table provides the notional amounts outstanding held by Exelon at December 31, 2023 and 2022.

	December 31, 2023	December 31, 2022
5-year maturity floating-to-fixed swaps	$ 655	$ 635
10-year maturity floating-to-fixed swaps	655	635
Total	$ 1,310	$ 1,270

The AOCI derivative loss (net of tax) was $10 million as of December 31, 2023 and gain was $2 million as of December 31, 2022. See Note 21 – Changes in Accumulated Other Comprehensive Income (Loss) for additional information.

Economic Hedges (Interest Rate and Other Risk)

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

Exelon Corporate executes derivative instruments to mitigate exposure to fluctuations in interest rates but for which the fair value or cash flow hedge elections were not made. For derivatives intended to serve as economic hedges, fair value is recorded on the balance sheet and changes in fair value each period are recognized in earnings or as a regulatory asset or liability, if regulatory requirements are met, each period.

Exelon Corporate enters into floating-to-fixed interest rate cap swaps to manage a portion of interest rate exposure in connection with existing borrowings. In 2022, Exelon Corporate entered into $1 billion notional of 18-month maturity floating-to-fixed interest rate cap swaps and $850 million notional of 6-month maturity floating-to-fixed interest rate cap swaps, for a total of $1,850 million notional of floating-to-fixed interest rate cap swaps as of December 31, 2022. The 6-month maturity floating-to-fixed interest rate cap swaps of $850 million notional matured in March 2023. Exelon receives payments on the interest rate cap when the floating rate exceeds the fixed rate. Settlements received are immaterial as of December 31, 2023.

Additionally, to manage potential fluctuations in Electric operating revenues related to ComEd's distribution formula rate, Exelon Corporate entered into a total of $4,875 million notional of 30-year constant maturity treasury interest rate (Corporate 30-year treasury) swaps from 2022 through 2023. The Corporate 30-year treasury swaps matured on December 31, 2023 and Exelon recorded a Mark-to-market liability of $22 million for the final settlement amount, which was paid in January 2024.

The following table provides the notional amounts outstanding held by Exelon at December 31, 2023 and 2022.

Hedging Instrument	December 31, 2023	December 31, 2022
Interest rate cap swaps	$ 1,000	$ 1,850
Constant maturity treasury interest rate swaps	—	500
Total	$ 1,000	$ 2,350

For the year ended December 31, 2023, Exelon Corporate recognized the following net pre-tax mark-to-market losses which are also recognized in Net fair value changes related to derivatives in Exelon's Consolidated Statements of Cash Flows.

Income Statement Location	December 31, 2023 (Loss)	December 31, 2022 (Loss)
Electric operating revenues	$ (20)	$ (2)
Interest expense	—	(3)
Total	$ (20)	$ (5)

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 decreased as of December 31, 2023 due to decreasing energy prices. 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, 2023 and 2022

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

	December 31, 2023	December 31, 2022
Exelon	$ 148	$ 297
ComEd	146	77
PECO[(a)]	—	—
BGE	1	23
PHI	1	197
Pepco	1	26
DPL	—	121
ACE	—	50

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(a) PECO had less than one million in cash collateral held with external parties as of December 31, 2023 and 2022.

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, 2023, 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, 2023, they could have been required to post collateral to their counterparties of $25 million, $61 million, and $10 million, respectively.

16. 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

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

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2023 and 2022:

	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	2023[(a)]	2022[(a)]	2023	2022	2023	2022
Exelon[(b)]	$ 4,000	$ 4,000	$ 1,624	$ 1,938	5.58 %	4.77 %
ComEd	$ 1,000	$ 1,000	$ 202	$ 427	5.53 %	4.71 %
PECO	$ 600	$ 600	$ 165	$ 239	5.57 %	4.71 %
BGE	$ 600	$ 600	$ 336	$ 409	5.59 %	4.81 %
PHI[(c)]	$ 900	$ 900	$ 394	$ 414	5.60 %	4.78 %
Pepco	$ 300 [(d)]	$ 300	$ 132	$ 299	5.59 %	4.79 %
DPL	$ 300 [(d)]	$ 300	$ 63	$ 115	5.60 %	4.76 %
ACE	$ 300 [(d)]	$ 300	$ 199	$ —	5.60 %	— %

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(a) Excludes credit facility agreements arranged at minority and 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, 2023 and December 31, 2022. Exelon Corporate had $527 million in outstanding commercial paper as of December 31, 2023 and $449 million outstanding commercial paper as of December 31, 2022.
(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. In January 2024, this ability was utilized to increase ACE's program size to $350 million. As a result, the program size for Pepco did not change and DPL was decreased to $250 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, 2023, the Registrants had the following aggregate bank commitments, credit facility borrowings, and available capacity under their respective credit facilities:

					Available Capacity at December 31, 2023	
Borrower[a]	Facility Type	Aggregate Bank Commitment[b]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper[c]
Exelon[c]	Syndicated Revolver	$ 4,000	$ —	$ 19	$ 3,981	$ 2,357
ComEd	Syndicated Revolver	1,000	—	10	990	788
PECO	Syndicated Revolver	600	—	—	600	435
BGE	Syndicated Revolver	600	—	6	594	258
PHI[d]	Syndicated Revolver	900	—	—	900	506
Pepco	Syndicated Revolver	300	—	—	300	168
DPL	Syndicated Revolver	300	—	—	300	237
ACE	Syndicated Revolver	300	—	—	300	101

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(a) On February 1, 2022, Exelon Corporate and the Utility Registrants' respective syndicated revolving credit facilities were replaced with a new 5-year revolving credit facility.
(b) Excludes credit facility agreements arranged at minority and community banks. See below for additional information.
(c) Includes $900 million aggregate bank commitment related to Exelon Corporate. Exelon Corporate had $3 million outstanding letters of credit as of December 31, 2023. Exelon Corporate had $370 million in available capacity to support additional commercial paper as of December 31, 2023.
(d) Represents the consolidated amounts of Pepco, DPL, and ACE.

The following table reflects the Registrants' credit facility agreements arranged at minority and community banks at December 31, 2023 and 2022. These are excluded from the Maximum Program Size and Aggregate Bank Commitment amounts within the two tables above and the facilities are solely used to issue letters of credit.

	Aggregate Bank Commitments		Outstanding Letters of Credit	
Borrower	2023[a]	2022	2023	2022
Exelon[b]	$ 140	$ 140	$ 10	$ 10
ComEd	40	40	7	7
PECO	40	40	1	1
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 6, 2023 and expire on October 4, 2024.
(b) Represents the consolidated amounts of ComEd, PECO, BGE, Pepco, DPL, and ACE.
(c) Represents the consolidated amounts of Pepco, DPL, and ACE.

Revolving Credit Agreements

On February 1, 2022, Exelon Corporate and the Utility Registrants each entered into a new 5-year revolving credit facility that replaced its existing syndicated revolving credit facility. The following table reflects the credit agreements:

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

Borrower	Aggregate Bank Commitment	Interest Rate
Exelon Corporate	$ 900	SOFR plus 1.275 %
ComEd	$ 1,000	SOFR plus 1.000 %
PECO	$ 600	SOFR plus 0.900 %
BGE	$ 600	SOFR plus 0.900 %
Pepco	$ 300	SOFR plus 1.075 %
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 are presented in the following table:

	Exelon[(a)]	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	0 - 27.5	—	—	—	7.5	—	—
SOFR-based borrowings	90.0 - 127.5	100.0	90.0	90.0	107.5	100.0	100.0

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(a) Includes interest rate adders at Exelon Corporate of 27.5 basis points and 127.5 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, 2023.

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 2023 and was bifurcated into two tranches of $300 million on March 14, 2023 and $200 million on March 24, 2023. The agreements will expire on March 14, 2024 and March 22, 2024, respectively. Pursuant to the loan agreements, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.90% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On October 4, 2022, ComEd entered into a 364-day term loan agreement for $150 million with a variable rate equal to SOFR plus 0.75% and an expiration date of October 3, 2023. The proceeds from this loan were used to repay outstanding commercial paper obligations. The loan agreement is reflected in Exelon's and ComEd's Consolidated Balance Sheets within Short-term borrowings. The balance of the loan was repaid on January 13, 2023 in conjunction with the $400 million and $575 million First Mortgage Bond agreements that were entered into on January 3, 2023.

On May 9, 2023, ComEd entered into a 364-day term loan agreement for $400 million with a variable rate equal to SOFR plus 1.00% and an expiration date of May 7, 2024. The proceeds from this loan were used to repay outstanding commercial paper obligations and for general corporate purposes. The loan agreement is reflected in Exelon's and ComEd's Consolidated Balance Sheets within Short-term borrowings.

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. At both December 31, 2023 and December 31, 2022, $79 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, 2023 and 2022:

Exelon

	Rates			Maturity Date	December 31, 2023	December 31, 2022
Long-term debt						
First mortgage bonds[(a)]	1.05 %	-	7.90 %	2024 - 2053	$ 24,776	$ 22,651
Senior unsecured notes	2.75 %	-	7.60 %	2025 - 2053	10,824	8,324
Unsecured notes	2.25 %	-	6.35 %	2026 - 2053	4,650	4,250
Notes payable and other	1.64 %	-	7.49 %	2025 - 2053	84	86
Long-term software licensing agreement	2.30 %	-	3.95 %	2024 - 2025	12	25
Unsecured tax-exempt bonds	4.15 %	-	4.20 %	2024	33	33
Medium-terms notes (unsecured)			7.72 %	2027	10	10
Loan agreement[(b)]			6.23 %	2024	500	1,400
Total long-term debt					40,889	36,779
Unamortized debt discount and premium, net					(80)	(74)
Unamortized debt issuance costs					(296)	(257)
Fair value adjustment					582	626
Long-term debt due within one year					(1,403)	(1,802)
Long-term debt					$ 39,692	$ 35,272
Long-term debt to financing trusts[(c)]						
Subordinated debentures to ComEd Financing III			6.35 %	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38 %	-	10.50 %	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) Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.85%.
(c) 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, 2023	December 31, 2022
Long-term debt					
First mortgage bonds[(a)]	2.20 % -	6.45 %	2024 - 2053	$ 11,603	$ 10,629
Other		7.49 %	2053	8	8
Total long-term debt				11,611	10,637
Unamortized debt discount and premium, net				(28)	(27)
Unamortized debt issuance costs				(97)	(92)
Long-term debt due within one year				(250)	—
Long-term debt				$ 11,236	$ 10,518
Long-term debt to financing trust[(b)]					
Subordinated debentures to ComEd Financing III		6.35 %	2033	$ 206	$ 206
Total long-term debt to financing trusts				206	206
Unamortized debt issuance costs				(1)	(1)
Long-term debt to financing trusts				$ 205	$ 205

(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, 2023	December 31, 2022
Long-term debt					
First mortgage bonds[(a)]	2.80 % -	5.95 %	2025 - 2052	$ 5,200	$ 4,625
Loan agreement		2.00 %	2023	—	50
Total long-term debt				5,200	4,675
Unamortized debt discount and premium, net				(24)	(24)
Unamortized debt issuance costs				(42)	(39)
Long-term debt due within one year				—	(50)
Long-term debt				$ 5,134	$ 4,562
Long-term debt to financing trusts[(b)]					
Subordinated debentures to PECO Trust III	7.38 % -	10.50 %	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.

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

BGE

	Rates		Maturity Date	December 31, 2023	December 31, 2022
Long-term debt					
Unsecured notes	2.25 % -	6.35 %	2026 - 2053	$ 4,650	$ 4,250
Total long-term debt				4,650	4,250
Unamortized debt discount and premium, net				(12)	(13)
Unamortized debt issuance costs				(36)	(30)
Long-term debt due within one year				—	(300)
Long-term debt				$ 4,602	$ 3,907

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

PHI

	Rates		Maturity Date	December 31, 2023	December 31, 2022
Long-term debt					
First mortgage bonds[(a)]	1.05 % -	7.90 %	2024 - 2053	$ 7,972	$ 7,397
Senior unsecured notes		7.45 %	2032	185	185
Unsecured tax-exempt bonds	4.15 % -	4.20 %	2024	33	33
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Finance leases		5.62 %	2025 - 2031	74	76
Total long-term debt				8,274	7,701
Unamortized debt discount and premium, net				—	4
Unamortized debt issuance costs				(55)	(47)
Fair value adjustment				429	462
Long-term debt due within one year				(644)	(591)
Long-term debt				$ 8,004	$ 7,529

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(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, 2023	December 31, 2022
Long-term debt					
First mortgage bonds[(a)]	2.32 % -	7.90 %	2024 - 2053	$ 4,125	$ 3,775
Finance leases		5.62 %	2025 - 2031	26	25
Total long-term debt				4,151	3,800
Unamortized debt discount and premium, net				2	2
Unamortized debt issuance costs				(57)	(51)
Long-term debt due within one year				(405)	(4)
Long-term debt				$ 3,691	$ 3,747

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(a) Substantially all of Pepco's assets are subject to the lien of its mortgage indenture.

