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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2021
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
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
001-01839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street 49th Floor 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

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

The number of shares outstanding of each registrant's common stock as of September 30, 2021 was:

Exelon Corporation Common Stock, without par value	978,317,787
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,383
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL, and ACE, collectively
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Antelope Valley	Antelope Valley Solar Ranch One
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
EGR IV	ExGen Renewables IV, LLC
EGRP	ExGen Renewables Partners, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
FitzPatrick	James A. FitzPatrick nuclear generating station
NER	NewEnergy Receivables LLC
PCI	Potomac Capital Investment Corporation and its subsidiaries
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Note - of the 2020 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2020 Annual Report on Form 10-K
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income (Loss)
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
BGS	Basic Generation Service
CAISO	California Independent System Operator
CBA	Collective Bargaining Agreement
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Energy Law	Illinois Public Act 102-0662 signed into law on September 15, 2021
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CMC	Carbon Mitigation Credit
CODM	Chief Operating Decision Maker(s)
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	Public Service Commission of the District of Columbia
DOE	United States Department of Energy
DOEE	District of Columbia Department of Energy & Environment
DOJ	United States Department of Justice
DPP	Deferred Purchase Price
DPSC	Delaware Public Service Commission
EDF	Electricite de France SA and its subsidiaries
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
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FRR	Fixed Resource Requirement
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
ISO	Independent System Operator
ISO-NE	Independent System Operator New England Inc.
LIBOR	London Interbank Offered Rate
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
MOPR	Minimum Offer Price Rule
MPSC	Missouri Public Service Commission
MW	Megawatt
MWh	Megawatt hour
NAV	Net Asset Value
N/A	Not applicable
NDT	Nuclear Decommissioning Trust
NERC	North American Electric Reliability Corporation
NGX	Natural Gas Exchange
NJBPU	New Jersey Board of Public Utilities
Non-Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPNS	Normal Purchase Normal Sale scope exception
NPS	National Park Service
NRC	Nuclear Regulatory Commission
NYISO	New York Independent System Operator Inc.
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PG&E	Pacific Gas and Electric Company
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSDAR	Post-Shutdown Decommissioning Activities Report
PSEG	Public Service Enterprise Group Incorporated
PUCT	Public Utility Commission of Texas
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RFP	Request for Proposal

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

Rider	Reconcilable Surcharge Recovery Mechanism
RMC	Risk Management Committee
ROE	Return on Equity
RPS	Renewable Energy Portfolio Standards
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
STRIDE	Maryland Strategic Infrastructure Development and Enhancement Program
TCJA	Tax Cuts and Jobs Act
Transition Bonds	Transition Bonds issued by ACE Funding
UGSOA	United Government Security Officers of America
U.S. Court of Appeals for the D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit or Zero Emission Certificate
ZES	Zero Emission Standard

FILING FORMAT

This combined Form 10-Q is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, 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 the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties including, among others, those related to the timing, manner, tax-free nature, and expected benefits associated with the potential separation of Exelon’s competitive power generation and customer-facing energy business from its six regulated electric and gas utilities. Words such as “could,” “may,” “expects,” “anticipates,” “will,” “targets,” “goals,” “projects,” “intends,” “plans,” “believes,” “seeks,” “estimates,” “predicts,” and variations on such words, and similar expressions that reflect our current views with respect to future events and operational, economic, and financial performance, are intended to identify such forward-looking statements.

The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) the Registrants' combined 2020 Annual Report on Form 10-K in (a) Part I, ITEM 1A. Risk Factors, (b) Part II, ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part II, ITEM 8. Financial Statements and Supplementary Data: Note 19, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, ITEM 1A. Risk Factors, (b) Part I, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and (c) Part I, ITEM 1. Financial Statements: Note 15, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants.

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 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. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	2021	2020	2021	2020
Operating revenues				
Competitive businesses revenues	$ 4,084	$ 4,331	$ 13,250	$ 12,348
Rate-regulated utility revenues	4,873	4,533	13,336	12,643
Revenues from alternative revenue programs	(47)	(11)	129	(66)
Total operating revenues	8,910	8,853	26,715	24,925
Operating expenses				
Competitive businesses purchased power and fuel	1,541	2,311	8,103	6,967
Rate-regulated utility purchased power and fuel	1,492	1,303	3,914	3,439
Operating and maintenance	1,992	2,732	6,416	7,370
Depreciation and amortization	1,624	1,289	4,988	3,312
Taxes other than income taxes	468	452	1,337	1,299
Total operating expenses	7,117	8,087	24,758	22,387
Gain on sales of assets and businesses	65	3	147	16
Operating income	1,858	769	2,104	2,554
Other income and (deductions)				
Interest expense, net	(391)	(398)	(1,161)	(1,222)
Interest expense to affiliates	(6)	(6)	(19)	(19)
Other, net	(55)	421	751	352
Total other income and (deductions)	(452)	17	(429)	(889)
Income before income taxes	1,406	786	1,675	1,665
Income taxes	174	216	229	141
Equity in losses of unconsolidated affiliates	(3)	(1)	(5)	(5)
Net income	1,229	569	1,441	1,519
Net income (loss) attributable to noncontrolling interests	26	68	126	(85)
Net income attributable to common shareholders	$ 1,203	$ 501	$ 1,315	$ 1,604
Comprehensive income, net of income taxes				
Net income	$ 1,229	$ 569	$ 1,441	$ 1,519
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(1)	(10)	(4)	(30)
Actuarial loss reclassified to periodic benefit cost	56	49	167	142
Pension and non-pension postretirement benefit plan valuation adjustment	14	(13)	15	(17)
Unrealized loss on cash flow hedges	—	(1)	(1)	(2)
Unrealized (loss) gain on foreign currency translation	(3)	3	—	(3)
Other comprehensive income	66	28	177	90
Comprehensive income	1,295	597	1,618	1,609
Comprehensive income (loss) attributable to noncontrolling interests	26	68	126	(85)
Comprehensive income attributable to common shareholders	$ 1,269	$ 529	$ 1,492	$ 1,694
Average shares of common stock outstanding:				
Basic	979	976	978	976
Assumed exercise and/or distributions of stock-based awards	1	1	1	—
Diluted(a)	980	977	979	976
Earnings per average common share				
Basic	$ 1.23	$ 0.51	$ 1.34	$ 1.64
Diluted	$ 1.23	$ 0.51	$ 1.34	$ 1.64

(a) The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was zero for the three and nine months ended September 30, 2021 and approximately 1 million for the three and nine months ended September 30, 2020, respectively.

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
(In millions)	2021	2020
Cash flows from operating activities		
Net income	$ 1,441	$ 1,519
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	6,204	4,419
Asset impairments	541	567
Gain on sales of assets and businesses	(147)	(16)
Deferred income taxes and amortization of investment tax credits	(45)	164
Net fair value changes related to derivatives	(1,244)	(448)
Net realized and unrealized gains on NDT funds	(383)	(59)
Net unrealized losses on equity investments	83	—
Other non-cash operating activities	(293)	988
Changes in assets and liabilities:		
Accounts receivable	(254)	1,195
Inventories	(101)	(67)
Accounts payable and accrued expenses	354	(519)
Option premiums paid, net	(186)	(131)
Collateral received, net	2,111	644
Income taxes	250	(31)
Pension and non-pension postretirement benefit contributions	(602)	(580)
Other assets and liabilities	(3,588)	(3,423)
Net cash flows provided by operating activities	4,141	4,222
Cash flows from investing activities		
Capital expenditures	(5,970)	(5,606)
Proceeds from NDT fund sales	5,766	3,370
Investment in NDT funds	(5,900)	(3,438)
Collection of DPP	3,052	2,518
Proceeds from sales of assets and businesses	801	46
Other investing activities	40	(2)
Net cash flows used in investing activities	(2,211)	(3,112)
Cash flows from financing activities		
Changes in short-term borrowings	(744)	(689)
Proceeds from short-term borrowings with maturities greater than 90 days	1,380	500
Issuance of long-term debt	3,406	6,756
Retirement of long-term debt	(1,618)	(5,158)
Dividends paid on common stock	(1,121)	(1,119)
Acquisition of CENG noncontrolling interest	(885)	—
Proceeds from employee stock plans	63	62
Other financing activities	(93)	(104)
Net cash flows provided by financing activities	388	248
Increase in cash, restricted cash, and cash equivalents	2,318	1,358
Cash, restricted cash, and cash equivalents at beginning of period	1,166	1,122
Cash, restricted cash, and cash equivalents at end of period	$ 3,484	$ 2,480
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (334)	$ (11)
Increase in DPP	2,933	3,275
Increase in PP&E related to ARO update	574	775

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 2,957		$ 663
Restricted cash and cash equivalents		473		438
Accounts receivable				
Customer accounts receivable	3,530		3,597	
Customer allowance for credit losses	(409)		(366)	
Customer accounts receivable, net		3,121		3,231
Other accounts receivable	1,616		1,469	
Other allowance for credit losses	(77)		(71)	
Other accounts receivable, net		1,539		1,398
Mark-to-market derivative assets		1,507		644
Unamortized energy contract assets		36		38
Inventories, net				
Fossil fuel and emission allowances		343		297
Materials and supplies		1,475		1,425
Regulatory assets		1,258		1,228
Renewable energy credits		492		633
Assets held for sale		11		958
Other		1,665		1,609
Total current assets		14,877		12,562
Property, plant, and equipment (net of accumulated depreciation and amortization of $30,049 and $26,727 as of September 30, 2021 and December 31, 2020, respectively)		82,852		82,584
Deferred debits and other assets				
Regulatory assets		8,628		8,759
Nuclear decommissioning trust funds		15,404		14,464
Investments		435		440
Goodwill		6,677		6,677
Mark-to-market derivative assets		665		555
Unamortized energy contract assets		265		294
Other		2,818		2,982
Total deferred debits and other assets		34,892		34,171
Total assets[(a)]		$ 132,621		$ 129,317

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 2,667	$ 2,031
Long-term debt due within one year	3,375	1,819
Accounts payable	3,694	3,562
Accrued expenses	1,949	2,078
Payables to affiliates	5	5
Regulatory liabilities	460	581
Mark-to-market derivative liabilities	1,717	295
Unamortized energy contract liabilities	92	100
Renewable energy credit obligation	684	661
Liabilities held for sale	3	375
Other	1,180	1,264
Total current liabilities	15,826	12,771
Long-term debt	35,269	35,093
Long-term debt to financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,816	13,035
Asset retirement obligations	12,907	12,300
Pension obligations	3,777	4,503
Non-pension postretirement benefit obligations	1,980	2,011
Spent nuclear fuel obligation	1,209	1,208
Regulatory liabilities	9,448	9,485
Mark-to-market derivative liabilities	721	473
Unamortized energy contract liabilities	169	238
Other	2,850	2,942
Total deferred credits and other liabilities	46,877	46,195
Total liabilities[(a)]	98,362	94,449
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 978 shares and 976 shares outstanding at September 30, 2021 and December 31, 2020, respectively)	20,271	19,373
Treasury stock, at cost (2 shares at September 30, 2021 and December 31, 2020)	(123)	(123)
Retained earnings	16,926	16,735
Accumulated other comprehensive loss, net	(3,223)	(3,400)
Total shareholders' equity	33,851	32,585
Noncontrolling interests	408	2,283
Total equity	34,259	34,868
Total liabilities and shareholders' equity	$ 132,621	$ 129,317

(a) Exelon's consolidated assets include $2,722 million and $10,200 million at September 30, 2021 and December 31, 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $1,088 million and $3,598 million at September 30, 2021 and December 31, 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 17 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021						
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2020	977,466	$ 19,373	$ (123)	$ 16,735	$ (3,400)	$ 2,283	$ 34,868
Net (loss) income	—	—	—	(289)	—	25	(264)
Long-term incentive plan activity	640	5	—	—	—	—	5
Employee stock purchase plan issuances	902	34	—	—	—	—	34
Changes in equity of noncontrolling interests	—	—	—	—	—	(10)	(10)
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	54	—	54
Balance, March 31, 2021	979,008	$ 19,412	$ (123)	$ 16,072	$ (3,346)	$ 2,298	$ 34,313
Net income	—	—	—	401	—	75	476
Long-term incentive plan activity	237	24	—	—	—	—	24
Employee stock purchase plan issuances	420	18	—	—	—	—	18
Changes in equity of noncontrolling interests	—	—	—	—	—	(13)	(13)
Common stock dividends ($0.38/common share)	—	—	—	(375)	—	—	(375)
Other comprehensive income, net of income taxes	—	—	—	—	57	—	57
Balance, June 30, 2021	979,665	$ 19,454	$ (123)	$ 16,098	$ (3,289)	$ 2,360	$ 34,500
Net income	—	—	—	1,203	—	26	1,229
Long-term incentive plan activity	94	9	—	—	—	—	9
Employee stock purchase plan issuances	391	18	—	—	—	—	18
Changes in equity of noncontrolling interests	—	—	—	—	—	(13)	(13)
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 ($0.38/common share)	—	—	—	(375)	—	—	(375)
Other comprehensive income net of income taxes	—	—	—	—	66	—	66
Balance, September 30, 2021	980,150	$ 20,271	$ (123)	$ 16,926	$ (3,223)	$ 408	$ 34,259

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30, 2020						
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Shareholders' Equity
Balance, December 31, 2019	974,416	$ 19,274	$ (123)	$ 16,267	$ (3,194)	$ 2,349	$ 34,573
Net income (loss)	—	—	—	582	—	(206)	376
Long-term incentive plan activity	1,354	(4)	—	—	—	—	(4)
Employee stock purchase plan issuances	470	31	—	—	—	—	31
Changes in equity of noncontrolling interests	—	—	—	—	—	(9)	(9)
Sale of noncontrolling interests	—	2	—	—	—	—	2
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	21	—	21
Balance, March 31, 2020	976,240	$ 19,303	$ (123)	$ 16,475	$ (3,173)	$ 2,134	$ 34,616
Net income	—	—	—	521	—	53	574
Long-term incentive plan activity	148	17	—	—	—	—	17
Employee stock purchase plan issuances	(51)	15	—	—	—	—	15
Changes in equity of noncontrolling interests	—	—	—	—	—	(19)	(19)
Sale of noncontrolling interests	—	1	—	—	—	—	1
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	41	—	41
Balance, June 30, 2020	976,337	$ 19,336	$ (123)	$ 16,622	$ (3,132)	$ 2,168	$ 34,871
Net Income	—	—	—	501	—	68	569
Long-term incentive plan activity	68	10	—	—	—	—	10
Employee stock purchase plan issuances	1,000	16	—	—	—	—	16
Changes in equity of noncontrolling interests	—	—	—	—	—	(17)	(17)
Common stock dividends ($0.38/common share)	—	—	—	(374)	—	—	(374)
Other comprehensive income, net of income taxes	—	—	—	—	28	—	28
Balance, September 30, 2020	977,405	$ 19,362	$ (123)	$ 16,749	$ (3,104)	$ 2,219	$ 35,103

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Operating revenues	$ 4,082	$ 4,328	$ 13,245	$ 12,340
Operating revenues from affiliates	324	331	872	932
Total operating revenues	4,406	4,659	14,117	13,272
Operating expenses				
Purchased power and fuel	1,542	2,311	8,103	6,967
Purchased power and fuel from affiliates	4	3	—	(6)
Operating and maintenance	761	1,605	2,955	3,779
Operating and maintenance from affiliates	177	132	458	409
Depreciation and amortization	866	558	2,735	1,161
Taxes other than income taxes	115	118	354	364
Total operating expenses	3,465	4,727	14,605	12,674
Gain on sales of assets and businesses	65	—	144	12
Operating income (loss)	1,006	(68)	(344)	610
Other income and (deductions)				
Interest expense, net	(73)	(72)	(214)	(251)
Interest expense to affiliates	(4)	(8)	(11)	(26)
Other, net	(115)	367	561	199
Total other income and (deductions)	(192)	287	336	(78)
Income (loss) before income taxes	814	219	(8)	532
Income taxes	177	100	108	41
Equity in losses of unconsolidated affiliates	(4)	(2)	(6)	(6)
Net income (loss)	633	117	(122)	485
Net income (loss) attributable to noncontrolling interests	26	68	125	(85)
Net income (loss) attributable to membership interest	$ 607	$ 49	$ (247)	$ 570
Comprehensive income (loss), net of income taxes				
Net income (loss)	$ 633	$ 117	$ (122)	$ 485
Other comprehensive (loss) income, net of income taxes				
Unrealized loss on cash flow hedges	—	—	(1)	(1)
Unrealized (loss) gain on foreign currency translation	(4)	3	—	(3)
Other comprehensive (loss) income, net of income taxes	(4)	3	(1)	(4)
Comprehensive income (loss)	629	120	(123)	481
Comprehensive income (loss) attributable to noncontrolling interests	26	68	125	(85)
Comprehensive income (loss) attributable to membership interest	$ 603	$ 52	$ (248)	$ 566

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	2020
Cash flows from operating activities		
Net (loss) income	$ (122)	$ 485
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	3,951	2,266
Asset impairments	537	552
Gain on sales of assets and businesses	(144)	(12)
Deferred income taxes and amortization of investment tax credits	(204)	(51)
Net fair value changes related to derivatives	(1,244)	(448)
Net realized and unrealized gains on NDT funds	(383)	(59)
Net unrealized losses on equity investments	83	—
Other non-cash operating activities	(582)	293
Changes in assets and liabilities:		
Accounts receivable	(207)	1,463
Receivables from and payables to affiliates, net	82	75
Inventories	(29)	(65)
Accounts payable and accrued expenses	357	(619)
Option premiums paid, net	(186)	(131)
Collateral received, net	1,974	640
Income taxes	177	112
Pension and non-pension postretirement benefit contributions	(237)	(249)
Other assets and liabilities	(2,849)	(2,889)
Net cash flows provided by operating activities	974	1,363
Cash flows from investing activities		
Capital expenditures	(1,086)	(1,212)
Proceeds from NDT fund sales	5,766	3,370
Investment in NDT funds	(5,900)	(3,438)
Collection of DPP	3,052	2,518
Proceeds from sales of assets and businesses	802	46
Other investing activities	5	5
Net cash flows provided by investing activities	2,639	1,289
Cash flows from financing activities		
Changes in short-term borrowings	(340)	(280)
Proceeds from short-term borrowings with maturities greater than 90 days	880	500
Issuance of long-term debt	152	2,405
Retirement of long-term debt	(89)	(3,613)
Changes in Exelon intercompany money pool	(285)	—
Acquisition of CENG noncontrolling interest	(885)	—
Distributions to member	(1,373)	(1,406)
Contributions from member	64	64
Other financing activities	(45)	(48)
Net cash flows used in financing activities	(1,921)	(2,378)
Increase in cash, restricted cash, and cash equivalents	1,692	274
Cash, restricted cash, and cash equivalents at beginning of period	327	449
Cash, restricted cash, and cash equivalents at end of period	$ 2,019	$ 723
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (77)	$ (77)
Increase in DPP	2,933	3,275
Increase in PP&E related to ARO update	550	775

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 1,957		$ 226
Restricted cash and cash equivalents		62		89
Accounts receivable				
Customer accounts receivable	1,412		1,330	
Customer allowance for credit losses	(84)		(32)	
Customer accounts receivable, net		1,328		1,298
Other accounts receivable	465		352	
Other allowance for credit losses	(4)		—	
Other accounts receivable, net		461		352
Mark-to-market derivative assets		1,505		644
Receivables from affiliates		184		153
Unamortized energy contract assets		36		38
Inventories, net				
Fossil fuel and emission allowances		240		233
Materials and supplies		998		978
Renewable energy credits		486		621
Assets held for sale		11		958
Other		1,319		1,357
Total current assets		8,587		6,947
Property, plant, and equipment (net of accumulated depreciation and amortization of $15,966 and $13,370 as of September 30, 2021 and December 31, 2020, respectively)		19,574		22,214
Deferred debits and other assets				
Nuclear decommissioning trust funds		15,404		14,464
Investments		165		184
Goodwill		47		47
Mark-to-market derivative assets		664		555
Prepaid pension asset		1,702		1,558
Unamortized energy contract assets		265		293
Deferred income taxes		13		6
Other		1,589		1,826
Total deferred debits and other assets		19,849		18,933
Total assets[a]		$ 48,010		$ 48,094

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 1,380	$ 840
Long-term debt due within one year	1,216	197
Accounts payable	1,612	1,253
Accrued expenses	691	788
Payables to affiliates	154	107
Borrowings from Exelon intercompany money pool	—	285
Mark-to-market derivative liabilities	1,709	262
Unamortized energy contract liabilities	2	7
Renewable energy credit obligation	682	661
Liabilities held for sale	3	375
Other	347	444
Total current liabilities	7,796	5,219
Long-term debt	4,593	5,566
Long-term debt to affiliates	321	324
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,685	3,656
Asset retirement obligations	12,635	12,054
Non-pension postretirement benefit obligations	857	858
Spent nuclear fuel obligation	1,209	1,208
Payables to affiliates	3,143	3,017
Mark-to-market derivative liabilities	511	205
Unamortized energy contract liabilities	1	3
Other	1,224	1,308
Total deferred credits and other liabilities	23,265	22,309
Total liabilities[(a)]	35,975	33,418
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	10,480	9,624
Undistributed earnings	1,185	2,805
Accumulated other comprehensive loss, net	(31)	(30)
Total member's equity	11,634	12,399
Noncontrolling interests	401	2,277
Total equity	12,035	14,676
Total liabilities and equity	$ 48,010	$ 48,094

(a) Generation's consolidated assets include $2,704 million and $10,182 million at September 30, 2021 and December 31, 2020, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $1,078 million and $3,572 million at September 30, 2021 and December 31, 2020, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 17 — Variable Interest Entities for additional information.

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

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

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited)

	Nine Months Ended September 30, 2020				
	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2019	$ 9,566	$ 3,950	$ (32)	$ 2,346	$ 15,830
Net income (loss)	—	45	—	(206)	(161)
Changes in equity of noncontrolling interests	—	—	—	(11)	(11)
Sale of noncontrolling interests	2	—	—	—	2
Distributions to member	—	(468)	—	—	(468)
Other comprehensive loss, net of income taxes	—	—	(9)	—	(9)
Balance, March 31, 2020	$ 9,568	$ 3,527	$ (41)	$ 2,129	$ 15,183
Net income	—	476	—	53	529
Changes in equity of noncontrolling interests	—	—	—	(19)	(19)
Sale of noncontrolling interests	1	—	—	—	1
Distributions to member	—	(469)	—	—	(469)
Other comprehensive income, net of income taxes	—	—	2	—	2
Balance, June 30, 2020	$ 9,569	$ 3,534	$ (39)	$ 2,163	$ 15,227
Net income	—	49	—	68	117
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Contribution from member	64	—	—	—	64
Distributions to member	—	(469)	—	—	(469)
Other comprehensive income, net of income taxes	—	—	3	—	3
Balance, September 30, 2020	$ 9,633	$ 3,114	$ (36)	$ 2,213	$ 14,924

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Electric operating revenues	$ 1,812	$ 1,666	$ 4,789	$ 4,519
Revenues from alternative revenue programs	(32)	(38)	32	(51)
Operating revenues from affiliates	9	15	19	31
Total operating revenues	1,789	1,643	4,840	4,499
Operating expenses				
Purchased power	610	535	1,472	1,305
Purchased power from affiliate	93	71	256	252
Operating and maintenance	257	252	752	964
Operating and maintenance from affiliates	73	69	217	209
Depreciation and amortization	304	294	893	841
Taxes other than income taxes	91	81	243	227
Total operating expenses	1,428	1,302	3,833	3,798
Operating income	361	341	1,007	701
Other income and (deductions)				
Interest expense, net	(95)	(92)	(282)	(277)
Interest expense to affiliates	(3)	(3)	(10)	(10)
Other, net	13	10	35	32
Total other deductions	(85)	(85)	(257)	(255)
Income before income taxes	276	256	750	446
Income taxes	56	60	141	142
Net income	$ 220	$ 196	$ 609	$ 304
Comprehensive income	$ 220	$ 196	$ 609	$ 304