DPL

	Rates		Maturity Date	December 31, 2023	December 31, 2022
Long-term debt					
First mortgage bonds[(a)]	1.05 % -	5.72 %	2028 - 2053	$ 2,024	$ 1,874
Unsecured tax-exempt bonds	4.15 % -	4.20 %	2024	33	33
Medium-terms notes (unsecured)		7.72 %	2027	10	10
Finance leases		5.62 %	2025 - 2031	29	32
Total long-term debt				2,096	1,949
Unamortized debt discount and premium, net[(b)]				—	—
Unamortized debt issuance costs				(16)	(11)
Long-term debt due within one year				(84)	(584)
Long-term debt				$ 1,996	$ 1,354

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(a) Substantially all of DPL's assets are subject to the lien of its mortgage indenture.
(b) The amount in the Unamortized debt discount and premium, net category was less than $1 million as of December 31, 2023 and 2022.

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

ACE

	Rates		Maturity Date	December 31, 2023	December 31, 2022
Long-term debt					
First mortgage bonds[(a)]	2.25 % -	5.80 %	2024 - 2053	$ 1,823	$ 1,748
Finance leases		5.62 %	2025 - 2031	19	19
Total long-term debt				1,842	1,767
Unamortized debt discount and premium, net				—	(1)
Unamortized debt issuance costs				(9)	(9)
Long-term debt due within one year				(154)	(3)
Long-term debt				$ 1,679	$ 1,754

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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 2024 through 2028 and thereafter are as follows:

Year	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2024	$ 1,403	$ 250	$ —	$ —	$ 644	$ 405	$ 84	$ 154
2025	1,327	—	350	—	166	6	6	154
2026	1,615	500	—	350	15	5	6	4
2027	1,023	350	—	—	22	4	15	3
2028	1,990	550	81	—	358	3	3	352
Thereafter	33,921 (a)	10,167 (b)	4,953 (c)	4,300	7,070	3,728	1,982	1,175
Total	$ 41,279	$ 11,817	$ 5,384	$ 4,650	$ 8,275	$ 4,151	$ 2,096	$ 1,842

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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.

Long-Term Debt to Affiliates

In connection with the debt obligations assumed by Exelon as part of the Constellation merger, Exelon and subsidiaries of Generation (former Constellation subsidiaries) entered into intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes receivable at Exelon Corporate from Generation. In connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle the intercompany loan.

Debt Covenants

As of December 31, 2023, the Registrants are in compliance with debt covenants.

17. 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.

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

- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Fair Value of Financial Liabilities Recorded at Amortized Cost

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) at December 31, 2023 and 2022. The Registrants have no financial liabilities classified as Level 1 or 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, 2023					December 31, 2022				
	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	$ 41,095	$ —	$ 33,804	$ 3,442	$ 37,246	$ 37,074	$ —	$ 29,902	$ 2,327	$ 32,229
ComEd	11,486	—	10,210	—	10,210	10,518	—	9,006	—	9,006
PECO	5,134	—	4,562	—	4,562	4,612	—	3,864	50	3,914
BGE	4,602	—	4,145	—	4,145	4,207	—	3,613	—	3,613
PHI	8,648	—	4,160	3,442	7,602	8,120	—	4,507	2,277	6,784
Pepco	4,096	—	2,311	1,600	3,911	3,751	—	2,229	1,205	3,434
DPL	2,080	—	694	1,134	1,828	1,938	—	1,164	458	1,622
ACE	1,833	—	939	708	1,647	1,757	—	909	614	1,523
Long-Term Debt to Financing Trusts										
Exelon	$ 390	$ —	$ —	$ 390	$ 390	$ 390	$ —	$ —	$ 384	$ 384
ComEd	205	—	—	208	208	205	—	—	204	204
PECO	184	—	—	182	182	184	—	—	180	180

(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 16 — Debt and Credit Agreements for unamortized debt issuance costs, unamortized debt discount and premium, net, and purchase accounting fair value adjustments and Note 10 — Leases for finance lease liabilities.

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.

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, 2023 and 2022. Exelon and the Utility Registrants have immaterial and no financial assets or liabilities measured using the NAV practical expedient, respectively.

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

Exelon

	At December 31, 2023				At December 31, 2022			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[a]	$ 618	$ —	$ —	$ 618	$ 664	$ —	$ —	$ 664
Rabbi trust investments								
Cash equivalents	67	—	—	67	62	—	—	62
Mutual funds	53	—	—	53	49	—	—	49
Fixed income	—	7	—	7	—	7	—	7
Life insurance contracts	—	61	43	104	—	58	40	98
Rabbi trust investments subtotal	120	68	43	231	111	65	40	216
Interest rate derivative assets								
Derivatives designated as hedging instruments	—	11	—	11	—	6	—	6
Economic hedges	—	1	—	1	—	5	—	5
Interest rate derivative assets subtotal	—	12	—	12	—	11	—	11
Total assets	738	80	43	861	775	76	40	891
Liabilities								
Commodity derivative liabilities	—	—	(133)	(133)	—	—	(84)	(84)
Interest rate derivative liabilities								
Derivatives designated as hedging instruments	—	(24)	—	(24)	—	(4)	—	(4)
Economic hedges	—	(22)	—	(22)	—	(3)	—	(3)
Interest rate derivative liabilities subtotal	—	(46)	—	(46)	—	(7)	—	(7)
Deferred compensation obligation	—	(75)	—	(75)	—	(75)	—	(75)
Total liabilities	—	(121)	(133)	(254)	—	(82)	(84)	(166)
Total net assets (liabilities)	$ 738	$ (41)	$ (90)	$ 607	$ 775	$ (6)	$ (44)	$ 725

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(a) Excludes cash of $334 million and $345 million at December 31, 2023 and 2022, respectively, and restricted cash of $149 million and $81 million at December 31, 2023 and 2022, respectively, and includes long-term restricted cash of $174 million and $117 million at December 31, 2023 and 2022, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

ComEd, PECO, and BGE

	ComEd				PECO				BGE			
At December 31, 2023	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]	$ 453	$ —	$ —	$ 453	$ 9	$ —	$ —	$ 9	$ —	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	9	—	—	9
Life insurance contracts	—	—	—	—	—	18	—	18	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	18	—	27	9	—	—	9
Total assets	453	—	—	453	18	18	—	36	9	—	—	9
Liabilities												
Commodity derivative liabilities[b]	—	—	(133)	(133)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(8)	—	(8)	—	(4)	—	(4)
Total liabilities	—	(8)	(133)	(141)	—	(8)	—	(8)	—	(4)	—	(4)
Total net assets (liabilities)	$ 453	$ (8)	$ (133)	$ 312	$ 18	$ 10	$ —	$ 28	$ 9	$ (4)	$ —	$ 5

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

At December 31, 2022	ComEd				PECO				BGE			
	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)]	$ 392	$ —	$ —	$ 392	$ 10	$ —	$ —	$ 10	$ 23	$ —	$ —	$ 23
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	7	—	—	7
Life insurance contracts	—	—	—	—	—	15	—	15	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	7	15	—	22	7	—	—	7
Total assets	392	—	—	392	17	15	—	32	30	—	—	30
Liabilities												
Commodity derivative liabilities[(b)]	—	—	(84)	(84)	—	—	—	—	—	—	—	—
Deferred compensation obligation	—	(8)	—	(8)	—	(7)	—	(7)	—	(4)	—	(4)
Total liabilities	—	(8)	(84)	(92)	—	(7)	—	(7)	—	(4)	—	(4)
Total net assets (liabilities)	$ 392	$ (8)	$ (84)	$ 300	$ 17	$ 8	$ —	$ 25	$ 30	$ (4)	$ —	$ 26

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(a) ComEd excludes cash of $86 million and $42 million at December 31, 2023 and 2022, respectively, and restricted cash of $147 million and $77 million at December 31, 2023 and 2022, respectively, and includes long-term restricted cash of $174 million and $117 million at December 31, 2023 and 2022, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $42 million and $58 million at December 31, 2023 and 2022, respectively. BGE excludes cash of $47 million and $43 million at December 31, 2023 and 2022, respectively, and restricted cash of $1 million and $1 million at December 31, 2023 and 2022, respectively.
(b) The Level 3 balance consists of the current and noncurrent liability of $27 million and $106 million, respectively, at December 31, 2023, and $5 million and $79 million, respectively, at December 31, 2022 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

PHI, Pepco, DPL, and ACE

PHI	At December 31, 2023				At December 31, 2022			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$ 107	$ —	$ —	$ 107	$ 205	$ —	$ —	$ 205
Rabbi trust investments								
Cash equivalents	64	—	—	64	59	—	—	59
Mutual funds	9	—	—	9	11	—	—	11
Fixed income	—	7	—	7	—	7	—	7
Life insurance contracts	—	21	41	62	—	22	39	61
Rabbi trust investments subtotal	73	28	41	142	70	29	39	138
Total assets	180	28	41	249	275	29	39	343
Liabilities								
Deferred compensation obligation	—	(13)	—	(13)	—	(14)	—	(14)
Total liabilities	—	(13)	—	(13)	—	(14)	—	(14)
Total net assets	$ 180	$ 15	$ 41	$ 236	$ 275	$ 15	$ 39	$ 329

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

	Pepco				DPL				ACE			
At December 31, 2023	**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)]	$ 23	$ —	$ —	$ 23	$ 1	$ —	$ —	$ 1	$ —	$ —	$ —	$ —
Rabbi trust investments												
Cash equivalents	63	—	—	63	—	—	—	—	—	—	—	—
Life insurance contracts	—	21	41	62	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	63	21	41	125	—	—	—	—	—	—	—	—
Total assets	86	21	41	148	1	—	—	1	—	—	—	—
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	$ 86	$ 20	$ 41	$ 147	$ 1	$ —	$ —	$ 1	$ —	$ —	$ —	$ —

	Pepco				DPL				ACE			
At December 31, 2022	**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)]	$ 51	$ —	$ —	$ 51	$ 121	$ —	$ —	$ 121	$ 1	$ —	$ —	$ 1
Rabbi trust investments												
Cash equivalents	59	—	—	59	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	38	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	59	22	38	119	—	—	—	—	—	—	—	—
Total assets	110	22	38	170	121	—	—	121	1	—	—	1
Liabilities												
Deferred compensation obligation	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total liabilities	—	(1)	—	(1)	—	—	—	—	—	—	—	—
Total net assets	$ 110	$ 21	$ 38	$ 169	$ 121	$ —	$ —	$ 121	$ 1	$ —	$ —	$ 1

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(a) PHI excludes cash of $96 million and $165 million at December 31, 2023 and 2022, respectively, and restricted cash of $1 million and $3 million at December 31, 2023 and 2022, respectively. Pepco excludes cash of $48 million and $45 million at December 31, 2023 and 2022, respectively, and restricted cash of $1 million and $3 million at December 31, 2023 and 2022, respectively. DPL excludes cash of $15 million and $31 million at December 31, 2023 and 2022, respectively. ACE excludes cash of $21 million and $71 million at December 31, 2023 and 2022, respectively.