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net income	$ 609	$ 304
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	893	841
Asset impairments	—	15
Deferred income taxes and amortization of investment tax credits	211	205
Other non-cash operating activities	95	354
Changes in assets and liabilities:		
Accounts receivable	(72)	(104)
Receivables from and payables to affiliates, net	(16)	(13)
Inventories	(6)	(2)
Accounts payable and accrued expenses	(36)	21
Collateral received, net	68	3
Income taxes	(9)	(22)
Pension and non-pension postretirement benefit contributions	(176)	(145)
Other assets and liabilities	(376)	(380)
Net cash flows provided by operating activities	1,185	1,077
Cash flows from investing activities		
Capital expenditures	(1,723)	(1,583)
Other investing activities	20	—
Net cash flows used in investing activities	(1,703)	(1,583)
Cash flows from financing activities		
Changes in short-term borrowings	(323)	11
Issuance of long-term debt	1,150	1,000
Retirement of long-term debt	(350)	(500)
Dividends paid on common stock	(380)	(374)
Contributions from parent	593	488
Other financing activities	(16)	(14)
Net cash flows provided by financing activities	674	611
Increase in cash, restricted cash, and cash equivalents	156	105
Cash, restricted cash, and cash equivalents at beginning of period	405	403
Cash, restricted cash, and cash equivalents at end of period	$ 561	$ 508
Supplemental cash flow information		
(Decrease) increase in capital expenditures not paid	$ (118)	$ 49

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	241	$	83
Restricted cash and cash equivalents		276		279
Accounts receivable				
Customer accounts receivable	685		656	
Customer allowance for credit losses	(88)		(97)	
Customer accounts receivable, net		597		559
Other accounts receivable	252		239	
Other allowance for credit losses	(19)		(21)	
Other accounts receivable, net		233		218
Receivables from affiliates		41		22
Inventories, net		174		170
Regulatory assets		287		279
Other		77		49
Total current assets		1,926		1,659
Property, plant, and equipment (net of accumulated depreciation and amortization of $5,995 and $5,672 as of September 30, 2021 and December 31, 2020, respectively)		25,496		24,557
Deferred debits and other assets				
Regulatory assets		1,834		1,749
Investments		6		6
Goodwill		2,625		2,625
Receivables from affiliates		2,597		2,541
Prepaid pension asset		1,111		1,022
Other		407		307
Total deferred debits and other assets		8,580		8,250
Total assets	$	36,002	$	34,466

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 323
Long-term debt due within one year	—	350
Accounts payable	596	683
Accrued expenses	311	390
Payables to affiliates	131	96
Customer deposits	97	86
Regulatory liabilities	197	289
Mark-to-market derivative liabilities	5	33
Other	165	143
Total current liabilities	1,502	2,393
Long-term debt	9,772	8,633
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,629	4,341
Asset retirement obligations	144	126
Non-pension postretirement benefits obligations	183	173
Regulatory liabilities	6,604	6,403
Mark-to-market derivative liabilities	209	268
Other	603	595
Total deferred credits and other liabilities	12,372	11,906
Total liabilities	23,851	23,137
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	8,878	8,285
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	3,324	3,095
Total shareholders' equity	12,151	11,329
Total liabilities and shareholders' equity	$ 36,002	$ 34,466

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021				
(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2020	$ 1,588	$ 8,285	$ (1,639)	$ 3,095	$ 11,329
Net income	—	—	197	—	197
Appropriation of retained earnings for future dividends	—	—	(197)	197	—
Common stock dividends	—	—	—	(127)	(127)
Contributions from parent	—	198	—	—	198
Balance, March 31, 2021	$ 1,588	$ 8,483	$ (1,639)	$ 3,165	$ 11,597
Net income	—	—	192	—	192
Appropriation of retained earnings for future dividends	—	—	(192)	192	—
Common stock dividends	—	—	—	(126)	(126)
Contributions from parent	—	197	—	—	197
Balance, June 30, 2021	$ 1,588	$ 8,680	$ (1,639)	$ 3,231	$ 11,860
Net income	—	—	220	—	220
Appropriation of retained earnings for future dividends	—	—	(220)	220	—
Common stock dividends	—	—	—	(127)	(127)
Contributions from parent	—	198	—	—	198
Balance, September 30, 2021	$ 1,588	$ 8,878	$ (1,639)	$ 3,324	$ 12,151

	Nine Months Ended September 30, 2020				
(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2019	$ 1,588	$ 7,572	$ (1,639)	$ 3,156	$ 10,677
Net income	—	—	168	—	168
Appropriation of retained earnings for future dividends	—	—	(168)	168	—
Common stock dividends	—	—	—	(125)	(125)
Contributions from parent	—	125	—	—	125
Balance, March 31, 2020	$ 1,588	$ 7,697	$ (1,639)	$ 3,199	$ 10,845
Net loss	—	—	(61)	—	(61)
Common stock dividends	—	—	—	(124)	(124)
Contributions from parent	—	124	—	—	124
Balance, June 30, 2020	$ 1,588	$ 7,821	$ (1,700)	$ 3,075	$ 10,784
Net income	—	—	196	—	196
Appropriation of retained earnings for future dividends	—	—	(196)	196	—
Common stock dividends	—	—	—	(124)	(124)
Contributions from parent	—	239	—	—	239
Balance, September 30, 2020	$ 1,588	$ 8,060	$ (1,700)	$ 3,147	$ 11,095

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Electric operating revenues	$ 757	$ 751	$ 2,008	$ 1,931
Natural gas operating revenues	56	54	365	358
Revenues from alternative revenue programs	3	5	20	10
Operating revenues from affiliates	2	3	6	7
Total operating revenues	818	813	2,399	2,306
Operating expenses				
Purchased power	206	190	540	495
Purchased fuel	11	12	119	129
Purchased power from affiliate	60	67	141	144
Operating and maintenance	220	214	580	628
Operating and maintenance from affiliates	43	37	126	114
Depreciation and amortization	86	85	259	259
Taxes other than income taxes	51	53	143	131
Total operating expenses	677	658	1,908	1,900
Operating income	141	155	491	406
Other income and (deductions)				
Interest expense, net	(37)	(36)	(110)	(100)
Interest expense to affiliates	(3)	(3)	(9)	(8)
Other, net	7	6	20	12
Total other income and (deductions)	(33)	(33)	(99)	(96)
Income before income taxes	108	122	392	310
Income taxes	(3)	(16)	9	(7)
Net income	$ 111	$ 138	$ 383	$ 317
Comprehensive income	$ 111	$ 138	$ 383	$ 317

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net income	$ 383	$ 317
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	259	259
Deferred income taxes and amortization of investment tax credits	19	(5)
Other non-cash operating activities	4	27
Changes in assets and liabilities:		
Accounts receivable	47	(2)
Receivables from and payables to affiliates, net	16	(7)
Inventories	(21)	(3)
Accounts payable and accrued expenses	(23)	32
Income taxes	55	48
Pension and non-pension postretirement benefit contributions	(15)	(18)
Other assets and liabilities	(87)	(13)
Net cash flows provided by operating activities	637	635
Cash flows from investing activities		
Capital expenditures	(878)	(824)
Changes in Exelon intercompany money pool	—	68
Other investing activities	5	4
Net cash flows used in investing activities	(873)	(752)
Cash flows from financing activities		
Issuance of long-term debt	750	350
Retirement of long-term debt	(300)	—
Changes in Exelon intercompany money pool	(40)	—
Dividends paid on common stock	(254)	(255)
Contributions from parent	414	248
Other financing activities	(8)	(4)
Net cash flows provided by financing activities	562	339
Increase in cash, restricted cash, and cash equivalents	326	222
Cash, restricted cash, and cash equivalents at beginning of period	26	27
Cash, restricted cash, and cash equivalents at end of period	$ 352	$ 249
Supplemental cash flow information		
Increase in capital expenditures not paid	$ 25	$ 28

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 344		$ 19
Restricted cash and cash equivalents		8		7
Accounts receivable				
Customer accounts receivable	411		511	
Customer allowance for credit losses	(101)		(116)	
Customer accounts receivable, net		310		395
Other accounts receivable	124		130	
Other allowance for credit losses	(7)		(8)	
Other accounts receivable, net		117		122
Receivables from affiliates		9		2
Inventories, net				
Fossil fuel		47		33
Materials and supplies		45		38
Prepaid utility taxes		34		—
Regulatory assets		35		25
Other		29		21
Total current assets		978		662
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,921 and $3,843 as of September 30, 2021 and December 31, 2020, respectively)		10,841		10,181
Deferred debits and other assets				
Regulatory assets		901		776
Investments		34		30
Receivables from affiliates		546		475
Prepaid pension asset		386		375
Other		47		32
Total deferred debits and other assets		1,914		1,688
Total assets		$ 13,733		$ 12,531

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 350	$ 300
Accounts payable	487	479
Accrued expenses	168	129
Payables to affiliates	60	50
Borrowings from Exelon intercompany money pool	—	40
Customer deposits	48	59
Regulatory liabilities	102	121
Other	31	30
Total current liabilities	1,246	1,208
Long-term debt	3,846	3,453
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,385	2,242
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	288	286
Regulatory liabilities	588	503
Other	92	93
Total deferred credits and other liabilities	3,382	3,153
Total liabilities	8,658	7,998
Commitments and contingencies		
Shareholder’s equity		
Common stock	3,428	3,014
Retained earnings	1,647	1,519
Total shareholder’s equity	5,075	4,533
Total liabilities and shareholder's equity	$ 13,733	$ 12,531

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	$ 3,014	$ 1,519	$ 4,533
Net income	—	167	167
Common stock dividends	—	(85)	(85)
Balance, March 31, 2021	$ 3,014	$ 1,601	$ 4,615
Net income	—	104	104
Common stock dividends	—	(84)	(84)
Contributions from parent	395	—	395
Balance, June 30, 2021	$ 3,409	$ 1,621	$ 5,030
Net income	—	111	111
Common stock dividends	—	(85)	(85)
Contributions from parent	19	—	19
Balance, September 30, 2021	$ 3,428	$ 1,647	$ 5,075

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 2,766	$ 1,412	$ 4,178
Net income	—	140	140
Common stock dividends	—	(85)	(85)
Contributions from parent	231	—	231
Balance, March 31, 2020	$ 2,997	$ 1,467	$ 4,464
Net income	—	39	39
Common stock dividends	—	(85)	(85)
Balance, June 30, 2020	$ 2,997	$ 1,421	$ 4,418
Net income	—	138	138
Common stock dividends	—	(85)	(85)
Contributions from parent	17	—	17
Balance, September 30, 2020	$ 3,014	$ 1,474	$ 4,488

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Electric operating revenues	$ 694	$ 649	$ 1,874	$ 1,775
Natural gas operating revenues	93	85	549	503
Revenues from alternative revenue programs	(24)	(9)	(17)	(10)
Operating revenues from affiliates	7	6	20	16
Total operating revenues	770	731	2,426	2,284
Operating expenses				
Purchased power	206	155	501	376
Purchased fuel	20	12	146	106
Purchased power and fuel from affiliate	64	83	193	249
Operating and maintenance	159	152	458	445
Operating and maintenance from affiliates	46	39	137	122
Depreciation and amortization	142	133	434	405
Taxes other than income taxes	72	68	211	200
Total operating expenses	709	642	2,080	1,903
Operating income	61	89	346	381
Other income and (deductions)				
Interest expense, net	(36)	(34)	(103)	(99)
Other, net	7	6	23	17
Total other income and (deductions)	(29)	(28)	(80)	(82)
Income before income taxes	32	61	266	299
Income taxes	(4)	8	(24)	26
Net income	$ 36	$ 53	$ 290	$ 273
Comprehensive income	$ 36	$ 53	$ 290	$ 273

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net income	$ 290	$ 273
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	434	405
Deferred income taxes and amortization of investment tax credits	7	35
Other non-cash operating activities	77	82
Changes in assets and liabilities:		
Accounts receivable	92	(19)
Receivables from and payables to affiliates, net	(13)	(27)
Inventories	(30)	2
Accounts payable and accrued expenses	14	53
Income taxes	3	46
Pension and non-pension postretirement benefit contributions	(76)	(74)
Other assets and liabilities	(129)	(50)
Net cash flows provided by operating activities	669	726
Cash flows from investing activities		
Capital expenditures	(907)	(838)
Other investing activities	13	—
Net cash flows used in investing activities	(894)	(838)
Cash flows from financing activities		
Changes in short-term borrowings	—	(76)
Issuance of long-term debt	600	400
Retirement of long-term debt	(300)	—
Dividends paid on common stock	(219)	(186)
Contributions from parent	257	284
Other financing activities	(6)	(8)
Net cash flows provided by financing activities	332	414
Increase in cash, restricted cash, and cash equivalents	107	302
Cash, restricted cash, and cash equivalents at beginning of period	145	25
Cash, restricted cash, and cash equivalents at end of period	$ 252	$ 327
Supplemental cash flow information		
(Decrease) increase in capital expenditures not paid	$ (70)	$ 7

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	225	$	144
Restricted cash and cash equivalents		27		1
Accounts receivable				
Customer accounts receivable	351		487	
Customer allowance for credit losses	(31)		(35)	
Customer accounts receivable, net		320		452
Other accounts receivable	149		117	
Other allowance for credit losses	(8)		(9)	
Other accounts receivable, net		141		108
Receivables from affiliates		2		3
Inventories, net				
Fossil fuel		46		25
Materials and supplies		50		41
Regulatory assets		185		168
Other		8		6
Total current assets		1,004		948
Property, plant, and equipment (net of accumulated depreciation and amortization of $4,212 and $4,034 as of September 30, 2021 and December 31, 2020, respectively)		10,374		9,872
Deferred debits and other assets				
Regulatory assets		468		481
Investments		15		10
Prepaid pension asset		289		270
Other		47		69
Total deferred debits and other assets		819		830
Total assets	$	12,197	$	11,650

BALTIMORE GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 250	$ 300
Accounts payable	291	346
Accrued expenses	204	205
Payables to affiliates	49	61
Customer deposits	98	110
Regulatory liabilities	34	30
Other	81	91
Total current liabilities	1,007	1,143
Long-term debt	3,710	3,364
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,656	1,521
Asset retirement obligations	26	23
Non-pension postretirement benefits obligations	177	189
Regulatory liabilities	989	1,109
Other	107	104
Total deferred credits and other liabilities	2,955	2,946
Total liabilities	7,672	7,453
Commitments and contingencies		
Shareholder's equity		
Common stock	2,575	2,318
Retained earnings	1,950	1,879
Total shareholder's equity	4,525	4,197
Total liabilities and shareholder's equity	$ 12,197	$ 11,650

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	$ 2,318	$ 1,879	$ 4,197
Net income	—	209	209
Common stock dividends	—	(74)	(74)
Balance, March 31, 2021	$ 2,318	$ 2,014	$ 4,332
Net income	—	45	45
Common stock dividends	—	(72)	(72)
Balance, June 30, 2021	$ 2,318	$ 1,987	$ 4,305
Net income	—	36	36
Common stock dividends	—	(73)	(73)
Contributions from parent	257	—	257
Balance, September 30, 2021	$ 2,575	$ 1,950	$ 4,525

(In millions)	Nine Months Ended September 30, 2020		
	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 1,907	$ 1,776	$ 3,683
Net income	—	181	181
Common stock dividends	—	(62)	(62)
Balance, March 31, 2020	$ 1,907	$ 1,895	$ 3,802
Net income	—	39	39
Common stock dividends	—	(62)	(62)
Contributions from parent	26	—	26
Balance, June 30, 2020	$ 1,933	$ 1,872	$ 3,805
Net income	—	53	53
Common stock dividends	—	(62)	(62)
Contributions from parent	258	—	258
Balance, September 30, 2020	$ 2,191	$ 1,863	$ 4,054

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Electric operating revenues	$ 1,438	$ 1,308	$ 3,632	$ 3,440
Natural gas operating revenues	23	23	118	116
Revenues from alternative revenue programs	6	31	94	(15)
Operating revenues from affiliates	3	6	10	13
Total operating revenues	1,470	1,368	3,854	3,554
Operating expenses				
Purchased power	431	393	1,087	979
Purchased fuel	9	7	50	49
Purchased power from affiliates	100	106	277	288
Operating and maintenance	235	237	668	702
Operating and maintenance from affiliates	43	38	122	111
Depreciation and amortization	210	200	614	585
Taxes other than income taxes	127	121	349	343
Total operating expenses	1,155	1,102	3,167	3,057
Gain on sales of assets	—	—	—	2
Operating income	315	266	687	499
Other income and (deductions)				
Interest expense, net	(67)	(67)	(201)	(201)
Other, net	16	16	52	42
Total other income and (deductions)	(51)	(51)	(149)	(159)
Income before income taxes	264	215	538	340
Income taxes	(2)	(1)	3	(77)
Equity in earnings of unconsolidated affiliate	—	—	—	1
Net income	$ 266	$ 216	$ 535	$ 418
Comprehensive income	$ 266	$ 216	$ 535	$ 418

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net income	$ 535	$ 418
Adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	614	585
Deferred income taxes and amortization of investment tax credits	—	(99)
Other non-cash operating activities	(35)	115
Changes in assets and liabilities:		
Accounts receivable	(112)	(121)
Receivables from and payables to affiliates, net	(19)	(26)
Inventories	(13)	(2)
Accounts payable and accrued expenses	19	57
Income taxes	17	(14)
Pension and non-pension postretirement benefit contributions	(43)	(35)
Other assets and liabilities	(120)	(61)
Net cash flows provided by operating activities	843	817
Cash flows from investing activities		
Capital expenditures	(1,299)	(1,072)
Other investing activities	(1)	3
Net cash flows used in investing activities	(1,300)	(1,069)
Cash flows from financing activities		
Changes in short-term borrowings	(81)	(208)
Issuance of long-term debt	750	601
Retirement of long-term debt	(255)	(119)
Changes in Exelon intercompany money pool	(5)	9
Distributions to member	(605)	(451)
Contributions from member	667	493
Other financing activities	(12)	(10)
Net cash flows provided by financing activities	459	315
Increase in cash, restricted cash, and cash equivalents	2	63
Cash, restricted cash, and cash equivalents at beginning of period	160	181
Cash, restricted cash, and cash equivalents at end of period	$ 162	$ 244
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (74)	$ (5)

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents		$ 82		$ 111
Restricted cash and cash equivalents		71		39
Accounts receivable				
Customer accounts receivable	671		611	
Customer allowance for credit losses	(105)		(86)	
Customer accounts receivable, net		566		525
Other accounts receivable	300		260	
Other allowance for credit losses	(40)		(33)	
Other accounts receivable, net		260		227
Receivables from affiliates		3		8
Inventories, net				
Fossil fuel		10		6
Materials and supplies		207		198
Regulatory assets		434		440
Other		57		45
Total current assets		1,690		1,599
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,995 and $1,811 as of September 30, 2021 and December 31, 2020, respectively)		16,163		15,377
Deferred debits and other assets				
Regulatory assets		1,848		1,933
Investments		146		140
Goodwill		4,005		4,005
Prepaid pension asset		357		365
Deferred income taxes		10		10
Other		283		307
Total deferred debits and other assets		6,649		6,760
Total assets(a)		$ 24,502		$ 23,736

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 287	$ 368
Long-term debt due within one year	405	347
Accounts payable	479	539
Accrued expenses	300	299
Payables to affiliates	80	104
Borrowings from Exelon intercompany money pool	16	21
Customer deposits	82	106
Regulatory liabilities	122	137
Unamortized energy contract liabilities	90	92
Other	154	141
Total current liabilities	2,015	2,154
Long-term debt	7,077	6,659
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,635	2,439
Asset retirement obligations	69	59
Non-pension postretirement benefit obligations	71	86
Regulatory liabilities	1,237	1,438
Unamortized energy contract liabilities	168	235
Other	589	622
Total deferred credits and other liabilities	4,769	4,879
Total liabilities(a)	13,861	13,692
Commitments and contingencies		
Member's equity		
Membership interest	10,779	10,112
Undistributed losses	(138)	(68)
Total member's equity	10,641	10,044
Total liabilities and member's equity	$ 24,502	$ 23,736

(a) PHI's consolidated total assets include $18 million at both September 30, 2021 and December 31, 2020 of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI's consolidated total liabilities include $10 million and $26 million at September 30, 2021 and December 31, 2020, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 17 — Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021		
(In millions)	Membership Interest	Undistributed (Losses)/Earnings	Total Member's Equity
Balance, December 31, 2020	$ 10,112	$ (68)	$ 10,044
Net income	—	128	128
Distributions to member	—	(81)	(81)
Contributions from member	560	—	560
Balance, March 31, 2021	$ 10,672	$ (21)	$ 10,651
Net income	—	141	141
Distributions to member	—	(333)	(333)
Balance, June 30, 2021	$ 10,672	$ (213)	$ 10,459
Net income	—	266	266
Distributions to member	—	(191)	(191)
Contributions from member	107	—	107
Balance, September 30, 2021	$ 10,779	$ (138)	$ 10,641

	Nine Months Ended September 30, 2020		
(In millions)	Membership Interest	Undistributed (Losses)/Earnings	Total Member's Equity
Balance, December 31, 2019	$ 9,618	$ (10)	$ 9,608
Net income	—	108	108
Distributions to member	—	(134)	(134)
Contributions from member	144	—	144
Balance, March 31, 2020	$ 9,762	$ (36)	$ 9,726
Net income	—	94	94
Distributions to member	—	(134)	(134)
Contributions from member	215	—	215
Balance, June 30, 2020	$ 9,977	$ (76)	$ 9,901
Net income	—	216	216
Distributions to member	—	(183)	(183)
Contribution from member	135	—	135
Balance, September 30, 2020	$ 10,112	$ (43)	$ 10,069

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Electric operating revenues	$ 649	$ 590	$ 1,678	$ 1,624
Revenues from alternative revenue programs	9	18	54	20
Operating revenues from affiliates	2	3	4	6
Total operating revenues	660	611	1,736	1,650
Operating expenses				
Purchased power	103	83	271	248
Purchased power from affiliate	69	80	200	219
Operating and maintenance	68	57	186	184
Operating and maintenance from affiliates	52	49	155	152
Depreciation and amortization	104	96	302	282
Taxes other than income taxes	105	100	282	279
Total operating expenses	501	465	1,396	1,364
Operating income	159	146	340	286
Other income and (deductions)				
Interest expense, net	(35)	(35)	(104)	(103)
Other, net	12	10	37	28
Total other income and (deductions)	(23)	(25)	(67)	(75)
Income before income taxes	136	121	273	211
Income taxes	6	3	9	(16)
Net income	$ 130	$ 118	$ 264	$ 227
Comprehensive income	$ 130	$ 118	$ 264	$ 227

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	2020
Cash flows from operating activities		
Net income	$ 264	$ 227
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	302	282
Deferred income taxes and amortization of investment tax credits	12	(36)
Other non-cash operating activities	(54)	6
Changes in assets and liabilities:		
Accounts receivable	(57)	(61)
Receivables from and payables to affiliates, net	(2)	(23)
Inventories	(6)	2
Accounts payable and accrued expenses	14	36
Income taxes	(10)	(11)
Pension and non-pension postretirement benefit contributions	(9)	(8)
Other assets and liabilities	(114)	15
Net cash flows provided by operating activities	340	429
Cash flows from investing activities		
Capital expenditures	(641)	(512)
Changes in PHI intercompany money pool	—	(117)
Other investing activities	(2)	(3)
Net cash flows used in investing activities	(643)	(632)
Cash flows from financing activities		
Changes in short-term borrowings	5	(82)
Issuance of long-term debt	275	300
Retirement of long-term debt	(1)	(2)
Dividends paid on common stock	(221)	(174)
Contributions from parent	244	262
Other financing activities	(4)	(6)
Net cash flows provided by financing activities	298	298
(Decrease) increase in cash, restricted cash, and cash equivalents	(5)	95
Cash, restricted cash, and cash equivalents at beginning of period	65	63
Cash, restricted cash, and cash equivalents at end of period	$ 60	$ 158
Supplemental cash flow information		
Decrease in capital expenditures not paid	$ (16)	$ (23)

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	19	$	30
Restricted cash and cash equivalents		41		35
Accounts receivable				
Customer accounts receivable	306		279	
Customer allowance for credit losses	(41)		(32)	
Customer accounts receivable, net		265		247
Other accounts receivable	166		131	
Other allowance for credit losses	(17)		(13)	
Other accounts receivable, net		149		118
Receivables from affiliates		—		2
Inventories, net		117		111
Regulatory assets		215		214
Other		12		13
Total current assets		818		770
Property, plant, and equipment (net of accumulated depreciation and amortization of $3,831 and $3,697 as of September 30, 2021 and December 31, 2020, respectively)		7,919		7,456
Deferred debits and other assets				
Regulatory assets		548		570
Investments		120		115
Prepaid pension asset		280		284
Other		63		69
Total deferred debits and other assets		1,011		1,038
Total assets	$	9,748	$	9,264

POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 40	$ 35
Long-term debt due within one year	313	3
Accounts payable	218	226
Accrued expenses	149	164
Payables to affiliates	51	55
Customer deposits	37	51
Regulatory liabilities	27	46
Merger related obligation	29	33
Current portion of DC PLUG obligation	30	30
Other	22	31
Total current liabilities	916	674
Long-term debt	3,128	3,162
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,289	1,189
Asset retirement obligations	45	39
Non-pension postretirement benefit obligations	5	13
Regulatory liabilities	555	644
Other	320	340
Total deferred credits and other liabilities	2,214	2,225
Total liabilities	6,258	6,061
Commitments and contingencies		
Shareholder's equity		
Common stock	2,302	2,058
Retained earnings	1,188	1,145
Total shareholder's equity	3,490	3,203
Total liabilities and shareholder's equity	$ 9,748	$ 9,264

See the Combined Notes to Consolidated Financial Statements

POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	$ 2,058	$ 1,145	$ 3,203
Net income	—	59	59
Common stock dividends	—	(28)	(28)
Contributions from parent	138	—	138
Balance, March 31, 2021	$ 2,196	$ 1,176	$ 3,372
Net income	—	75	75
Common stock dividends	—	(95)	(95)
Balance, June 30, 2021	$ 2,196	$ 1,156	$ 3,352
Net income	—	130	130
Common stock dividends	—	(98)	(98)
Contributions from parent	106	—	106
Balance, September 30, 2021	$ 2,302	$ 1,188	$ 3,490

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 1,796	$ 1,111	$ 2,907
Net income	—	52	52
Common stock dividends	—	(28)	(28)
Contributions from parent	137	—	137
Balance, March 31, 2020	$ 1,933	$ 1,135	$ 3,068
Net income	—	57	57
Common stock dividends	—	(73)	(73)
Balance, June 30, 2020	$ 1,933	$ 1,119	$ 3,052
Net income	—	118	118
Common stock dividends	—	(73)	(73)
Contributions from parent	125	—	125
Balance, September 30, 2020	$ 2,058	$ 1,164	$ 3,222

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Operating revenues				
Electric operating revenues	$ 337	$ 303	$ 899	$ 846
Natural gas operating revenues	23	23	118	116
Revenues from alternative revenue programs	(2)	8	17	(15)
Operating revenues from affiliates	2	3	6	7
Total operating revenues	360	337	1,040	954
Operating expenses				
Purchased power	103	103	289	270
Purchased fuel	9	7	50	49
Purchased power from affiliates	26	21	63	60
Operating and maintenance	47	64	132	160
Operating and maintenance from affiliates	40	37	117	112
Depreciation and amortization	53	48	157	143
Taxes other than income taxes	17	16	50	49
Total operating expenses	295	296	858	843
Operating income	65	41	182	111
Other income and (deductions)				
Interest expense, net	(15)	(15)	(47)	(47)
Other, net	3	2	9	7
Total other income and (deductions)	(12)	(13)	(38)	(40)
Income (loss) before income taxes	53	28	144	71
Income taxes	3	1	9	(20)
Net income	$ 50	$ 27	$ 135	$ 91
Comprehensive income	$ 50	$ 27	$ 135	$ 91

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net income	$ 135	$ 91
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	157	143
Deferred income taxes and amortization of investment tax credits	5	(20)
Other non-cash operating activities	(2)	47
Changes in assets and liabilities:		
Accounts receivable	26	3
Receivables from and payables to affiliates, net	(12)	(5)
Inventories	(5)	(3)
Accounts payable and accrued expenses	17	21
Income taxes	19	(12)
Pension and non-pension postretirement benefit contributions	(1)	(1)
Other assets and liabilities	(7)	(25)
Net cash flows provided by operating activities	332	239
Cash flows from investing activities		
Capital expenditures	(320)	(278)
Other investing activities	1	(3)
Net cash flows used in investing activities	(319)	(281)
Cash flows from financing activities		
Changes in short-term borrowings	(124)	(56)
Issuance of long-term debt	125	178
Retirement of long-term debt	—	(79)
Dividends paid on common stock	(106)	(99)
Contributions from parent	120	112
Other financing activities	(4)	(1)
Net cash flows provided by financing activities	11	55
Increase in cash, restricted cash, and cash equivalents	24	13
Cash, restricted cash, and cash equivalents at beginning of period	15	13
Cash, restricted cash, and cash equivalents at end of period	$ 39	$ 26
Supplemental cash flow information		
(Decrease) increase in capital expenditures not paid	$ (24)	$ 8

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	13	$	15
Restricted cash and cash equivalents		26		—
Accounts receivable				
Customer accounts receivable	135		176	
Customer allowance for credit losses	(18)		(22)	
Customer accounts receivable, net		117		154
Other accounts receivable	59		68	
Other allowance for credit losses	(8)		(9)	
Other accounts receivable, net		51		59
Receivables from affiliates		1		1
Inventories, net				
Fossil fuel		10		6
Materials and supplies		52		51
Prepaid utility taxes		16		11
Regulatory assets		72		58
Renewable energy credits		3		10
Other		4		3
Total current assets		365		368
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,608 and $1,533 as of September 30, 2021 and December 31, 2020, respectively)		4,485		4,314
Deferred debits and other assets				
Regulatory assets		219		222
Goodwill		8		8
Prepaid pension asset		158		162
Other		60		66
Total deferred debits and other assets		445		458
Total assets	$	5,295	$	5,140

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 22	$ 146
Long-term debt due within one year	83	82
Accounts payable	107	126
Accrued expenses	61	46
Payables to affiliates	24	36
Customer deposits	27	32
Regulatory liabilities	49	47
Other	41	20
Total current liabilities	414	535
Long-term debt	1,725	1,595
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	761	715
Asset retirement obligations	16	14
Non-pension postretirement benefits obligations	12	15
Regulatory liabilities	446	493
Other	95	97
Total deferred credits and other liabilities	1,330	1,334
Total liabilities	3,469	3,464
Commitments and contingencies		
Shareholder's equity		
Common stock	1,209	1,089
Retained earnings	617	587
Total shareholder's equity	1,826	1,676
Total liabilities and shareholder's equity	$ 5,295	$ 5,140

See the Combined Notes to Consolidated Financial Statements

DELMARVA POWER & LIGHT COMPANY
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2020	$ 1,089	$ 587	$ 1,676
Net income	—	56	56
Common stock dividends	—	(40)	(40)
Contributions from parent	120	—	120
Balance, March 31, 2021	$ 1,209	$ 603	$ 1,812
Net income	—	30	30
Common stock dividends	—	(23)	(23)
Balance, June 30, 2021	$ 1,209	$ 610	$ 1,819
Net income	—	50	50
Common stock dividends	—	(43)	(43)
Balance, September 30, 2021	$ 1,209	$ 617	$ 1,826

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 977	$ 603	$ 1,580
Net income	—	45	45
Common stock dividends	—	(52)	(52)
Contributions from parent	6	—	6
Balance, March 31, 2020	$ 983	$ 596	$ 1,579
Net income	—	19	19
Common stock dividends	—	(14)	(14)
Contributions from parent	100	—	100
Balance, June 30, 2020	$ 1,083	$ 601	$ 1,684
Net income	—	27	27
Common stock dividends	—	(33)	(33)
Contributions from parent	6	—	6
Balance, September 30, 2020	$ 1,089	$ 595	$ 1,684

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2021	2020	2021	2020
Operating revenues				
Electric operating revenues	$ 450	$ 414	$ 1,055	$ 969
Revenues from alternative revenue programs	—	5	23	(20)
Operating revenues from affiliates	1	1	2	3
Total operating revenues	451	420	1,080	952
Operating expenses				
Purchased power	225	207	527	460
Purchased power from affiliate	5	4	14	9
Operating and maintenance	46	45	128	140
Operating and maintenance from affiliates	35	32	103	98
Depreciation and amortization	46	48	133	134
Taxes other than income taxes	2	2	6	6
Total operating expenses	359	338	911	847
Gain on sales of assets	—	—	—	2
Operating income	92	82	169	107
Other income and (deductions)				
Interest expense, net	(14)	(15)	(43)	(45)
Other, net	1	1	3	5
Total other income and (deductions)	(13)	(14)	(40)	(40)
Income before income taxes	79	68	129	67
Income taxes	(11)	(7)	(12)	(39)
Net income	$ 90	$ 75	$ 141	$ 106
Comprehensive income	$ 90	$ 75	$ 141	$ 106

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Cash flows from operating activities		
Net income	$ 141	$ 106
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	133	134
Deferred income taxes and amortization of investment tax credits	(20)	(40)
Other non-cash operating activities	(8)	34
Changes in assets and liabilities:		
Accounts receivable	(81)	(62)
Receivables from and payables to affiliates, net	—	2
Inventories	(1)	—
Accounts payable and accrued expenses	(3)	16
Income taxes	10	4
Pension and non-pension postretirement benefit contributions	(3)	(3)
Other assets and liabilities	15	(53)
Net cash flows provided by operating activities	183	138
Cash flows from investing activities		
Capital expenditures	(336)	(281)
Other investing activities	1	5
Net cash flows used in investing activities	(335)	(276)
Cash flows from financing activities		
Changes in short-term borrowings	38	(70)
Issuance of long-term debt	350	123
Retirement of long-term debt	(254)	(38)
Changes in PHI intercompany money pool	—	117
Dividends paid on common stock	(280)	(111)
Contributions from parent	303	117
Other financing activities	(5)	(1)
Net cash flows provided by financing activities	152	137
Decrease in cash, restricted cash, and cash equivalents	—	(1)
Cash, restricted cash, and cash equivalents at beginning of period	30	28
Cash, restricted cash, and cash equivalents at end of period	$ 30	$ 27
Supplemental cash flow information		
(Decrease) increase in capital expenditures not paid	$ (34)	$ 9

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021		December 31, 2020	
ASSETS				
Current assets				
Cash and cash equivalents	$	16	$	17
Restricted cash and cash equivalents		5		3
Accounts receivable				
Customer accounts receivable	230		156	
Customer allowance for credit losses	(46)		(32)	
Customer accounts receivable, net		184		124
Other accounts receivable	75		72	
Other allowance for credit losses	(15)		(11)	
Other accounts receivable, net		60		61
Receivables from affiliates		1		6
Inventories, net		38		37
Prepaid utility taxes		10		—
Regulatory assets		57		75
Other		5		3
Total current assets		376		326
Property, plant, and equipment (net of accumulated depreciation and amortization of $1,390 and $1,303 as of September 30, 2021 and December 31, 2020, respectively)		3,649		3,475
Deferred debits and other assets				
Regulatory assets		428		395
Prepaid pension asset		31		40
Other		48		50
Total deferred debits and other assets		507		485
Total assets[(a)]	$	4,532	$	4,286

See the Combined Notes to Consolidated Financial Statements

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2021	December 31, 2020
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 225	$ 187
Long-term debt due within one year	8	261
Accounts payable	146	177
Accrued expenses	43	46
Payables to affiliates	26	31
Customer deposits	19	23
Regulatory liabilities	46	44
Other	15	11
Total current liabilities	528	780
Long-term debt	1,502	1,152
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	671	624
Non-pension postretirement benefit obligations	13	17
Regulatory liabilities	211	274
Other	52	48
Total deferred credits and other liabilities	947	963
Total liabilities[a]	2,977	2,895
Commitments and contingencies		
Shareholder's equity		
Common stock	1,574	1,271
Retained (deficit) earnings	(19)	120
Total shareholder's equity	1,555	1,391
Total liabilities and shareholder's equity	$ 4,532	$ 4,286

(a) ACE's consolidated total assets include $14 million and $13 million at September 30, 2021 and December 31, 2020, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE's consolidated total liabilities include $6 million and $21 million at September 30, 2021 and December 31, 2020, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 17 — Variable Interest Entities for additional information.

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Unaudited)

	Nine Months Ended September 30, 2021		
(In millions)	Common Stock	Retained Earnings (Deficit)	Total Shareholder's Equity
Balance, December 31, 2020	$ 1,271	$ 120	$ 1,391
Net income	—	14	14
Common stock dividends	—	(14)	(14)
Contributions from parent	303	—	303
Balance, March 31, 2021	$ 1,574	$ 120	$ 1,694
Net income	—	37	37
Common stock dividends	—	(215)	(215)
Balance, June 30, 2021	$ 1,574	$ (58)	$ 1,516
Net income	—	90	90
Common stock dividends	—	(51)	(51)
Balance, September 30, 2021	$ 1,574	$ (19)	$ 1,555

	Nine Months Ended September 30, 2020		
(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2019	$ 1,154	$ 122	$ 1,276
Net income	—	13	13
Common stock dividends	—	(23)	(23)
Contributions from parent	1	—	1
Balance, March 31, 2020	$ 1,155	$ 112	$ 1,267
Net income	—	18	18
Common stock dividends	—	(12)	(12)
Contributions from parent	115	—	115
Balance, June 30, 2020	$ 1,270	$ 118	$ 1,388
Net income	—	75	75
Common stock dividends	—	(76)	(76)
Contributions from parent	1	—	1
Balance, September 30, 2020	$ 1,271	$ 117	$ 1,388

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

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

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy, and other energy-related products and services.	Five reportable segments: Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions
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 quarterly 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.