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, 2023 and 2022:

	Exelon	ComEd	PHI and Pepco
For the year ended December 31, 2023	**Total**	**Commodity Derivatives**	**Life Insurance Contracts**
Balance at December 31, 2022	$ (44)	$ (84)	$ 40
Total realized / unrealized gains (losses)			
Included in net income[(a)]	3	—	1
Included in regulatory assets/liabilities	(49)	(49) [(b)]	—
Balance at December 31, 2023	$ (90)	$ (133) [(c)]	$ 41
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, 2023	$ 3	$ —	$ 1

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

	Exelon	ComEd	PHI and Pepco
For the year ended December 31, 2022	Total	Commodity Derivatives	Life Insurance Contracts
Balance at December 31, 2021	$ (182)	$ (219)	$ 35
Total realized / unrealized gains (losses)			
Included in net income[(a)]	5	—	5
Included in regulatory assets/liabilities	135	135 [(b)]	—
Transfers into Level 3	(2)	—	—
Balance at December 31, 2022	$ (44)	$ (84)	$ 40
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, 2022	$ 5	$ —	$ 5

(a) Classified in Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income.
(b) Includes $83 million of decreases in fair value and an increase for realized gains due to settlements of $34 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2023. Includes $136 million of increases in fair value and a decrease for realized losses due to settlements of $1 million recorded in Purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2022.
(c) The balance of the current and noncurrent asset was effectively zero as of December 31, 2023. The balance consists of a current and noncurrent liability of $27 million and $106 million, respectively, as of December 31, 2023.

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, Pepco, DPL, and ACE). 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.

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. These interest rate swaps are typically accounted for as economic hedges. In addition, Exelon may utilize interest rate derivatives to lock in interest rate 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 15 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

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

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 15 — 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, 2023	Fair Value as of December 31, 2022	Valuation Technique	Unobservable Input	2023 Range & Arithmetic Average			2022 Range & Arithmetic Average		
Commodity derivatives	$ (133)	$ (84)	Discounted Cash Flow	Forward power price[(a)]	$ 30.27	- $ 73.71	$ 43.35	$ 34.78	- $ 75.71	$ 48.44

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(a) An increase to the forward power price would increase the fair value.

18. 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, 2023:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	38	35	31	3	1

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(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, 2023, representing commitments potentially triggered by future events were as follows:

		Expiration within					
Exelon	Total	2024	2025	2026	2027	2028	2029 and beyond
Letters of credit[a]	$ 29	$ 27	$ 2	$ —	$ —	$ —	$ —
Surety bonds[b]	204	204	—	—	—	—	—
Financing trust guarantees[c]	378	—	—	—	—	78	300
Guaranteed lease residual values[d]	27	—	5	6	4	6	6
Total commercial commitments	$ 638	$ 231	$ 7	$ 6	$ 4	$ 84	$ 306
ComEd							
Letters of credit[a]	$ 17	$ 15	$ 2	$ —	$ —	$ —	$ —
Surety bonds[b]	46	46	—	—	—	—	—
Financing trust guarantees[c]	200	—	—	—	—	—	200
Total commercial commitments	$ 263	$ 61	$ 2	$ —	$ —	$ —	$ 200
PECO							
Letters of credit[a]	$ 1	$ 1	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	2	2	—	—	—	—	—
Financing trust guarantees[c]	178	—	—	—	—	78	100
Total commercial commitments	$ 181	$ 3	$ —	$ —	$ —	$ 78	$ 100
BGE							
Letters of credit[a]	$ 8	$ 8	$ —	$ —	$ —	$ —	$ —
Surety bonds[b]	3	3	—	—	—	—	—
Total commercial commitments	$ 11	$ 11	$ —	$ —	$ —	$ —	$ —
PHI							
Surety bonds[b]	$ 96	$ 96	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[d]	27	—	5	6	4	6	6
Total commercial commitments	$ 123	$ 96	$ 5	$ 6	$ 4	$ 6	$ 6
Pepco							
Surety bonds[b]	$ 84	$ 84	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[d]	9	—	2	2	1	2	2
Total commercial commitments	$ 93	$ 84	$ 2	$ 2	$ 1	$ 2	$ 2
DPL							
Surety bonds[b]	$ 7	$ 7	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[d]	11	—	2	3	2	2	2
Total commercial commitments	$ 18	$ 7	$ 2	$ 3	$ 2	$ 2	$ 2
ACE							
Surety bonds[b]	$ 5	$ 5	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[d]	7	—	1	1	1	2	2
Total commercial commitments	$ 12	$ 5	$ 1	$ 1	$ 1	$ 2	$ 2

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(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 that 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 $61 million guaranteed by Exelon and PHI, of which $20 million, $24 million, and $17 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 17 sites that are 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 2031.
- PECO has 6 sites that are 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 2025.
- BGE has 4 sites that currently require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2025.
- DPL has 1 site that is 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 completion 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 2023, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The study resulted in a $25 million increase to the environmental liability and related regulatory asset for ComEd.

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

The increase was primarily due to increased costs resulting from inflation and changes in remediation plans. The study did not result in a material change to the environmental liability for PECO.

At December 31, 2023 and 2022, 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, 2023		December 31, 2022	
	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	$ 428	$ 338	$ 409	$ 355
ComEd	303	302	325	324
PECO	27	25	25	23
BGE	14	11	9	8
PHI	81	—	46	—
Pepco	79	—	44	—
DPL	1	—	1	—
ACE	1	—	1	—

Benning Road Site (Exelon, PHI, and Pepco). In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site, 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 Generation, 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 DOEE approved on February 3, 2020. The Pepco Entities are completing a FS to evaluate possible remedial alternatives for submission to DOEE. In October, 2022, 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. It is currently anticipated that the landside FS will be complete and approved by DOEE by the end of the first quarter of 2024 and the waterside FS will be complete and approved by DOEE by the end of the fourth quarter of 2024. Following the completion of each FS, DOEE will issue a Proposed Plan for public comment and then issue a Record of Decision (ROD) identifying the remedial actions determined to be necessary for the area in question. On October 3, 2023, 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 DOEE for the landslide and water areas. This addendum to the Benning Consent Decree has been lodged with the court in January 2024. Once the addendum is signed and entered by the court it will become effective.

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/Generation 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, 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 river-wide 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 DOEE's contractor.

On September 30, 2020, 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 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 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 to enter into settlement discussions. On October 3, 2023, 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 river-wide RI/FS and all future costs to complete the work required by the Interim ROD. This amount will be paid in four equal annual installments beginning a year after the effective date of the Anacostia River Consent Decree. The funds will be 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 contribution from other potentially responsible parties. The Anacostia River Consent Decree was lodged with the U.S. District Court for the District of Columbia in January 2024. Once the court signs and approves the Anacostia River Consent Decree it will become effective. 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 very early stage of the NRD process, Pepco cannot reasonably estimate the final range of loss potentially resulting from this process.

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 (ARSP) 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. On October 3, 2023, 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 Consent Order was lodged with the District of Columbia Superior Court in January 2024. The court signed and entered the Consent Order, and it became effective on February 2, 2024. Exelon, PHI, and Pepco have accrued a liability for the penalty payments and for the projected costs for the required environmental assessments and remediation. Pepco has concluded that incremental exposure is reasonably possible, but the range of loss cannot be reasonably estimated beyond the amounts 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 (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 48% as calculated pursuant to the MDPSC's and DCPSC's ratemaking precedents, of 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 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 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 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 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. On October 22, 2019, the SEC notified Exelon and ComEd that it had also opened an investigation into their lobbying activities. On July 17, 2020, ComEd entered into a DPA with the USAO to resolve the USAO investigation. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the former Speaker of the Illinois House of Representatives and the Speaker's associates, with the intent to influence the Speaker's action regarding legislation affecting ComEd's interests. The DPA provided that the USAO would defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including payment to the U.S. Treasury of $200 million, which was paid in November 2020. Exelon was not made a party to the DPA, and therefore the investigation by the USAO into Exelon's activities ended with no charges being brought against Exelon. 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.

On September 28, 2023, Exelon and ComEd reached a settlement with the SEC, concluding and resolving in its entirety the SEC investigation, which related to the conduct identified in the DPA that was entered into by ComEd in July 2020 and successfully exited in July 2023. Under the terms of the settlement, Exelon agreed to pay a civil penalty of $46.2 million and Exelon and ComEd agreed to cease and desist from committing or causing any violations and any future violations of specified provisions of the federal securities laws and rules promulgated thereunder. Exelon recorded an accrual for the full amount of the penalty in the second quarter of 2023, which was reflected in Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and in Accrued expenses on the Consolidated Balance Sheets. Exelon paid the civil penalty in full on October 4, 2023.

Subsequent to Exelon announcing the receipt of the subpoenas, various lawsuits were filed, and various demand letters were received related to the subject of the subpoenas and, the conduct described in the DPA and the SEC's investigation, including:

- Four putative class action lawsuits against ComEd and Exelon were filed in federal court on behalf of ComEd customers in the third quarter of 2020 alleging, among other things, civil violations of federal racketeering laws. In addition, the Citizens Utility Board (CUB) filed a motion to intervene in these cases on October 22, 2020 which was granted on December 23, 2020. On September 9, 2021, the federal court granted Exelon's and ComEd's motion to dismiss and dismissed the plaintiffs' and CUB's federal law claim with prejudice. The federal court also dismissed the related state law claims made by the federal plaintiffs and CUB on jurisdictional grounds. Plaintiffs appealed dismissal of the federal law claim to the Seventh Circuit Court of Appeals. Plaintiffs and CUB also refiled their state law claims in state court and moved to consolidate them with the already pending consumer state court class action, discussed below. On August 22, 2022, the Seventh Circuit affirmed the dismissal of the consolidated federal cases in their entirety. The time to further appeal has passed and the Seventh Circuit's decision is final.
- Three putative class action lawsuits against ComEd and Exelon were filed in Illinois state court in the third quarter of 2020 seeking restitution and compensatory damages on behalf of ComEd customers. The cases were consolidated into a single action in October of 2020. In November 2020, CUB filed a motion to intervene in the cases pursuant to an Illinois statute allowing CUB to intervene as a party or otherwise participate on behalf of utility consumers in any proceeding which affects the interest of utility consumers. On November 23, 2020, the court allowed CUB's intervention, but denied CUB's request to stay these cases. Plaintiffs subsequently filed a consolidated complaint, and ComEd and Exelon filed a motion to dismiss on jurisdictional and substantive grounds on January 11, 2021. Briefing on that motion was completed on March 2, 2021. The parties agreed, on March 25, 2021, along with the federal court plaintiffs discussed above, to jointly engage in mediation. The parties participated in a one-day mediation on June 7, 2021 but no settlement was reached. On December 23, 2021, the state court granted ComEd and Exelon's motion to dismiss with prejudice. On December 30, 2021, plaintiffs filed a motion to reconsider that dismissal and for permission to amend their complaint. The court denied the plaintiffs' motion on January 21, 2022. Plaintiffs have appealed the court's ruling dismissing their complaint to the First District Court of Appeals. On February 15, 2022, Exelon and ComEd moved to dismiss the federal plaintiffs' refiled state law claims, seeking dismissal on the same legal grounds asserted in their motion to dismiss the original state court plaintiffs' complaint. The court granted dismissal of the refiled state claims on February 16, 2022. The original federal plaintiffs appealed that dismissal on February 18, 2022. The two state appeals were consolidated on March 21, 2022. On September 8, 2023, the Illinois appellate court affirmed the dismissal. Plaintiffs have asked the Illinois Supreme Court to grant them leave to further appeal, but such appeal is not allowed as a matter of right.

Exelon and ComEd filed a response in opposition to the request for leave to further appeal on January 12, 2024.