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, accounting, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. 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" in the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

The accompanying consolidated financial statements as of September 30, 2021 and for the three and nine months ended September 30, 2021 and 2020 are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2020 Consolidated Balance Sheets were derived from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2021. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

2. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

CENG Put Option (Exelon and Generation)

Prior to August 6, 2021, Generation owned a 50.01% membership interest in CENG, a joint venture with EDF, which wholly owns the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to an 82% undivided ownership interest in Nine Mile Point Unit 2. CENG is 100% consolidated in Exelon's and Generation's financial statements. See Note 17 — Variable Interest Entities for additional information.

On April 1, 2014, Generation and EDF entered into various agreements including a NOSA, an amended LLC Operating Agreement, an Employee Matters Agreement, and a Put Option Agreement, among others. Under the amended LLC Operating Agreement, CENG made a $400 million special distribution to EDF and committed to make preferred distributions to Generation until Generation has received aggregate distributions of $400 million plus a return of 8.50% per annum.

Under the terms of the Put Option Agreement, EDF had the option to sell its 49.99% equity interest in CENG to Generation exercisable beginning on January 1, 2016 and thereafter until June 30, 2022.

On November 20, 2019, Generation received notice of EDF's intention to exercise the put option to sell its interest in CENG to Generation, and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. The transaction required approval by FERC and the NYPSC, which approvals were received on July 30, 2020 and April 15, 2021, respectively. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF's share of the balance of the preferred distribution payable by CENG to Generation. The difference between the net purchase price and EDF's Noncontrolling Interest as of August 6, 2021 was recorded in Common Stock in Exelon's Consolidated Balance Sheet and Membership Interest in Generation's Consolidated Balance Sheet. As a result of the transaction, Exelon and Generation recorded deferred tax liabilities of $290 million and $288 million, respectively, in Common Stock in Exelon's Consolidated Balance Sheet and Membership Interest in Generation's Consolidated Balance Sheet. See Note 10 — Income Taxes for additional information.

The following tables summarize the effects of the changes in Generation's ownership interest in CENG in Exelon's Shareholders' Equity and Generation's Member's Equity:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Net income attributable to Exelon's common shareholders	$ 1,203	$ 1,315
Pre-tax increase in Exelon's common stock for purchase of EDF's 49.99% equity interest[(a)]	1,080	1,080
Decrease in Exelon's common stock due to deferred tax liabilities resulting from purchase of EDF's 49.99% equity interest[(a)]	(290)	(290)
Change from net income attributable to common stock and transfers from noncontrolling interest	$ 1,993	$ 2,105

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

(a) Represents non-cash activity in Exelon's and Generation's consolidated financial statements.

Agreement for Sale of Generation's Solar Business (Exelon and Generation)

On December 8, 2020, Generation entered into an agreement with an affiliate of Brookfield Renewable, for the sale of a significant portion of Generation's solar business, including 360 MW of generation in operation or under construction across more than 600 sites across the United States. Generation will retain certain solar assets not included in this agreement, primarily Antelope Valley.

Completion of the transaction contemplated by the sale agreement was subject to the satisfaction of several closing conditions which were satisfied in the first quarter of 2021. The sale was completed on March 31, 2021 for a purchase price of $810 million. Generation received cash proceeds of $675 million, net of $125 million long-term debt assumed by the buyer and certain working capital and other post-closing adjustments. Exelon and Generation recognized a pre-tax gain of $68 million which is included in Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on the SolGen nonrecourse debt included as part of the transaction.

Agreement for the Sale of a Generation Biomass Facility (Exelon and Generation)

On April 28, 2021, Generation and ReGenerate Energy Holdings, LLC ("ReGenerate") entered into a purchase agreement, under which ReGenerate agreed to purchase Generation's interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, Exelon and Generation recorded a pre-tax impairment charge of $140 million in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Completion of the transaction was subject to the satisfaction of various customary closing conditions which were satisfied in the second quarter of 2021. The sale was completed on June 30, 2021 for a net purchase price of $36 million.

3. Regulatory Matters (All Registrants)

As discussed in Note 3 — Regulatory Matters of the Exelon 2020 Form 10-K, the Registrants are involved in rate and regulatory proceedings at FERC and their state commissions. The following discusses developments in 2021 and updates to the 2020 Form 10-K.

Utility Regulatory Matters (Exelon, PHI, and the Utility Registrants)

Distribution Base Rate Case Proceedings

The following tables show the completed and pending distribution base rate case proceedings in 2021.

Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois[(a)]	April 16, 2020	Electric	$ (11)	$ (14)	8.38 %	December 9, 2020	January 1, 2021
PECO - Pennsylvania	September 30, 2020	Natural Gas	69	29	10.24 %	June 22, 2021	July 1, 2021
BGE - Maryland[(b)]	May 15, 2020 (amended September 11, 2020)	Electric	203	140	9.50 %	December 16, 2020	January 1, 2021
		Natural Gas	108	74	9.65 %		
Pepco - District of Columbia[(c)]	May 30, 2019 (amended June 1, 2020)	Electric	136	109	9.275 %	June 8, 2021	July 1, 2021
Pepco - Maryland[(d)]	October 26, 2020 (amended March 31, 2021)	Electric	104	52	9.55 %	June 28, 2021	June 28, 2021
DPL - Delaware	March 6, 2020 (amended February 2, 2021)	Electric	23	14	9.60 %	September 15, 2021	October 6, 2020
ACE - New Jersey[(e)]	December 9, 2020 (amended February 26, 2021)	Electric	67	41	9.60 %	July 14, 2021	January 1, 2022

(a) ComEd's 2021 approved revenue requirement reflects an increase of $50 million for the initial year revenue requirement for 2021 and a decrease of $64 million related to the annual reconciliation for 2019. The revenue requirement for 2021 and the revenue requirement for 2019 provide for a weighted average debt and equity return on distribution rate base of 6.28%, inclusive of an allowed ROE of 8.38%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points.

(b) Reflects a three-year cumulative multi-year plan for 2021 through 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. BGE proposed to use certain tax benefits to fully offset the increases in 2021 and 2022 and partially offset the increase in 2023. However, the MDPSC only utilized the tax benefits to fully offset the increases in 2021 such that customer rates will remain unchanged from 2020 to 2021. The MDPSC has deferred a decision on whether to use certain tax benefits to offset the customer rate increases in 2022 and 2023 and BGE cannot predict the outcome.

(c) Reflects a cumulative multi-year plan with 18-months remaining in 2021 through 2022. The DCPSC awarded Pepco electric incremental revenue requirement increases of $42 million and $67 million, before offsets, for the remainder of 2021 and 2022, respectively. However, the DCPSC utilized the acceleration of refunds for certain tax benefits along with other rate relief to partially offset the customer rate increases by $22 million and $40 million for the remainder of 2021 and 2022, respectively.

(d) 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. The MDPSC has deferred decision on whether to use additional tax benefits to offset customer rate increases for periods after March 31, 2022 and Pepco cannot predict the outcome.

(e) Requested and approved increases are before New Jersey sales and use tax. The order allows ACE to retain approximately $11 million of certain tax benefits which resulted in a decrease to income tax expense in Exelon's, PHI's, and ACE's Consolidated Statements of Operations and Comprehensive Income in the third quarter of 2021.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois[a]	April 16, 2021	Electric	$ 51	7.36 %	Fourth quarter of 2021
PECO - Pennsylvania[b]	March 30, 2021	Electric	246	10.95 %	Fourth quarter of 2021
DPL - Maryland	September 1, 2021	Electric	29	10.10 %	First quarter of 2022

(a) ComEd's 2022 requested revenue requirement reflects an increase of $40 million for the initial year revenue requirement for 2022 and an increase of $11 million related to the annual reconciliation for 2020. The revenue requirement for 2022 provides for a weighted average debt and equity return on distribution rate base of 5.72%, inclusive of an allowed ROE of 7.36%, reflecting the average monthly yields for 30-year treasury bonds plus 580 basis points. The reconciliation revenue requirement for 2020 provides for a weighted average debt and equity return on distribution rate base of 5.69%, inclusive of an allowed ROE of 7.29%, reflecting the average monthly yields for 30-year treasury bonds plus 580 basis points less a performance metrics penalty of 7 basis points.

(b) The Joint Petition for Settlement was filed on September 15, 2021 and recommended for approval by the administrative law judge on October 6, 2021. PAPUC approval is expected in the fourth quarter of 2021.

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 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 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 update for PECO, BGE, Pepco, DPL, and ACE also reconciles any differences between the actual costs and actual revenues for the calendar year (annual reconciliation).

For 2021, the following total increases/(decreases) were included in the Utility Registrants’ electric transmission formula rate updates:

Registrant[a]	Initial Revenue Requirement Increase (Decrease)	Annual Reconciliation Increase	Total Revenue Requirement Increase[b]	Allowed Return on Rate Base[c]	Allowed ROE[d]
ComEd	$ 33	$ 12	$ 45	8.20 %	11.50 %
PECO	(2)	26	24	7.37 %	10.35 %
BGE	38	27	65	7.35 %	10.50 %
Pepco	(9)	21	12	7.68 %	10.50 %
DPL	19	33	52	7.20 %	10.50 %
ACE	27	24	51	7.45 %	10.50 %

(a) All rates are effective June 1, 2021 - May 31, 2022, subject to review by interested parties pursuant to review protocols of each Utility Registrants' tariff.

(b) In 2020, ComEd, BGE, Pepco, DPL, and ACE's transmission revenue requirement included a one-time decrease in accordance with the April 24, 2020 settlement agreement related to excess deferred income taxes which now completed has resulted in an increase to the 2021 transmission revenue requirement. In 2020, PECO's transmission revenue requirement included a one-time decrease in accordance with the December 5, 2019 settlement agreement related to refunds which now completed has resulted in an increase to the 2021 transmission revenue requirement.

(c) Represents the weighted average debt and equity return on transmission rate bases.

(d) As part of the FERC-approved settlements of ComEd’s 2007 and PECO's 2017 rate cases, the rate of return on common equity is 11.50% and 10.35%, respectively, inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55% and 55.75%, respectively. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL, and ACE, the rate of return on common equity is 10.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO.

Other State Regulatory Matters

Illinois Regulatory Matters

Clean Energy Law (Exelon and ComEd). On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law includes, among other features, (1) procurement of carbon mitigation credits (CMCs) from qualifying nuclear-powered generating facilities, (2) a requirement to file a general rate case or a new four-year multi-year plan no later than January 20, 2023 to establish rates effective after ComEd's existing performance-based distribution formula rate sunsets, (3) an extension of and certain adjustments to ComEd's energy efficiency MWh savings goals, (4) revisions to the Illinois RPS requirements, including expanded charges for the procurement of RECs from wind and solar generation, (5) a requirement to accelerate amortization of ComEd's unprotected excess deferred income taxes that ComEd was previously directed by the ICC to amortize using the average rate assumption method which equates to approximately 39.5 years, and (6) requirements that the ICC initiate and conduct various regulatory proceedings on subjects including ethics, spending, grid investments, and performance metrics. Regulatory or legal challenges regarding the validity or implementation of the Clean Energy Law are possible and Exelon, Generation, and ComEd cannot reasonably predict the outcome of any such challenges.

Carbon Mitigation Credit

The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois will be eligible to participate in the CMC procurement process and, if awarded contracts, would be committed to operate through May 31, 2027. Selected generators will by December 3, 2021 contract directly with ComEd for the procurement of the CMCs based upon the number of MWhs produced annually by the eligible facilities, subject to specified caps and minimum performance requirements. The price to be paid for each CMC will be determined through a competitive bidding process that includes consumer-protection measures that cap 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 the new law will result in net payments to ComEd ratepayers if the energy index, the capacity price and applicable federal tax credits or subsidy exceed the maximum bid cap.

ComEd is required to purchase CMCs from eligible nuclear facilities and all its costs of doing so will be recovered through a new rider. That rider will provide for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase CMCs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods.