- On November 3, 2022, a plaintiff filed a putative class action complaint in Lake County, Illinois Circuit Court against ComEd and Exelon for unjust enrichment and deceptive business practices in connection with the conduct giving rise to the DPA. Plaintiff seeks an accounting and disgorgement of any benefits ComEd allegedly obtained from said conduct. Plaintiff served initial discovery requests on ComEd in December 2022, to which ComEd has responded. ComEd and Exelon filed a motion to dismiss the Complaint on February 3, 2023. On June 16, 2023, the court granted Exelon and ComEd's motion to dismiss the action with prejudice. Plaintiff filed its notice of appeal of that dismissal on July 17, 2023. Plaintiff's opening appellate brief was filed on October 19, 2023. ComEd and Exelon filed a response on January 2, 2024. Plaintiff filed its reply brief on February 2, 2024. With leave of court, Exelon and ComEd filed a sur-reply on February 14, 2024. The appellate court has set oral argument for April 3, 2024.
- A putative class action lawsuit against Exelon and certain officers of Exelon and ComEd was filed in federal court in December 2019 alleging misrepresentations and omissions in Exelon's SEC filings related to ComEd's lobbying activities and the related investigations. The complaint was amended on September 16, 2020, to dismiss two of the original defendants and add other defendants, including ComEd. Defendants filed a motion to dismiss in November 2020. The court denied the motion in April 2021. On May 26, 2021, defendants moved the court to certify its order denying the motion to dismiss for interlocutory appeal. Briefing on the motion was completed in June 2021, and that motion was denied on January 28, 2022. In May 2021, the parties each filed respective initial discovery disclosures. On June 9, 2021, defendants filed their answer and affirmative defenses to the complaint and the parties engaged thereafter in discovery. On September 9, 2021, the U.S. government moved to intervene in the lawsuit and stay discovery until the parties entered into an amendment to their protective order that would prohibit the parties from requesting discovery into certain matters, including communications with the U.S. government. The court ordered said amendment to the protective order on November 15, 2021 and discovery resumed. The court further amended the protective order on October 17, 2022 and extended it until May 15, 2023. Following mediation, the parties reached a settlement of the lawsuit, under which defendants agreed to pay plaintiffs $173 million. On May 26, 2023, plaintiffs filed a motion for preliminary approval of the settlement, which the court granted on June 9, 2023. The court granted final settlement approval on September 7, 2023. The settlement was fully covered by insurance and has been paid in full.
- Several shareholders have sent letters to the Exelon Board of Directors since 2020 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. On October 12, 2021, the parties to the derivative action filed an agreed motion to stay that litigation for 120 days in order to allow the SLC to continue its investigation, which the court granted. The stay has been extended several times. The parties participated in a mediation in February 2023, but the matter did not resolve at that time. On April 26 and May 1, 2023, two additional demand letter shareholders each filed a separate derivative lawsuit against current and former Exelon and ComEd officers and directors, and certain third parties, and against Exelon as nominal defendant, asserting claims similar to those made in their respective demand letters. On May 25, 2023, certain demand letter shareholders (Settling Shareholders) filed a separate derivative lawsuit against current and former Exelon and ComEd officers and directors, and against Exelon as nominal defendant, asserting claims similar to those made in their respective demand letters. The then pending derivative lawsuits were subsequently consolidated. On May 26, 2023, prior to lawsuit consolidation, the SLC filed a Notice of Determination and Intent to Seek Court Approval of Settlement (Notice of Determination). The Notice of Determination stated that, through mediation efforts, a settlement of the derivative claims had been approved 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 the Settling Shareholders (the Settling Parties). The Notice of Determination further specified the process by which the Settling Parties would seek court approval of the proposed settlement and resolution and dismissal of all derivative claims and lawsuits, including any lawsuits or actions brought by demand letter shareholders who are not participating in the proposed settlement. In furtherance of the proposed settlement, on June 16, 2023, the SLC filed a motion for preliminary approval of the settlement, attaching the Stipulation and Agreement of Settlement (Stipulation), which contains 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. On June 13, 2023, the non-settling derivative shareholders filed a motion asking the court to set a status conference to discuss lifting the discovery stay. On June 29, 2023, an additional shareholder filed a separate derivative lawsuit against current and former Exelon and ComEd officers and directors, and against Exelon as nominal defendant, asserting claims similar to those made in its demand letter. That lawsuit has been consolidated into the other pending derivative lawsuits. On June 30, 2023, the non-settling shareholders' motion for status and the SLC's motion for preliminary approval was heard by the court, during which the court set a briefing schedule on the appropriate standard for evaluating the settlement and the proper scope of requested discovery. Following briefing and a hearing, the court allowed the non-settling shareholders to seek certain, limited discovery, which the SLC, Independent Review Committee, and Exelon responded to on October 5, 2023. On October 11, 2023, an additional non-settling shareholder filed a separate derivative lawsuit against current and former Exelon and ComEd officers and directors, and against Exelon as a nominal defendant, asserting claims similar to those made in its demand letter. That lawsuit has been consolidated into the other pending derivative lawsuits. The SLC filed its renewed motion for preliminary approval on October 26, 2023, with supporting submissions filed by the Independent Review Committee, Exelon, and the settling shareholders on that same day. The non-settling plaintiffs filed a response to the renewed motion for preliminary approval and supporting submissions on November 29, 2023, and the SLC Independent Review Committee, Exelon and the Settling Shareholders filed their respective reply briefs on December 21, 2023. On January 16, 2024, the non-settling plaintiffs sought leave of court to file a sur-reply, which the court granted on January 18, 2024.

In August 2022, the ICC concluded its investigation initiated on August 12, 2021 into rate impacts of conduct admitted in the DPA, including the costs recovered from customers related to the DPA and Exelon's funding of the fine paid by ComEd. On August 17, 2022, the ICC issued its final order accepting ComEd's voluntary customer refund offer of approximately $38 million (of which about $31 million is ICC jurisdictional; the remaining balance is FERC jurisdictional) that resolves the question of whether customer funds were used for DPA related activities. The customer refund includes the cost of every individual or entity that was either (i) identified in the DPA or (ii) identified by ComEd as an associate of the former Speaker of the Illinois House of Representatives in the ICC proceeding. The ICC's DPA investigation is now closed. The ICC jurisdictional refund was made to customers during the April 2023 billing cycle, as required by the ICC. The FERC jurisdictional refund was included in ComEd's transmission formula rate update proceeding, filed on May 12, 2023. The filed transmission rate, inclusive of the FERC jurisdictional DPA refund, will appear on ComEd retail customers' bills for the June 2023 through May 2024 monthly billing periods, in the line designated as "Transmission Services Charge." The customer refund will not be recovered in rates or charged to customers and ComEd will not seek or accept reimbursement or indemnification from any source other than Exelon. An accrual for the amount of the customer refund has been recorded in Regulatory assets in Exelon's and ComEd's Consolidated Balance Sheets as of December 31, 2023.

Savings Plan Claim (Exelon). On December 6, 2021, seven current and former employees filed a putative ERISA class action suit in U.S. District Court for the Northern District of Illinois against Exelon, its Board of Directors, the former Board Investment Oversight Committee, the Corporate Investment Committee, individual defendants, and other unnamed fiduciaries of the Exelon Corporation Employee Savings Plan (Plan). The complaint alleges that the defendants violated their fiduciary duties under the Plan by including certain investment options that allegedly were more expensive than and underperformed similar passively-managed or other funds available in the marketplace and permitting a third-party administrative service provider/recordkeeper and an investment adviser to charge excessive fees for the services provided. The plaintiffs seek declaratory, equitable and monetary relief on behalf of the Plan and participants. On February 16, 2022, the court granted the parties' stipulated dismissal of the individual named defendants without prejudice. The remaining defendants filed a motion to dismiss the complaint on February 25, 2022. On March 4, 2022, the Chamber of Commerce filed a brief of amicus curiae in support of the defendants' motion to dismiss. On September 22, 2022, the court granted Exelon's motion to dismiss without prejudice. The court granted plaintiffs leave until October 31, 2022 to file an amended complaint, which was later extended to November 30, 2022. Plaintiffs filed their amended complaint on November 30, 2022. Defendants filed their motion to dismiss the amended complaint on January 20, 2023. On September 29, 2023, the court again granted Exelon's motion to dismiss but granted plaintiffs leave until October 20, 2023 to file a second amended complaint. Plaintiffs did not file an amended complaint by the deadline. On October 25, 2023, the parties filed a joint Stipulation of Dismissal, which provides that plaintiffs agreed that they will not initiate an appeal from the dismissal of this matter, and the parties agree that each side shall bear their own costs and attorneys' fees. Plaintiffs also acknowledge in the Stipulation that defendants have neither paid nor agreed to pay or provide any monetary or equitable remedy in connection with the dismissal of this action. On October 27, 2023, the court entered final judgment dismissing the matter with prejudice. No loss contingencies have been reflected in Exelon's consolidated financial statements with respect to this matter.

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.

19. Shareholders' Equity (All Registrants)

Equity Securities Offering (Exelon)

On August 4, 2022, Exelon entered into an agreement with certain underwriters in connection with an underwritten public offering (the "Offering") of 11.3 million shares (the "Shares") of its Common stock, no par value ("Common Stock"). The Shares were sold to the underwriters at a price per share of $43.32. Exelon also granted the underwriters an option to purchase an additional 1.695 million shares of Common stock also at the price per share of $43.32. On August 5, 2022, the underwriters exercised the option in full. The net proceeds from the Offering and the exercise of the underwriters' option were $563 million before expenses paid by Exelon. Exelon used the proceeds, together with available cash balances, to repay $575 million in borrowings under a $1.15 billion term loan credit facility. See Note 16 — Debt and Credit Agreements for additional information on Exelon's term loan.

At-the-Market Program (Exelon)

On August 4, 2022, Exelon executed an equity distribution agreement ("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 $1.0 billion. Exelon has no obligation to offer or sell any shares of Common stock under the Equity Distribution Agreement and may, at any time, suspend or terminate offers and sales under the Equity Distribution Agreement. In November and December 2023, Exelon issued approximately 3.6 million shares of Common stock at an average gross price of $39.58 per share. The net proceeds from these issuances were $140 million, which were used for general corporate purposes. As of December 31, 2023, $858 million of Common stock remained available for sale pursuant to the ATM program.

ComEd Common Stock Warrants

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

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,	
	2023	2022
Warrants outstanding	60,032	60,052
Common Stock reserved for conversion	20,011	20,017

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, 2023 and 2022. 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, 2023 and 2022.

The following table presents ComEd, BGE, and ACE's preference securities authorized, none of which were outstanding as of December 31, 2023 and 2022. 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, 2023 and 2022.

20. Stock-Based Compensation Plans (All Registrants)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards, restricted stock units, and stock options. At December 31, 2023, there were approximately 33 million shares authorized for issuance under the LTIP. For the years ended December 31, 2023, 2022, and 2021, exercised and distributed stock-based awards were primarily issued from authorized but unissued Common stock shares.

Separation-related Adjustments. In connection with the separation, Exelon and Constellation entered into an Employee Matters Agreement, effective February 1, 2022. Under the terms of the Employee Matters Agreement, and pursuant to the terms of the LTIP, the Compensation Committee of the Board of Exelon approved an adjustment to outstanding awards granted under the LTIP in order to preserve the intrinsic aggregate value of such awards before the separation. The separation-related adjustments did not have a material impact on either compensation expense or the potentially dilutive securities to be considered in the calculation of diluted earnings per share of Common stock. Former Exelon employees transferred to Constellation as a result of the separation surrendered their outstanding unvested Exelon awards effective February 1, 2022.

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

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, 2023, 2022, and 2021 was not material.

	Year Ended December 31,		
Exelon	**2023**	**2022**	**2021**
Total stock-based compensation expense included in Operating and maintenance expense	$ 21	$ 41	$ 95
Income tax benefit	(5)	(10)	(25)
Total after-tax stock-based compensation expense	$ 16	$ 31	$ 70

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and 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,		
	2023	**2022**	**2021**
Performance share awards	$ 8	$ 6	$ 6
Restricted stock units	6	6	6

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards 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. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon's nonvested performance share awards activity:

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

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2022[(a)]	866,805	$ 41.86
Granted	679,196	41.82
Change in performance	(1,233)	41.75
Vested	(261,577)	41.25
Forfeited	(112,727)	41.96
Undistributed vested awards[(b)]	(212,222)	41.61
Nonvested at December 31, 2023[(a)]	958,242	$ 42.01

(a) Excludes 1,198,093 and 1,539,819 of performance share awards issued to retirement-eligible employees as of December 31, 2023 and 2022, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2023

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,		
	2023[(a)]	2022	2021
Weighted average grant date fair value (per share)	$ 41.82	$ 43.05	$ 43.37
Total fair value of performance shares vested	17	29	44
Total fair value of performance shares settled in cash	26	25	28

(a) As of December 31, 2023, $11 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. The value of the restricted stock units granted to retirement-eligible employees is either recognized ratably over the first six months in the year of grant if the employee reaches retirement eligibility prior to July 1st of the grant year or through the date of which the employee reaches retirement eligibility. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon’s nonvested restricted stock unit activity:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2022[(a)]	561,161	$ 41.98
Granted	385,065	41.84
Vested	(246,618)	42.36
Forfeited	(55,371)	40.56
Undistributed vested awards[(b)]	(112,292)	41.87
Nonvested at December 31, 2023[(a)]	531,945	$ 42.87

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

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(a) Excludes 205,855 and 476,592 of restricted stock units issued to retirement-eligible employees as of December 31, 2023 and 2022, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2023.

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,		
	2023[a]	2022	2021
Weighted average grant date fair value (per share)	$ 41.84	$ 42.97	$ 44.21
Total fair value of restricted stock units vested	15	23	34

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(a) As of December 31, 2023, $9 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 1.6 years.

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted through 2012 under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Stock options will expire no later than ten years from the date of grant.

There were no stock options granted during the year ended December 31, 2023. All stock options were vested and exercised as of December 31, 2022.

The following table summarizes additional information regarding stock options exercised:

	Year Ended December 31,		
	2023	2022	2021
Intrinsic value[a]	$ —	$ —	$ 11
Cash received for exercise price	—	1	37

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(a) The difference between the market value on the date of exercise and the option exercise price.

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

21. 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)]	Foreign Currency Items	Total
Balance at December 31, 2020	$ (5)	$ (3,372)	$ (23)	$ (3,400)
OCI before reclassifications	(1)	432	—	431
Amounts reclassified from AOCI	—	219	—	219
Net current-period OCI	$ (1)	$ 651	$ —	$ 650
Balance at December 31, 2021	$ (6)	$ (2,721)	$ (23)	$ (2,750)
Separation of Constellation	6	1,994	23	2,023
OCI before reclassifications	2	46	—	48
Amounts reclassified from AOCI	—	41	—	41
Net current-period OCI	$ 2	$ 87	$ —	$ 89
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)

(a) This AOCI component is included in the computation of net periodic pension and OPEB cost. Additionally, as of February 1, 2022, in connection with the separation, Exelon's pension and OPEB plans were remeasured. See Note 14 — Retirement Benefits for additional information. See Exelon's Statements of Operations and Comprehensive Income for individual components of AOCI.

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,		
	2023	2022	2021
Pension and non-pension postretirement benefit plans:			
Prior service benefits reclassified to periodic benefit cost	$ —	$ —	$ 4
Actuarial losses reclassified to periodic benefit cost	(8)	(14)	(76)
Pension and non-pension postretirement benefit plans valuation adjustments	33	(14)	(153)
Unrealized gains on cash flow hedges	2	—	—

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

22. 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, 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
For the Year Ended December 31, 2022								
Utility[(a)]	$ 878	$ 306	$ 166	$ 94	$ 312	$ 283	$ 25	$ 4
Property	377	31	17	191	138	94	42	2
Payroll	117	28	16	17	25	6	4	3
For the Year Ended December 31, 2021								
Utility[(a)]	$ 774	$ 246	$ 139	$ 88	$ 301	$ 278	$ 22	$ 3
Property	364	39	18	176	131	88	40	3
Payroll	124	27	16	18	27	7	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, 2023								
AFUDC—Equity	$ 151	$ 33	$ 31	$ 16	$ 71	$ 54	$ 10	$ 7
Non-service net periodic benefit cost	(18)	—	—	—	—	—	—	—
For the Year Ended December 31, 2022								
AFUDC—Equity	$ 150	$ 35	$ 31	$ 21	$ 63	$ 48	$ 7	$ 8
Non-service net periodic benefit cost	63	—	—	—	—	—	—	—
For the Year Ended December 31, 2021								
AFUDC—Equity	$ 136	$ 34	$ 26	$ 27	$ 49	$ 40	$ 6	$ 3
Non-service net periodic benefit cost	91	—	—	—	—	—	—	—

(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[(a)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
For the Year Ended December 31, 2023								
Property, plant, and equipment[(b)]	$ 2,778	$ 1,095	$ 383	$ 509	$ 737	$ 311	$ 208	$ 195
Amortization of regulatory assets[(b)]	720	308	14	145	253	130	36	88
Amortization of intangible assets, net[(b)]	8	—	—	—	—	—	—	—
Total depreciation and amortization	$ 3,506	$ 1,403	$ 397	$ 654	$ 990	$ 441	$ 244	$ 283
For the Year Ended December 31, 2022								
Property, plant, and equipment[(b)]	$ 2,690	$ 1,031	$ 359	$ 476	$ 680	$ 288	$ 191	$ 173
Amortization of regulatory assets[(b)]	718	292	14	154	258	129	41	88
Amortization of intangible assets, net[(b)]	12	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(c)]	3	—	—	—	—	—	—	—
Nuclear fuel[(d)]	66	—	—	—	—	—	—	—
ARO accretion[(e)]	44	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 3,533	$ 1,323	$ 373	$ 630	$ 938	$ 417	$ 232	$ 261
For the Year Ended December 31, 2021								
Property, plant, and equipment[(b)]	$ 5,384	$ 970	$ 336	$ 439	$ 627	$ 274	$ 169	$ 155
Amortization of regulatory assets[(b)]	594	235	12	152	194	129	41	24
Amortization of intangible assets, net[(b)]	58	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(c)]	31	—	—	—	—	—	—	—
Nuclear fuel[(d)]	992	—	—	—	—	—	—	—
ARO accretion[(e)]	514	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 7,573	$ 1,205	$ 348	$ 591	$ 821	$ 403	$ 210	$ 179

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(a) Exelon's 2022 and 2021 amounts include amounts related to Generation prior to the separation. See Note 2 — Discontinued Operations for additional information.
(b) Included in Depreciation and amortization in the Registrants' Consolidated Statements of Operations and Comprehensive Income.
(c) Included in Electric operating revenues or Purchased power expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.
(d) Included in Purchased fuel expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.
(e) Included in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income.

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

	Cash paid (refunded) during the year							
	Exelon[(a)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
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
For the Year Ended December 31, 2022								
Interest (net of amount capitalized)	$ 1,434	$ 396	$ 166	$ 147	$ 274	$ 141	$ 63	$ 60
Income taxes (net of refunds)	73	23	31	16	19	28	(2)	(6)
For the Year Ended December 31, 2021								
Interest (net of amount capitalized)	$ 1,505	$ 372	$ 152	$ 134	$ 255	$ 132	$ 59	$ 56
Income taxes (net of refunds)	281	(72)	(4)	(38)	—	12	(9)	2

(a) Exelon's 2022 and 2021 amounts include amounts related to Generation prior to the separation. See Note 2 — Discontinued Operations for additional information.

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

	Other non-cash operating activities							
	Exelon[(a)]	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
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[(b)]	(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)
For the Year Ended December 31, 2022								
Pension and OPEB costs (benefit)	$ 164	$ 60	$ (9)	$ 44	$ 53	$ 9	$ 3	$ 12
Allowance for credit losses	173	46	45	25	58	29	12	16
Other decommissioning-related activity	36	—	—	—	—	—	—	—
Energy-related options	60	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates[(b)]	(168)	(267)	(2)	47	54	31	7	16
Long-term incentive plan	42	—	—	—	—	—	—	—
Amortization of operating ROU asset	56	2	—	14	27	7	8	3
AFUDC - Equity	(150)	(35)	(31)	(21)	(63)	(48)	(7)	(8)
For the Year Ended December 31, 2021								
Pension and OPEB costs	$ 411	$ 129	$ 8	$ 61	$ 49	$ 6	$ 2	$ 11
Allowance for credit losses	160	47	39	17	24	9	5	10
Other decommissioning-related activity	(946)	—	—	—	—	—	—	—
Energy-related options	125	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates[(b)]	(171)	(42)	(26)	(12)	(91)	(53)	(14)	(24)
Severance costs	(57)	2	—	—	1	—	—	—
Long-term incentive plan	137	—	—	—	—	—	—	—
Amortization of operating ROU Asset	183	1	—	29	28	6	8	4
AFUDC - Equity	(136)	(34)	(26)	(27)	(49)	(40)	(6)	(3)

(a) Exelon's 2022 and 2021 amounts include amounts related to Generation prior to the separation. See Note 2 — Discontinued Operations for additional information.
(b) For ComEd, reflects the true-up adjustments in Regulatory assets and liabilities associated with its 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 3 — Regulatory Matters for additional information.

(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, 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
Balance at December 31, 2021								
Cash and cash equivalents	$ 672	$ 131	$ 36	$ 51	$ 136	$ 34	$ 28	$ 29
Restricted cash and cash equivalents	321	210	8	4	77	34	43	—
Restricted cash included in Other deferred debits and other assets	44	43	—	—	—	—	—	—
Cash, restricted cash, and cash equivalents included in current assets of discontinued operations	582	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,619	$ 384	$ 44	$ 55	$ 213	$ 68	$ 71	$ 29
Balance at December 31, 2020								
Cash and cash equivalents	$ 432	$ 83	$ 19	$ 144	$ 111	$ 30	$ 15	$ 17
Restricted cash and cash equivalents	349	279	7	1	39	35	—	3
Restricted cash included in Other deferred debits and other assets	53	43	—	—	10	—	—	10
Cash, restricted cash, and cash equivalents included in current assets of discontinued operations	332	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,166	$ 405	$ 26	$ 145	$ 160	$ 65	$ 15	$ 30

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, 2023						
Rabbi trust investments[a]	$ 231	$ —	$ 28	$ 9	$ 142	$ 124
Equity method investments	15	6	7	—	1	—
Other investments	5	—	—	—	—	—
Total investments	$ 251	$ 6	$ 35	$ 9	$ 143	$ 124
Balance at December 31, 2022						
Rabbi trust investments[a]	$ 216	$ —	$ 22	$ 7	$ 138	$ 119
Equity method investments	$ 16	$ 6	$ 8	$ —	$ —	$ —
Total investments	$ 232	$ 6	$ 30	$ 7	$ 138	$ 119

(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, 2023								
Compensation-related accruals[a]	$ 661	$ 206	$ 87	$ 81	$ 107	$ 27	$ 17	$ 12
Taxes accrued	221	204	96	75	137	116	30	10
Interest accrued	414	148	49	44	72	38	13	15
Balance at December 31, 2022								
Compensation-related accruals[a]	$ 613	$ 179	$ 81	$ 79	$ 104	$ 29	$ 20	$ 16
Taxes accrued	211	92	10	34	70	52	8	12
Interest accrued	338	124	47	42	61	32	9	14

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

23. Related Party Transactions (All Registrants)

Utility Registrants' expense with Generation

The Utility Registrants incurred expenses from transactions with the Generation affiliate as described in the footnotes to the table below prior to separation on February 1, 2022. Such expenses were primarily recorded as Purchased power from affiliates and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants:

	At December 31,	
	2022	2021
ComEd[a]	$ 59	$ 376
PECO[b]	33	196
BGE[c]	18	236
PHI	51	366
Pepco[d]	39	270
DPL[e]	10	79
ACE[f]	2	17

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

(a) ComEd had an ICC-approved RFP contract with Generation to provide a portion of ComEd's electric supply requirements. ComEd also purchased RECs and ZECs from Generation.
(b) PECO received electric supply from Generation under contracts executed through PECO's competitive procurement process. In addition, PECO had a ten-year agreement with Generation to sell solar AECs.
(c) BGE received a portion of its energy requirements from Generation under its MDPSC-approved market-based SOS and gas commodity programs.
(d) Pepco received electric supply from Generation under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.
(e) DPL received a portion of its energy requirements from Generation under its MDPSC and DEPSC approved market-based SOS commodity programs.
(f) ACE received electric supply from Generation under contracts executed through ACE's competitive procurement process approved by the NJBPU.