See Note 7 – Early Plant Retirements for the impacts of the provisions above on the Illinois nuclear plants and Generation's consolidated financial statements. The provisions do not impact ComEd's consolidated financial statements until 2022.

ComEd Electric Distribution Rates

The Clean Energy Law contains requirements associated with ComEd's transition away from the performance-based electric distribution formula rate. The law authorizing that rate setting process sunsets at the end of 2022. The Clean Energy Law, and tariffs adopted under it, governs both the remaining reconciliations of rates set under that formula process and requires ComEd to file in 2023 its choice of either a general rate case or a four-year multi-year plan to set rates that take effect in 2024.

If ComEd elects to file a multi-year plan, that plan would set rates for 2024 – 2027, based on forecasted revenue requirements and an ICC determined rate of return on rate base, including the cost of common equity. Each year of the multi-year plan is subject to after the fact ICC review and reconciliation of the plan's revenue requirement for that year with the actual costs that the ICC determines are prudently and reasonably incurred for that year.

That reconciliation is subject to adjustment for certain uncontrollable expenses and, unless the plan is modified, to a 5% cap on increases over the previously approved multi-year rate plan revenue requirement. ComEd would make its initial reconciliation filing in 2025, and 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. The ICC must also approve certain annual performance metrics, which can impose symmetrical performance adjustments in the total range of 20 to 60 basis points to ComEd's rate of return on common equity based on the extent to which ComEd achieved the annual performance goals. ComEd will recover from retail customers, subject to certain exceptions, the costs it incurs pursuant to the Clean Energy Law either through its electric distribution rate or other recovery mechanisms.

The Clean Energy Law, among other things, also requires ComEd's rates to include a decoupling mechanism to eliminate any impacts of weather or load from ComEd's electric distribution rate revenues. The Clean Energy Law also requires the ICC to initiate a docket to accelerate and fully credit to customers unprotected property related TCJA excess deferred income taxes no later than December 31, 2025.

Energy Efficiency

The Clean Energy Law 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 2022 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). ComEd filed its annual energy efficiency formula rate update with the ICC on June 1, 2021. The filing establishes the revenue requirement used to set the rates that will take effect in January 2022 after the ICC's review and approval. The requested revenue requirement update is based on a reconciliation of the 2020 actual costs plus projected 2022 expenditures.

Initial Revenue Requirement Increase	Annual Reconciliation Decrease	Total Revenue Requirement Increase	Requested Return on Rate Base[a]	Requested ROE
$ 55	$ (1)	$ 54	5.72 %	7.36 %

(a) The requested revenue requirement increase provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 5.72% inclusive of an allowed ROE of 7.36%, reflecting the monthly average yields for 30-year treasury bonds plus 580 basis points. For the 2020 reconciliation year, the requested revenue requirement provides for a weighted average debt and equity return on the energy efficiency regulatory asset and rate base of 6.26% inclusive of an allowed ROE of 8.46%, 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.

Maryland Regulatory Matters

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.

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 will record 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.

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.

Regulatory Assets and Liabilities

The Utility Registrants' regulatory assets and liabilities have not changed materially since December 31, 2020, unless noted below. See Note 3 — Regulatory Matters of the Exelon 2020 Form 10-K for additional information on the specific regulatory assets and liabilities.

ComEd. Regulatory assets increased $93 million primarily due to an increase of $47 million in the Electric Distribution Formula Rate Annual Reconciliations regulatory asset and $127 million in the Energy Efficiency Costs regulatory asset, partially offset by a decrease of $87 million in the renewable energy regulatory asset.

PECO. Regulatory assets increased $135 million primarily due to an increase of $123 million in the Deferred Income Taxes regulatory asset and $14 million in the Vacation Accrual regulatory asset. Regulatory liabilities increased by $66 million primarily due to an increase of $71 million in the Nuclear Decommissioning regulatory liability partially offset by a $18 million decrease in the Electric Energy and Natural Gas Costs regulatory liability.

BGE. Regulatory liabilities decreased $116 million primarily due to a decrease of $128 million in the Deferred Income Taxes regulatory liability offset by an increase of $12 million in Other regulatory liabilities.

Pepco. Regulatory liabilities decreased $108 million primarily due to a decrease of $89 million in the Deferred Income Taxes regulatory liability and $19 million in the Transmission Formula Rate regulatory liability.

DPL. Regulatory liabilities decreased $45 million primarily due to a decrease of $41 million in the Deferred Income Taxes regulatory liability.

ACE. Regulatory liabilities decreased $61 million primarily due to a decrease of $67 million in the Deferred Income Taxes regulatory liability partially offset by an increase of $14 million in the Stranded Costs regulatory liability.

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 Exelon's and the Utility Registrant's 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.

	Exelon	ComEd(a)	PECO	BGE(b)	PHI	Pepco(c)	DPL(c)	ACE
September 30, 2021	$ 44	$ —	$ —	$ 39	$ 5	$ 3	$ 2	$ —
December 31, 2020	51	(1)	—	45	7	4	3	—

(a) Reflects ComEd's unrecognized equity returns/(losses) earned/(incurred) for ratemaking purposes on its electric distribution formula rate regulatory assets.

(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs.

(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. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

Generation Regulatory Matters (Exelon and Generation)

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation’s Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. In response to the high demand and significantly reduced total generation on the system, the PUCT directed ERCOT to use an administrative price cap of $9,000 per MWh during firm load shedding events.

The estimated impact to Exelon’s and Generation’s Net income for the nine months ended September 30, 2021 arising from these market and weather conditions was a reduction of approximately $880 million. The estimated impact to Exelon's and Generation's Net income for the three months ended September 30, 2021 was not material. The ultimate impact to Exelon’s and Generation’s consolidated financial statements for the full year 2021 may be affected by a number of factors, including the impacts of customer and counterparty credit losses, any state or federal solutions to address the financial challenges caused by the event, and related litigation and contract disputes.

During February and March 2021, various parties with differing interests, including generators and retail providers, filed requests with the PUCT to void the PUCT’s orders setting prices at $9,000 per MWh during firm load shedding events. Other requests were made for the PUCT to enforce its order and reduce prices for 33 hours between February 18 and February 19 after firm load shedding ceased, and to cap ancillary services at $9,000 per MWh. On March 2, 2021, a third party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT’s actions. Generation intervened in that appeal and filed its initial brief on June 2, 2021. On April 19, 2021, Generation filed a declaratory action and request for judicial review of the PUCT’s orders setting prices at $9,000 per MWh in District Court of Travis County, Texas. Generation subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third party proceeding. On May 17, 2021, Generation amended its petition for declaratory action and request for judicial review pending in the District Court of Travis County, Texas. Exelon and Generation cannot predict the outcome of these proceedings or the financial statement impact.

Due to these events, a number of ERCOT market participants experienced bankruptcies or defaulted on payments to ERCOT, resulting in approximately a $3.0 billion payment shortfall in collections, which is allocated to the remaining ERCOT market participants. As of September 30, 2021, Generation has recorded its estimated portion of this obligation of approximately $17 million on a discounted basis, which is to be paid over a term of 83 years. ERCOT rules historically have limited recovery of default from market participants to $2.5 million per month market-wide. In February 2021, the PUCT gave ERCOT discretion to disregard those rules, but ERCOT has declined to exercise that discretion thus far. On March 8, 2021, a third party filed a notice of appeal in the Court of Appeals for the Third District of Texas challenging the validity of the PUCT's order to ERCOT in February 2021. Generation intervened in that appeal and filed its initial brief on July 7, 2021. On May 7, 2021, Generation filed a declaratory action and request for judicial review of the PUCT's order in the District Court of Travis County, Texas. Generation subsequently requested that the District Court of Travis County, Texas stay its proceeding pending action by the Court of Appeals in the third party proceeding. Exelon and Generation cannot predict the outcome of these proceedings or the financial statement impact.

Additionally, several legislative proposals were introduced in the Texas legislature during February and March 2021 concerning the amount, timing and allocation of recovery of the $3.0 billion shortfall, as well as recovery of other costs associated with the PUCT's directive to set prices at $9,000 per MWh. Two of these proposals were enacted into law in June 2021 and establish financing mechanisms that ERCOT and certain market participants can utilize to fund amounts owed to ERCOT. Generation participated in proceedings before the PUCT addressing the proposed allocation of the $2.1 billion in securitized funds for reliability and ancillary service charges over $9,000/MWh. In September 2021, Generation entered into a settlement agreement and stipulation to resolve the allocation issues. The PUCT approved the settlement agreement and stipulation on October 13, 2021.

In addition, other legislative proposals were introduced in the Texas legislature during February and March 2021 addressing cold-weather preparation for power plants and natural gas production and transportation infrastructure and the market structure for reliability services. The Texas legislature addressed these proposals by enacting a bill with a broad set of market reforms that, among other things, directed the PUCT to establish weatherization standards for electric generators within six months of enactment and gave the PUCT authority to impose administrative penalties if the new proposed standards, once adopted, are not met. On October 21, 2021, the PUCT adopted rule change requiring generators by December 1, 2021 to complete a number of specified winter readiness preparations and to submit to ERCOT a report describing and certifying the completion of those preparations. The PUCT described these requirements as the first phase of its actions with respect to winter preparedness, to be followed by a second phase consisting of a year-round set of weather preparedness standards to be informed by a weather study that is being conducted by ERCOT.

The legislation also directs the PUCT to evaluate whether additional ancillary services are needed for reliability in the ERCOT power region to provide adequate incentives for dispatchable generation. Exelon and others have submitted various proposals to the PUCT with respect to a range of potential market reforms, including the implementation of additional ancillary service products as well as changes to the high system-wide offer cap and operating reserve demand curve, which remain pending. On September 23, 2021, the PUCT solicited comments regarding whether it should set ERCOT's high system-wide offer cap at $4,500/MWh if the PUCT takes action to amend its rules with respect to that cap. Exelon and others submitted comments to the PUCT, which remain pending. The PUCT is expected to address potential changes to ERCOT's market rules later in 2021.

In February 2021, more than 70 local distribution companies (LDCs) and natural gas pipelines in multiple states throughout the mid-continent region, where Generation serves natural gas customers, issued operational flow orders (OFOs), curtailments or other limitations on natural gas transportation or use to manage the operational integrity of the applicable LDC or pipeline system. When in effect, gas transportation or use above these limitations is subject to significant penalties according to the applicable LDCs' and natural gas pipelines' tariffs. Gas transportation and supply in many states became restricted due to wells freezing and pipeline compression disruption, while demand was increasing due to the extreme cold temperatures, resulting in extremely high natural gas prices. Due to the extraordinary circumstances, many LDCs and natural gas pipelines have either voluntarily waived or have sought applicable regulatory approvals to waive the tariff penalties associated with the extreme weather event. During March 2021, three natural gas pipelines filed individual petitions with FERC requesting approval to waive OFO penalties. Generation also filed motions in March 2021 to intervene and filed comments in support of these FERC waiver requests. On March 25, 2021, FERC issued an order on one of the petitions approving a pipeline's request for a limited waiver of penalties for February 15, 2021. On April 23, 2021, Generation and several other entities filed a request at FERC for rehearing of this order which was denied on May 24, 2021. Generation and the other entities filed an appeal of the rehearing of the order with the U.S. Court of Appeals for the D.C. Circuit on July 21, 2021. Additionally, Generation and the other entities filed a complaint requesting that FERC expand the order to include additional days of the weather event in February, from February 16 through February 19, 2021. On October 21, 2021, FERC denied the complaint finding that a pipeline has the discretion whether to waive penalties under its tariff. Generation is evaluating whether to seek rehearing and appeal of the FERC order. During April 2021, FERC issued orders on the remaining petitions approving the requests to waive the penalties. During May 2021, an LDC filed a motion with the Kansas Corporation Commission (KCC) requesting the KCC to grant a waiver from the tariff and allow the LDC to reduce the amounts assessed by permitting the removal of a multiplier from the penalty calculation. On October 8, 2021, a settlement was filed with the KCC that, if approved, would resolve this matter. Exelon and Generation cannot predict the outcome of the pending FERC complaint proceeding, the KCC proceeding, or the determinations made by the LDCs and natural gas pipelines.