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		
	For the years ended December 31,			For the years ended December 31,		
	2023	2022	2021	2023	2022	2021
Exelon						
BSC				$ 670	$ 707	$ 508
PHISCO				96	80	72
ComEd						
BSC	$ 353	$ 316	$ 304	307	311	207
PECO						
BSC	213	197	169	120	115	81
BGE						
BSC	221	204	189	90	122	92
PHI						
BSC	177	188	168	153	159	128
PHISCO	—	—	—	95	80	72
Pepco						
BSC	114	110	96	59	60	50
PHISCO	122	112	114	39	33	31
DPL						
BSC	73	71	61	43	45	43
PHISCO	98	96	99	29	26	22
ACE						
BSC	59	57	53	47	54	33
PHISCO	92	84	86	26	21	19

Current Receivables from/Payables to affiliates

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

The following tables present current Receivables from affiliates and current Payables to affiliates:

December 31, 2023

	Receivables from affiliates:									
Payables to affiliates:	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
ComEd		$ —	$ —	$ —	$ —	$ —	$ 64	$ —	$ 8	$ 72
PECO	$ —		—	—	—	—	36	—	3	39
BGE	—	—		—	—	—	33	—	2	35
PHI	—	—	—	—	—	—	5	—	10	15
Pepco	—	—	—		—	—	17	14	1	32
DPL	—	1	—	—		—	12	11	1	25
ACE	—	1	—	1	1		11	11	—	25
Other	3	—	—	1	—	3	1	—		8
Total	$ 3	$ 2	$ —	$ 2	$ 1	$ 3	$ 179	$ 36	$ 25	$ 251

December 31, 2022

	Receivables from affiliates:									
Payables to affiliates:	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
ComEd		$ —	$ —	$ —	$ —	$ —	$ 66	$ —	$ 8	$ 74
PECO	$ —		—	—	—	—	39	—	3	42
BGE	—	—		—	—	—	38	—	1	39
PHI	—	—	—	—	—	—	4	—	10	14
Pepco	—	—	—		—	—	20	13	1	34
DPL	—	2	—	—		—	12	8	—	22
ACE	—	2	—	—	—		14	9	1	26
Other	3	—	—	—	—	1	—	—		4
Total	$ 3	$ 4	$ —	$ —	$ —	$ 1	$ 193	$ 30	$ 24	$ 255

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,					
	2023			**2022**		
	Exelon	**ComEd**	**PECO**	**Exelon**	**ComEd**	**PECO**
ComEd Financing III	$ 206	$ 205	$ —	$ 206	$ 205	$ —
PECO Trust III	81	—	81	81	—	81
PECO Trust IV	103	—	103	103	—	103
Total	$ 390	$ 205	$ 184	$ 390	$ 205	$ 184

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 2023, each of the Registrant's management, including its principal executive officer and principal financial officer, evaluated disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in that Registrant’s periodic reports that it files with the SEC. 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, 2023, the principal executive officer and principal financial officer of each of the Registrants concluded that such Registrant’s disclosure controls and procedures were effective to accomplish its objectives.

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 have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2023 that have materially affected, or are reasonably likely to materially affect, any of the Registrant's 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 of December 31, 2023. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2023 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.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not Applicable

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 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 at February 21, 2024.

Directors, Director Nomination Process and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at the annual meeting of shareholders (Item 401 of Regulation S-K), the director nomination process (Item 407(c)(3)), the audit committee (Item 407(d)(4) and (d)(5)), and the beneficial reporting compliance (Sec. 16(a)) is incorporated herein by reference to information to be contained in Exelon's definitive 2024 proxy statement (2024 Exelon Proxy Statement) and the ComEd information statement (2024 ComEd Information Statement) to be filed with the SEC on or before April 29, 2024 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 Exelon's and ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. 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.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under Executive Compensation Data and Compensation Committee Report in the Exelon Proxy Statement for the 2024 Annual Meeting of Shareholders or the ComEd 2024 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 2024 Exelon Proxy Statement or the ComEd 2024 Information Statement, which are incorporated herein by reference.

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	3,524,772	$ —	41,706,088

(1) Balance includes unvested performance shares, and unvested restricted stock units that were granted under the Exelon LTIP or predecessor company plans (including shares awarded under those plans and deferred into the stock deferral plan) and deferred stock units granted to directors as part of their compensation. Unvested performance shares are subject to performance metrics and to a total shareholder return modifier. Additionally, pursuant to the terms of the Exelon LTIP plan, 50% of final payouts are made in the form of shares of common stock and 50% is made in form of in cash, or if the participant has exceeded 200% of their stock ownership requirement, 100% of the final payout is made in cash. For performance shares granted in 2021, 2022, and 2023, the total includes the maximum number of shares that could be issued assuming all participants receive 50% of payouts in shares and assuming the performance and total shareholder return modifier metrics were both at maximum, representing best case performance, for a total of 2,401,852 shares. If the performance and total shareholder return modifier metrics were at "target", the number of securities to be issued for such awards would be 1,200,926. The balance also includes 410,234 shares to be issued upon the conversion of deferred stock units awarded to members of the Exelon board of directors. Conversion of the deferred stock units to shares of common stock occurs after a director terminates service to the Exelon board or the board of any of its subsidiary companies. See Note 20 — Stock-Based Compensation Plans of the Combined Notes to Consolidated Financial Statements for additional information about the material features of the plans.

(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 11,475,245 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 Related Person Transactions and Director Independence in the Exelon Proxy Statement for the 2024 Annual Meeting of Shareholders or the ComEd 2024 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 Ratification of PricewaterhouseCoopers LLP as Exelon's Independent Accountant for 2024 in the Exelon Proxy Statement for the 2024 Annual Meeting of Shareholders and the ComEd 2024 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 13, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022, and 2021

Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022, and 2021

Consolidated Balance Sheets at December 31, 2023 and 2022

Consolidated Statements of Changes in Equity for the Years Ended December 31, 2023, 2022, and 2021

Notes to Consolidated Financial Statements

(ii) Financial Statement Schedules:

Schedule I—Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2023 and 2022 and for the Years Ended December 31, 2023, 2022, and 2021

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021

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)	2023	2022	2021
Operating expenses			
Operating and maintenance	$ 88	$ 25	$ (9)
Operating and maintenance from affiliates	7	4	14
Other	1	2	2
Total operating expenses	96	31	7
Operating loss	(96)	(31)	(7)
Other income and (deductions)			
Interest expense, net	(544)	(413)	(333)
Equity in earnings of investments	2,728	2,450	1,908
Interest income from affiliates, net	9	5	—
Other, net	19	22	—
Total other income and (deductions)	2,212	2,064	1,575
Income from continuing operations before income taxes	2,116	2,033	1,568
Income taxes	(212)	(21)	(48)
Net income from continuing operations after income taxes	2,328	2,054	1,616
Net income from discontinued operations after income taxes	—	116	90
Net income	$ 2,328	$ 2,170	$ 1,706
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefits reclassified to periodic benefit cost	—	(1)	(4)
Actuarial losses reclassified to periodic benefit cost	26	42	223
Pension and non-pension postretirement benefit plans valuation adjustments	(109)	46	431
Unrealized (loss) gain on cash flow hedges	(5)	2	—
Other comprehensive (loss) income	(88)	89	650
Comprehensive income	$ 2,240	$ 2,259	$ 2,356

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

(In millions)	For the Years Ended December 31, 2023	2022	2021
Net cash flows provided by operating activities	$ 1,486	$ 1,690	$ 3,629
Cash flows from investing activities			
Changes in Exelon intercompany money pool	(43)	35	381
Notes receivable from affiliates	—	274	—
Investment in affiliates	(1,864)	(4,011)	(2,231)
Other investing activities	(1)	—	1
Net cash flows used in investing activities	(1,908)	(3,702)	(1,849)
Cash flows from financing activities			
Changes in short-term borrowings	78	448	—
Proceeds from short-term borrowings with maturities greater than 90 days	—	1,150	500
Repayments on short-term borrowings with maturities greater than 90 days	—	(1,300)	(350)
Issuance of long-term debt	2,500	3,350	—
Retirement of long-term debt	(850)	(1,150)	(300)
Issuance of common stock	140	563	—
Dividends paid on common stock	(1,433)	(1,334)	(1,497)
Proceeds from employee stock plans	41	36	80
Other financing activities	(39)	(35)	19
Net cash flows provided by (used in) financing activities	437	1,728	(1,548)
Increase (decrease) in cash, restricted cash, and cash equivalents	15	(284)	232
Cash, restricted cash, and cash equivalents at beginning of period	11	295	63
Cash, restricted cash, and cash equivalents at end of period	$ 26	$ 11	$ 295

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2023	December 31, 2022
ASSETS		
Current assets		
Cash and cash equivalents	$ 26	$ 11
Accounts receivable, net		
Other accounts receivable	561	358
Accounts receivable from affiliates	14	17
Notes receivable from affiliates	225	182
Regulatory assets	188	154
Other	17	6
Total current assets	1,031	728
Property, plant, and equipment, net	44	44
Deferred debits and other assets		
Regulatory assets	2,877	2,650
Investments in affiliates from continuing operations	38,545	35,925
Deferred income taxes	884	929
Non-pension postretirement benefit asset	144	187
Other	107	115
Total deferred debits and other assets	42,557	39,806
Total assets	$ 43,632	$ 40,578

See the Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2023	2022
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 1,026	$ 948
Long-term debt due within one year	500	850
Accounts payable	194	188
Accrued expenses	144	101
Payables to affiliates	361	360
Regulatory liabilities	10	12
Pension obligations	45	77
Other	49	7
Total current liabilities	2,329	2,543
Long-term debt	10,713	8,742
Deferred credits and other liabilities		
Regulatory liabilities	92	103
Pension obligations	4,268	3,896
Deferred income taxes	56	53
Other	419	497
Total deferred credits and other liabilities	4,835	4,549
Total liabilities	17,877	15,834
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 999 shares and 994 shares outstanding as of December 31, 2023 and 2022, respectively)	21,114	20,908
Treasury stock, at cost (2 shares as of December 31, 2023 and 2022)	(123)	(123)
Retained earnings	5,490	4,597
Accumulated other comprehensive loss, net	(726)	(638)
Total shareholders' equity	25,755	24,744
Total liabilities and shareholders' equity	$ 43,632	$ 40,578

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, 2023 and 2022, 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%. As of February 1, 2022, as a result of the completion of the separation, Exelon Corporate no longer retains any equity ownership interest in Generation or Constellation. The separation of Constellation, including Generation and its subsidiaries, met the criteria for discontinued operations and as such, results of operations are presented as discontinued operations and have been excluded from continuing operations for all periods presented. Accounting rules require certain BSC costs previously allocated to Generation to be presented as part of Exelon's continuing operations as these costs do not qualify as expenses of the discontinued operations. Comprehensive income and cash flows related to Generation have not been segregated and are included in the Condensed Statements of Operations and Comprehensive Income and Condensed Statements of Cash Flows, respectively, for all periods presented. See Note 2 — Discontinued Operations of the Combined Notes to Consolidated Financial Statements for additional information.

2. Retirement Benefits

See Note 14—Retirement Benefits of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's retirement benefits.

3. Derivative Financial Instruments

See Note 15—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 $527 million in outstanding commercial paper borrowings as of December 31, 2023 and $449 million outstanding commercial paper as of December 31, 2022.

Revolving Credit Agreements

As of December 31, 2023, Exelon Corporation had a $900 million aggregate bank commitment under its existing syndicated revolving facility in which $370 million was available to support additional commercial paper as of December 31, 2023. See Note 16 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon Corporate's credit agreement.

On February 1, 2022, Exelon Corporate entered into a new 5-year revolving credit facility with an aggregate bank commitment of $900 million at a variable interest rate of SOFR plus 1.275% which replaced its existing $600 million syndicated revolving credit facility.

Exelon Corporate had no outstanding amounts on the revolving credit facilities as of December 31, 2023.

Short-Term Loan Agreements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

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 2023 and was bifurcated into two tranches of $300 million on March 14, 2023 and $200 million on March 24, 2023. The agreements will expire on March 14, 2024 and March 22, 2024, respectively. Pursuant to the loan agreements, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.90% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

Long-Term Debt

The following tables present the outstanding long-term debt for Exelon Corporate at December 31, 2023 and December 31, 2022:

	Rates		Maturity Date	December 31, 2023	December 31, 2022
Long-term debt					
Senior unsecured notes[(a)]	2.75 % -	7.60 %	2025 - 2053	$ 10,639	$ 8,139
Loan agreement[(c)]		6.23 %	2024	500	1,350
Total long-term debt				11,139	9,489
Unamortized debt discount and premium, net				(13)	(10)
Unamortized debt issuance costs				(65)	(51)
Fair value adjustment				152	164
Long-term debt due within one year[(b)]				(500)	(850)
Long-term debt				$ 10,713	$ 8,742

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(a) Senior unsecured notes included mirror debt that was held on Exelon Corporation's Balance Sheet in 2021. In connection with the separation, on January 31, 2022, Exelon Corporate received cash from Generation of $258 million to settle the intercompany loan. See Note 16 — Debt and Credit Agreements for additional information on the merger debt.
(b) In connection with the separation, Exelon Corporate entered into three 18-month term loan agreements. On January 21, 2022, two of the loan agreements were issued for $300 million each with an expiration date of July 21, 2023. On January 24, 2022, the third loan agreement was issued for $250 million with an expiration date of July 24, 2023. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.65%.
(c) Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to SOFR plus 0.85%.

The long-term debt maturities for Exelon Corporate for the periods 2024 through 2028 and thereafter are as follows:

2024	$ 500
2025	807
2026	750
2027	650
2028	1,000
Thereafter	7,432
Total long-term debt	$ 11,139

5. Commitments and Contingencies

See Note 18—Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies.

6. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

(In millions)	For the Years Ended December 31, 2023	2022	2021
Operating and maintenance from affiliates:			
BSC[(a)]	$ 7	$ 4	$ 14
Total operating and maintenance from affiliates:	$ 7	$ 4	$ 14
Interest income (expense) from affiliates, net:			
BSC	$ 6	$ 4	$ —
EEDC[(b)]	3	1	—
Total interest income from affiliates, net:	$ 9	$ 5	$ —
Equity in earnings (losses) of investments:			
BSC	$ —	$ (18)	$ (301)
EEDC[(b)]	2,727	2,482	2,215
PCI	2	(9)	(1)
Exelon Enterprises	1	—	—
Exelon InQB8R	(2)	(4)	(7)
Other	—	(1)	2
Total equity in earnings of investments:	$ 2,728	$ 2,450	$ 1,908
Cash contributions received from affiliates	$ 1,978	$ 2,027	$ 1,842

(in millions)	At December 31, 2023	2022
Accounts receivable from affiliates (current):		
BSC	$ —	$ 3
ComEd	4	4
PECO	2	2
BGE	1	1
PHISCO	7	7
Total accounts receivable from affiliates (current):	$ 14	$ 17
Notes receivable from affiliates (current):		
BSC[(a)]	$ 160	$ 138
PHI	65	44
Total notes receivable from affiliates (current):	$ 225	$ 182
Investments in affiliates from continuing operations:		
BSC[(a)]	$ 384	$ 384
EEDC[(b)]	37,705	35,092
PCI	54	52
UII	365	365
Voluntary Employee Beneficiary Association trust	9	4
Exelon Enterprises	4	3
Conectiv	12	12
Exelon InQB8R	13	15
Other[(c)]	(1)	(2)
Total investments in affiliates from continuing operations:	$ 38,545	$ 35,925
Accounts payable to affiliates (current):		
UII	$ 360	$ 360
BSC[(a)]	1	—
Total accounts payable to affiliates (current):	$ 361	$ 360

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

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(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.
(c) Primarily relates to elimination of affiliate transactions with Generation, primarily related to the Regulatory Agreement Units. See Note 3 — Regulatory Matters and Note 23 — Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

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, 2023					
Allowance for credit losses[a]	$ 409	$ 171 [b]	$ 20	$ 201 [c]	$ 399
Deferred tax valuation allowance	94	—	20	—	114
For the year ended December 31, 2022					
Allowance for credit losses[a]	$ 392	$ 174 [b]	$ 28	$ 185 [c]	$ 409
Deferred tax valuation allowance	37	—	57	—	94
For the year ended December 31, 2021					
Allowance for credit losses[a]	$ 405	$ 107 [b]	$ —	$ 120 [c]	$ 392
Deferred tax valuation allowance	4	—	33 [d]	—	37

(a) Excludes the noncurrent Allowance for credit losses related to PECO's installment plan receivables of $6 million, $7 million, and $14 million for the years ended December 31, 2023, 2022, and 2021, 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.
(d) DPL recorded a full valuation allowance against Delaware net operating losses carryforwards due to a change in Delaware tax law. See Note 13 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the valuation allowance.

Commonwealth Edison Company and Subsidiary Companies

(2) ComEd

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Balance Sheets at December 31, 2023 and 2022
	Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2023, 2022, and 2021
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021
	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, 2023					
Allowance for credit losses	$ 76	$ 45 (a)	$ 13	$ 48 (b)	$ 86
For the year ended December 31, 2022					
Allowance for credit losses	$ 90	$ 24 (a)	$ 8	$ 46 (b)	$ 76
For the year ended December 31, 2021					
Allowance for credit losses	$ 118	$ 18 (a)	$ 1	$ 47 (b)	$ 90

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(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 3 – 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 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Balance Sheets at December 31, 2023 and 2022
	Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2023, 2022, and 2021
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021
	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, 2023					
Allowance for credit losses[a]	$ 114	$ 43 [b]	$ 9	$ 63 [c]	$ 103
Deferred tax valuation allowance	7	—	—	—	7
For the year ended December 31, 2022					
Allowance for credit losses[a]	$ 112	$ 44 [b]	$ 14	$ 56 [c]	$ 114
Deferred tax valuation allowance	3	—	4	—	7
For the year ended December 31, 2021					
Allowance for credit losses[a]	$ 124	$ 32 [b]	$ (6)	$ 38 [c]	$ 112
Deferred tax valuation allowance	1	—	2	—	3

(a) Excludes the noncurrent Allowance for credit losses related to PECO's installment plan receivables of $6 million, $7 million, and $14 million for the years ended December 31, 2023, 2022, and 2021, respectively.
(b) The amount charged to costs and expenses includes the amount that was reclassified to the COVID-19 regulatory asset. See Note 3 – 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 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)

Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022 and 2021

Statements of Cash Flows for the Years Ended December 31, 2023, 2022 and 2021

Balance Sheets at December 31, 2023 and 2022

Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2023, 2022 and 2021

Notes to Financial Statements

(ii) Financial Statement Schedule:

Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021

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, 2023					
Allowance for credit losses	$ 64	$ 26 [(a)]	$ 5	$ 42 [(b)]	$ 53
Deferred tax valuation allowance	3	—	—	—	3
For the year ended December 31, 2022					
Allowance for credit losses	$ 47	$ 37 [(a)]	$ 6	$ 26 [(b)]	$ 64
Deferred tax valuation allowance	—	—	3	—	3
For the year ended December 31, 2021					
Allowance for credit losses	$ 44	$ 16 [(a)]	$ 3	$ 16 [(b)]	$ 47
Deferred tax valuation allowance	—	—	—	—	—

(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 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Balance Sheets at December 31, 2023 and 2022
	Consolidated Statements of Changes in Equity for the Years Ended December 31, 2023, 2022, and 2021
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021
	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, 2023					
Allowance for credit losses	$ 155	$ 57 (a)	$ (7)	$ 48 (b)	$ 157
Deferred tax valuation allowance	35	—	—	—	35
For the year ended December 31, 2022					
Allowance for credit losses	$ 143	$ 69 (a)	$ —	$ 57 (b)	$ 155
Deferred tax valuation allowance	31	—	4	—	35
For the year ended December 31, 2021					
Allowance for credit losses	$ 119	$ 41 (a)	$ 2	$ 19 (b)	$ 143
Deferred tax valuation allowance	—	—	31 (c)	—	31

(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.
(c) DPL recorded a full valuation allowance against Delaware net operating losses carryforwards due to a change in Delaware tax law. See Note 13 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the valuation allowance.

Potomac Electric Power Company

(6) Pepco

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022 and 2021
	Statements of Cash Flows for the Years Ended December 31, 2023, 2022 and 2021
	Balance Sheets at December 31, 2023 and 2022
	Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2023, 2022 and 2021
	Notes to Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021
	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, 2023					
Allowance for credit losses	$ 72	$ 31 [(a)]	$ (5)	$ 18 [(b)]	$ 80
For the year ended December 31, 2022					
Allowance for credit losses	$ 53	$ 36 [(a)]	$ 4	$ 21 [(b)]	$ 72
For the year ended December 31, 2021					
Allowance for credit losses	$ 45	$ 14 [(a)]	$ 2	$ 8 [(b)]	$ 53

(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 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022 and 2021
	Statements of Cash Flows for the Years Ended December 31, 2023, 2022 and 2021
	Balance Sheets at December 31, 2023 and 2022
	Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2023, 2022 and 2021
	Notes to Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021
	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, 2023					
Allowance for credit losses	$ 28	$ 10 (a)	$ —	$ 11 (b)	$ 27
Deferred tax valuation allowance	32	—	—	—	32
For the year ended December 31, 2022					
Allowance for credit losses	$ 26	$ 13 (a)	$ (2)	$ 9 (b)	$ 28
Deferred tax valuation allowance	31	—	1	—	32
For the year ended December 31, 2021					
Allowance for credit losses	$ 31	$ 6 (a)	$ (1)	$ 10 (b)	$ 26
Deferred tax valuation allowance	—	—	31 (c)	—	31

(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.
(c) DPL recorded a full valuation allowance against Delaware net operating losses carryforwards due to a change in Delaware tax law. See Note 13 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the valuation allowance.

Atlantic City Electric Company and Subsidiary Company

(8) ACE

(i)	Financial Statements (Item 8):
	Report of Independent Registered Public Accounting Firm dated February 21, 2024 of PricewaterhouseCoopers LLP (PCAOB ID 238)
	Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022, and 2021
	Consolidated Balance Sheets at December 31, 2023 and 2022
	Consolidated Statements of Changes in Shareholder's Equity for the Years Ended December 31, 2023, 2022, and 2021
	Notes to Consolidated Financial Statements
(ii)	Financial Statement Schedule:
	Schedule II—Valuation and Qualifying Accounts for the Years Ended December 31, 2023, 2022, and 2021
	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, 2023					
Allowance for credit losses	$ 55	$ 16 [(a)]	$ (2)	$ 19 [(b)]	$ 50
For the year ended December 31, 2022					
Allowance for credit losses	$ 64	$ 20 [(a)]	$ (2)	$ 27 [(b)]	$ 55
For the year ended December 31, 2021					
Allowance for credit losses	$ 43	$ 21 [(a)]	$ 1	$ 1 [(b)]	$ 64

(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 3 – 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 July 24, 2018	File No. 001-16169, Form 8-K dated July 27, 2018, Exhibit 3.1
3-2	Amended and Restated Bylaws of Exelon Corporation, as amended on August 3, 2022	File No. 001-16169, Form 10-Q dated August 3, 2022, Exhibit 3.1

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. 333-206474, Registration Statement on Form S-3 dated August 19, 2015
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	First Supplemental 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 4.2
4-4-2	Second Supplemental Indenture, dated April 3, 2017, between Exelon and The Bank of New York Mellon Trust Company, N.A., as trustee, to that certain Indenture (For Unsecured Subordinated Debt Securities), dated June 17, 2014	File No. 001-16169, Form 8-K dated April 4, 2017, Exhibit 4.3
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

Exhibit No.	Description	Location
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
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
4-6	Description of Exelon Securities	File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.63

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	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
4-14	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)]
4-14-1	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
4-14-2	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

Exhibit No.	Description	Location
4-14-3	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
4-14-4	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
4-14-5	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
4-14-6	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
4-14-7	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
4-14-8	Supplemental Indenture to Commonwealth Edison Company Mortgage dated as of October 28, 2014	File No. 001-01839, Form 8-K dated November 10, 2014, Exhibit 4.1
4-14-9	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
4-14-10	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
4-14-11	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
4-14-12	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
4-14-13	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
4-14-14	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
4-14-15	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
4-14-16	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
4-14-17	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
4-14-18	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
4-14-19	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
4-14-20	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
4-14-21	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
4-15	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
4-16	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
4-17	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
4-18	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)]
4-18-1	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)]
4-18-2	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
4-18-3	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
4-18-4	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

Exhibit No.	Description	Location
4-18-5	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 1, 2012	File No. 000-16844, Form 8-K dated September 17, 2012, Exhibit 4.1
4-18-6	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
4-18-7	Supplemental Indenture to PECO Energy Company's First and Refunding Mortgage dated as of September 15, 2015	File No. 000-16844, Form 8-K dated October 5, 2015, Exhibit 4.1
4-18-8	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
4-18-9	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
4-18-10	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
4-18-11	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
4-18-12	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
4-18-13	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
4-18-14	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
4-18-15	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
4-18-16	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
4-18-17	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
4-19	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

Exhibit No.	Description	Location
4-20	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
4-21	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
4-22	Description of PECO Securities	File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 4.64

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 March 29, 2011	File No. 001-03559, Form 8-K dated April 1, 2011, Exhibit 4.2
4-23-6	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of August 18, 2014	File No. 001-03559, Form 8-K dated August 19, 2014, Exhibit 4.2
4-23-7	Supplemental Indenture to Atlantic City Electric Company Mortgage dated as of December 1, 2015	File No. 001-03559, Form 8-K dated December 2, 2015, Exhibit 4.2 (included as Exhibit A to Exhibit 1.1).
4-23-8	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
4-23-9	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
4-23-10	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
4-23-11	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
4-23-12	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
4-23-13	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
4-23-14	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
4-24	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 June 2, 2014	File No. 001-01405, Form 8-K dated June 3, 2014, Exhibit 4.3
4-25-4	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
4-25-5	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
4-25-6	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
4-25-7	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
4-25-8	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
4-25-9	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
4-25-10	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
4-25-11	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

Exhibit No.	Description	Location
4-25-12	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
4-25-13	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
4-26	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
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 11, 2014	File No. 001-01072, Form 8-K dated March 12, 2014, Exhibit 4.2

Exhibit No.	Description	Location
4-27-10	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
4-27-11	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
4-27-12	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
4-27-13	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
4-27-14	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
4-27-15	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
4-27-16	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
4-27-17	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
4-28	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
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	Credit Agreement for $900,000,000 dated February 1, 2022, between Exelon Corporation and various financial institutions	File No. 001-16169, Form 10-K dated February 25, 2022, Exhibit 10.40

Exhibit No.	Description	Location
10-5	Exelon Corporation Non-Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective April 28, 2020)	File No. 001-16169, Form 10-Q dated August 4, 2020, Exhibit 10.1
10-6	Form of Exelon Corporation Unfunded Deferred Compensation Plan for Directors (as amended and restated Effective March 12, 2012) *	File No. 001-16169, Form 10-K dated February 13, 2015, Exhibit 10.3
10-7	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
10-8	Exelon Corporation Annual Incentive Plan for Senior Executives (As Amended Effective January 1, 2014) *	File No. 001-16169, Proxy Statement dated April 1, 2014, Appendix A
10-9	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
10-10	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
10-11	Exelon Corporation 2020 Long-Term Incentive Plan (Effective April 28, 2020)	File No. 001-16169, Proxy Statement dated March 18, 2020, Appendix A
10-12	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
10-13	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
10-14	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
10-15	Exelon Corporation Senior Management Severance Plan	File No. 001-16169, Form 10-K dated February 11, 2020, Exhibit 10.13
10-15-1	Exelon Corporation Senior Management Severance Plan as Amended and Restated effective February 1, 2024	Filed herewith.
10-16	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
10-17	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
10-17-1	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
10-18	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005)	File No. 001-16169, Form 10-K dated February 13, 2007, Exhibit 10.56
10-19	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
10-20	Form of Exelon Corporation Change in Control Agreement	File No. 001-16169, Form 10-Q dated October 26, 2016, Exhibit 10.1
10-21	Letter Agreement, dated June 4, 2020, between Exelon Corporation and William A. Von Hoene, Jr.	File No. 001-16169, Form 10-K dated February 24, 2021, Exhibit 10.74
10-22	2023 Amendment to Certain Plans of Exelon Corporation	Filed herewith.

Commonwealth Edison Company

Exhibit No.	Description	Location
10-23	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
10-24	Credit Agreement for $1,000,000,000 dated February 1, 2022, between Commonwealth Edison Company and various financial institutions	File No. 001-01839, Form 10-K dated February 25, 2022, Exhibit 10.42

Baltimore Gas and Electric Company

Exhibit No.	Description	Location
10-25	Credit Agreement for $600,000,000 dated February 1, 2022, between Baltimore Gas and Electric Company and various financial institutions	File No. 001-01910, Form 10-K dated February 25, 2022, Exhibit 10.41

PECO Energy Company

Exhibit No.	Description	Location
10-26	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
10-27	Credit Agreement for $600,000,000 dated February 1, 2022, between PECO Energy Company and various financial institutions	File No. 000-16844, Form 10-K dated February 25, 2022, Exhibit 10.43

Atlantic City Electric Company, Potomac Electric Power Company, Delmarva Power & Light Company

Exhibit No.	Description	Location
10-28	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
10-29	Credit Agreement for $900,000,000 dated February 1, 2022, 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 February 25, 2022, Exhibit 10.44

(14) Code of Ethics

Exelon Corporation

Exhibit No.	Description	Location
14-1	Exelon Code of Conduct, as amended December 05, 2023	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	Filed herewith.

Exhibit No.	Description
	Subsidiaries
21-1	Exelon Corporation
21-2	Commonwealth Edison Company
21-3	PECO Energy Company
21-4	Baltimore Gas and Electric Company

Exhibit No.	Description
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	Potomac Electric Power Company
	Power of Attorney (Exelon Corporation)
24-1	Anthony K. Anderson
24-2	Anna Richo
24-3	Calvin G. Butler, Jr.
24-4	W. Paul Bowers
24-5	Marjorie Rodgers Cheshire
24-6	Matthew Rogers
24-7	Linda P. Jojo
24-8	Charisse R. Lillie
24-9	John F. Young
24-10	Brian Segedi
	Power of Attorney (Commonwealth Edison Company)
24-11	Calvin G. Butler, Jr.
24-12	Ricardo Estrada
24-13	Zaldwaynaka Scott
24-14	Smita Shah
24-15	Gil C. Quiniones
	Power of Attorney (PECO Energy Company)
24-16	Nicholas Bertram
24-17	Calvin G. Butler, Jr.
24-18	John S. Grady
24-19	Michael A. Innocenzo
24-20	Sharmaine Matlock-Turner
24-21	Michael Nutter
24-22	Michelle Hong
	Power of Attorney (Baltimore Gas and Electric Company)

Exhibit No.	Description
24-23	Calvin G. Butler, Jr.
24-24	James R. Curtiss
24-25	Carim V. Khouzami
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	Calvin G. Butler, Jr.
24-35	Debra P. DiLorenzo
24-36	Benjamin Wu
24-37	Linda W. Cropp
24-38	Gayle Littleton
	Power of Attorney (Potomac Electric Power Company)
24-39	J. Tyler Anthony
24-40	Phillip S. Barnett
24-41	Calvin G. Butler, Jr.
24-42	Rodney Oddoye
24-43	Valencia McClure
24-44	Tamla Olivier
24-45	Anne Bancroft
	Power of Attorney (Delmarva Power & Light Company)
24-46	J. Tyler Anthony
24-47	Calvin G. Butler, Jr.
	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, 2023 filed by the following officers for the following registrants:

Exhibit No.	Description
31-1	Filed by Calvin G. Butler, Jr. for Exelon Corporation

Exhibit No.	Description
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 Michael A. Innocenzo for PECO Energy Company
31-6	Filed by Marissa Humphrey for PECO Energy Company
31-7	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-8	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
31-10	Filed by Phillip S. Barnett for Pepco Holdings LLC
31-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
31-12	Filed by Phillip S. Barnett for Potomac Electric Power Company
31-13	Filed by J. Tyler Anthony for Delmarva Power & Light Company
31-14	Filed by Phillip S. Barnett for Delmarva Power & Light Company
31-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
31-16	Filed by Phillip S. Barnett 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, 2023 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 Michael A. Innocenzo for PECO Energy Company
32-6	Filed by Marissa Humphrey for PECO Energy Company
32-7	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
32-8	Filed by David M. Vahos for Baltimore Gas and Electric Company
32-9	Filed by J. Tyler Anthony for Pepco Holdings LLC
32-10	Filed by Phillip S. Barnett for Pepco Holdings LLC
32-11	Filed by J. Tyler Anthony for Potomac Electric Power Company
32-12	Filed by Phillip S. Barnett for Potomac Electric Power Company
32-13	Filed by J.Tyler Anthony for Delmarva Power & Light Company
32-14	Filed by Phillip S. Barnett for Delmarva Power & Light Company
32-15	Filed by J. Tyler Anthony for Atlantic City Electric Company
32-16	Filed by Phillip S. Barnett for Atlantic City Electric Company

Exhibit No.	Description
101.INS	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
101.SCH	Inline XBRL Taxonomy Extension Schema Document.
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	Inline XBRL Taxonomy Extension 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)

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* 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

Registrants may voluntarily include a summary of information required by Form 10-K under this Item 16. The Registrants have elected not to include such summary information.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 21st day of February, 2024.

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 21st day of February, 2024.

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 and Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT A. KLECZYNSKI Robert A. Kleczynski	Senior Vice President, Corporate Controller and Tax (Principal Accounting Officer)

This annual report has also been signed below by Gayle E. Littleton, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Anthony K. Anderson
Anna Richo
W. Paul Bowers
Marjorie Rodgers Cheshire
Matthew Rogers
Linda P. Jojo
Charisse R. Lillie
John F. Young
Bryan Segedi

By:	/s/ GAYLE E. LITTLETON	February 21, 2024
Name:	Gayle E. Littleton	

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 21st day of February, 2024.

COMMONWEALTH EDISON COMPANY

By:	/s/ GIL C. QUINIONES
Name:	Gil C. Quiniones
Title:	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 21st day of February, 2024.

Signature	Title
/s/ GIL C. QUINIONES Gil C. Quiniones	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/ STEVEN J. CICHOCKI Steven J. Cichocki	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:

Calvin G. Butler, Jr.	**Zaldwaynaka Scott**
Ricardo Estrada	**Smita Shah**

By:	/s/ GIL C. QUINIONES	February 21, 2024
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 21st day of February, 2024.

PECO ENERGY COMPANY

By:	/s/ MICHAEL A. INNOCENZO
Name:	Michael A. Innocenzo
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 21st day of February, 2024.

Signature	**Title**
/s/ MICHAEL A. INNOCENZO Michael A. Innocenzo	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ MARISSA HUMPHREY Marissa Humphrey	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ CAROLINE FULGINITI Caroline Fulginiti	Director, Accounting (Principal Accounting Officer)

This annual report has also been signed below by Michael A. Innocenzo, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Nicholas Bertram	**Sharmain Matlock-Turner**
Calvin G. Butler, Jr.	**Michael Nutter**
John S. Grady	**Michelle Hong**

By:	/s/ MICHAEL A. INNOCENZO	February 21, 2024
Name:	Michael A. Innocenzo	

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 21st day of February, 2024.

BALTIMORE GAS AND ELECTRIC COMPANY

By:	/s/ CARIM V. KHOUZAMI
Name:	Carim V. Khouzami
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 21st day of February, 2024.

Signature	Title
/s/ CARIM V. KHOUZAMI Carim V. Khouzami	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ DAVID M. VAHOS David M. Vahos	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 Carim V. Khouzami, Attorney-in-Fact, on behalf of the following Directors on the date indicated:

Calvin G. Butler, Jr.	**Byron Marchant**
James R. Curtiss	**Tim Regan**
Keith Lee	**Amy Seto**
Rachel Garbow Monroe	**Maria Harris Tildon**

By:	/s/ CARIM V. KHOUZAMI	February 21, 2024
Name:	Carim V. Khouzami	

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 21st day of February, 2024.

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 21st day of February, 2024.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ PHILLIP S. BARNETT Phillip S. Barnett	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JULIE E. GIESE Julie E. Giese	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**
Calvin G. Butler Jr.	**Linda W. Cropp**
Debra P. DiLorenzo	**Gayle Littleton**

By:	/s/ J. TYLER ANTHONY	February 21, 2024
Name:	J. Tyler Anthony	

Table of Contents

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 21st day of February, 2024.

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 21st day of February, 2024.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ PHILLIP S. BARNETT Phillip S. Barnett	Senior Vice President, Chief Financial Officer, Treasurer (Principal Financial Officer) and Director
/s/ JULIE E. GIESE Julie E. Giese	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:

Calvin G. Butler, Jr.
Rodney Oddoye
Valencia McClure
Tamla Olivier
Anne Bancroft

By: /s/ J. TYLER ANTHONY February 21, 2024
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 21st day of February, 2024.

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 21st day of February, 2024.

Signature	Title
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ PHILLIP S. BARNETT Phillip S. Barnett	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JULIE E. GIESE Julie E. Giese	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:

Calvin G. Butler, Jr.

By:	/s/ J. TYLER ANTHONY	February 21, 2024
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 21st day of February, 2024.

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 21st day of February, 2024.

Signature	**Title**
/s/ J. TYLER ANTHONY J. Tyler Anthony	President, Chief Executive Officer (Principal Executive Officer) and Director
/s/ PHILLIP S. BARNETT Phillip S. Barnett	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JULIE E. GIESE Julie E. Giese	Director, Accounting (Principal Accounting Officer)