Illinois Regulatory Matters

Clean Energy Law. See Clean Energy Law above for additional information related to Generation. See Note 7 – Early Plant Retirements for additional information on Generation's Illinois nuclear plants.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, New Jersey enacted legislation that established a ZEC program that provides compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE, will be required to purchase those ZECs. On April 18, 2019, the NJBPU approved the award of ZECs to Salem 1 and Salem 2. Upon approval, Generation began recognizing revenue for the sale of New Jersey ZECs in the month they are generated. On March 19, 2021, a three-judge panel of the Superior Court of New Jersey Appellate Division unanimously affirmed the NJBPU's April 2019 order awarding ZECs for the first eligibility period. On April 8, 2021, New Jersey Rate Counsel filed a notice asking the New Jersey Supreme Court to hear the appeal of the Superior Court's order. On July 9, 2021, the New Jersey Supreme Court declined to hear the appeal. On October 1, 2020, PSEG and Generation filed applications seeking ZECs for the second eligibility period (June 2022 through May 2025). On April 27, 2021, the NJBPU approved the award of ZECs to Salem 1 and Salem 2 for the second eligibility period. On May 11, 2021, the New Jersey Rate Counsel appealed the April 27, 2021 decision to the Superior Court of New Jersey Appellate Division. Briefing on the appeal is expected to conclude in the fourth quarter of 2021 or first quarter of 2022. Exelon and Generation cannot predict the outcome of this proceeding.

New England Regulatory Matters

Mystic Units 8 and 9 and Everett Marine Terminal Cost of Service Agreement. On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire Mystic Units 8 and 9 absent regulatory reforms on June 1, 2022. On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 & 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service compensation, reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the adjacent Everett Marine Terminal acquired by Generation in October 2018. Those adjustments were reflected in a compliance filing made on March 1, 2019. In the December 20, 2018 order, FERC also directed a paper hearing on ROE using a new methodology. On January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings in the order. On July 15, 2021, FERC issued an order establishing the ROE to be used in the cost of service agreement for Mystic 8 and 9 at 9.33%. On August 16, 2021, Exelon and several other parties filed requests for rehearing of certain aspects of the July 15, 2021 order. These requests were denied by operation of law; however, FERC indicated it would address the issues raised in the request in a future order.

On July 17, 2020, FERC issued three orders, which together affirmed the recovery of key elements of Mystic's cost of service compensation, including recovery of costs associated with the operation of the Everett Marine Terminal. FERC directed a downward adjustment to the rate base for Mystic Units 8 and 9, the effect of which will be partially offset by elimination of a crediting mechanism for third party gas sales during the term of the cost of service agreement. In addition, several parties filed protests to a compliance filing by Generation on September 15, 2020, taking issue with how gross plant in-service was calculated, and Generation filed an answer to the protests on October 21, 2020. On December 21, 2020, FERC issued an order on rehearing of the three July 17, 2020 orders, clarifying several cost of service provisions. Several parties appealed the December 21, 2020 order to the U.S. Court of Appeals for the D.C. Circuit and that appeal was consolidated with appeals of orders issued December 20, 2018 and July 17, 2020 in the Mystic proceeding. Briefs in support of their petitions for review were filed by Exelon and several other parties on September 7, 2021. Briefing is expected to conclude in February 2022.

On February 25, 2021, Mystic made its filing to comply with the December 21, 2020 order. On April 26, 2021, FERC rejected Mystic's language and directed another compliance filing relating to the claw back provision language, which only applies if Mystic 8 and 9 were to continue operation after the conclusion of the cost-of-service period. FERC's April 26, 2021 order also accepted in part and rejected in part Mystic's September 15, 2020 compliance filing. It directed a further compliance filing in 60 days consistent with the information provided in Mystic's October 21, 2020 answer to protests, which Mystic filed on June 2, 2021 and FERC accepted on July 29, 2021. On August 16, 2021, Mystic made a compliance filing, reflecting changes to the cost of service agreement to comply with the July 15, 2021 order on ROE.

On August 25, 2020, a group of New England generators filed a complaint against Generation seeking to extend the scope of the claw back provision in the cost-of-service agreement, whereby Generation would refund certain amounts recovered during the term of the cost of service if it returns to market afterwards. On April 15, 2021 FERC dismissed the complaint.

On February 16, 2021, Generation filed an unopposed motion to voluntarily dismiss an appeal filed with the U.S. Court of Appeals for the D.C. Circuit stemming from a June 2020 complaint filed with FERC against ISO-NE over failures to follow its tariff in evaluating Mystic for transmission security for the 2024 to 2025 Capacity Commitment Period, which was granted on February 18, 2021.

See Note 7 — Early Plant Retirements for additional information on the impacts of Generation's August 2020 decision to retire Mystic Units 8 and 9 upon expiration of the cost of service agreement.

Federal Regulatory Matters

PJM and NYISO MOPR Proceedings. PJM and NYISO capacity markets include a MOPR. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a state government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Prior to December 19, 2019, the MOPR in PJM applied only to certain new gas-fired resources. Currently, the MOPR in NYISO applies only to certain resources in downstate New York.

For Generation's nuclear facilities in PJM and NYISO that are currently receiving state-supported compensation for carbon-free attributes, an expanded MOPR would require exclusion of such compensation when bidding into future capacity auctions, resulting in an increased risk of these facilities not receiving capacity revenues in future auctions.

On December 19, 2019, FERC required PJM to broadly apply the MOPR to all new and existing resources including nuclear, renewables, demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. This greatly expanded the breadth and scope of PJM's MOPR, which became effective as of PJM's capacity auction for the 2022-23 planning year. While FERC included some limited exemptions, no exemptions were available to state-supported nuclear resources.

FERC provided no new mechanism for accommodating state-supported resources other than the existing FRR mechanism (under which an entire utility zone would be removed from PJM's capacity auction along with sufficient resources to support the load in such zone). In response to FERC's order, PJM submitted a compliance filing on March 18, 2020 wherein PJM proposed tariff language interpreting and implementing FERC's directives, and proposed a schedule for resuming capacity auctions that is contingent on the timing of FERC's action on the compliance filing.

On April 16, 2020, FERC issued an order largely denying most requests for rehearing of FERC's December 2019 order but granting a few clarifications that required an additional PJM compliance filing which PJM submitted on June 1, 2020.

A number of parties, including Exelon, have filed petitions for review of FERC's orders in this proceeding, which remain pending before the Court of Appeals for the District of Columbia Circuit.

As a result, the MOPR applied in the capacity auction for the 2022-23 planning year to Generation's owned or jointly owned nuclear plants in those states receiving a benefit under the Illinois ZES and the New Jersey ZEC program. The MOPR prevented Quad Cities from clearing in that capacity auction.

At the direction of the PJM Board of Managers, PJM and its stakeholders developed further MOPR reforms to ensure that the capacity market rules respect and accommodate state resource preferences such as the ZEC programs. PJM filed related tariff revisions at FERC on July 30, 2021 and, on September 29, 2021, PJM's proposed MOPR reforms became effective by operation of law. Under the new tariff provisions, the MOPR will no longer apply to any of Generation's owned or jointly owned nuclear plants. A request for rehearing of FERC's notice establishing the effective date for PJM's proposed market reforms was filed on October 5, 2021 and remains pending.

On February 20, 2020, FERC issued an order rejecting requests to expand NYISO's version of the MOPR (referred to as buyer-side mitigation rules) beyond its current limited applicability to certain resources in downstate. However, on October 14, 2020, two natural gas-fired generators in New York filed a complaint at FERC seeking to expand the MOPR in NYISO to apply to all resources, new and existing, across the entire NYISO market. Exelon is strenuously opposing expansion of FERC's MOPR policies in the NYISO market. While it is too early in the proceeding to predict its outcome and there are significant differences between the NYISO and PJM markets that would justify a different result, if FERC applies the MOPR in NYISO broadly as requested in the complaint, Generation's facilities in NYISO that are receiving ZEC compensation may be at increased risk of not clearing the capacity auction.

If Generation's state-supported nuclear plants in PJM or NYISO are subjected to the MOPR or equivalent without compensation under an FRR or similar program, it could have a material adverse impact on Exelon's and Generation's financial statements, which Exelon and Generation cannot reasonably estimate at this time.

Operating License Renewals

Conowingo Hydroelectric Project. On August 29, 2012, Generation submitted an application to FERC for a new license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation's efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act (401 Certification) from MDE for Conowingo, Generation had been working with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 27, 2018, MDE issued its 401 Certification for Conowingo. On October 29, 2019, Generation and MDE filed with FERC a Joint Offer of Settlement (Offer of Settlement) that would resolve all outstanding issues relating to the 401 Certification. Pursuant to the Offer of Settlement, the parties submitted Proposed License Articles to FERC to be incorporated by FERC into the new license in accordance with FERC's discretionary authority under the Federal Power Act.

On March 19, 2021, FERC issued a new 50-year license for Conowingo, effective March 1, 2021. FERC adopted the Proposed License Articles into the new license only making modifications it deemed necessary to allow FERC to enforce the Proposed License Articles. Consistent with the Offer of Settlement, FERC found that MDE waived its 401 Certification. On April 19, 2021, a few environmental groups filed with FERC a petition for rehearing requesting that FERC reconsider the issuance of the new Conowingo license, which was denied by operation of law on May 20, 2021. On June 17, 2021, the petitioners appealed FERC's ruling to the United States Court of Appeals. On July 15, 2021, FERC issued an order addressing the arguments raised on rehearing, affirming the determinations of its March 19, 2021 order. Generation cannot predict the outcome of this proceeding.

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. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and gas tariff sales, distribution, and transmission services.

See Note 4 — Revenue from Contracts with Customers of the Exelon 2020 Form 10-K for additional information regarding the primary sources of revenue for the Registrants.

Contract Balances (All Registrants)

Contract Assets

Generation records contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before Generation has an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. Generation records contract assets and contract receivables in Other current assets and Customer accounts receivable, net, respectively, in Exelon's and Generation's Consolidated Balance Sheets.

The following table provides a rollforward of the contract assets reflected in Exelon's and Generation's Consolidated Balance Sheets for the three and nine months ended September 30, 2021 and 2020. The Utility Registrants do not have any contract assets.

	Exelon	Generation
Balance as of December 31, 2020	$ 144	$ 144
Amounts reclassified to receivables	(16)	(16)
Revenues recognized	13	13
Amounts previously held-for-sale	12	12
Balance as of March 31, 2021	153	153
Amounts reclassified to receivables	(12)	(12)
Revenues recognized	9	9
Balance as of June 30, 2021	150	150
Amounts reclassified to receivables	(15)	(15)
Revenues recognized	14	14
Balance as of September 30, 2021	$ 149	$ 149

	Exelon	Generation
Balance as of December 31, 2019	$ 174	$ 174
Amounts reclassified to receivables	(19)	(19)
Revenues recognized	17	17
Balance as of March 31, 2020	172	172
Amounts reclassified to receivables	(26)	(26)
Revenues recognized	13	13
Balance as of June 30, 2020	159	159
Amounts reclassified to receivables	(18)	(18)
Revenues recognized	19	19
Balance as of September 30, 2020	$ 160	$ 160

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.

For Generation, these contract liabilities primarily relate to upfront consideration received or due for equipment service plans and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation.

For PHI, Pepco, DPL, and ACE these contract liabilities primarily relate to upfront consideration received in the third quarter of 2020 for a collaborative arrangement with an unrelated owner and manager of communication infrastructure. The revenue attributable to this arrangement will be recognized as operating revenue over the 35 years under the collaborative arrangement.

The following table provides a rollforward of the contract liabilities reflected in Exelon's, Generation's, PHI's, Pepco's, DPL's, and ACE's Consolidated Balance Sheets for the three and nine months ended September 30, 2021 and 2020. As of September 30, 2021 and December 31, 2020, ComEd's, PECO's, and BGE's contract liabilities were immaterial.

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	$ 151	$ 84	$ 118	$ 94	$ 12	$ 12
Consideration received or due	20	31	—	—	—	—
Revenues recognized	(27)	(64)	(2)	(2)	—	—
Amounts previously held-for-sale	3	3	—	—	—	—
Balance as of March 31, 2021	147	54	116	92	12	12
Consideration received or due	17	39	—	—	—	—
Revenues recognized	(32)	(68)	(3)	(1)	(1)	(1)
Balance as of June 30, 2021	132	25	113	91	11	11
Consideration received or due	31	93	—	—	—	—
Revenues recognized	(26)	(65)	(2)	(2)	—	—
Balance as of September 30, 2021	$ 137	$ 53	$ 111	$ 89	$ 11	$ 11

	Exelon	Generation	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	$ 33	$ 71	$ —	$ —	$ —	$ —
Consideration received or due	20	55	—	—	—	—
Revenues recognized	(24)	(70)	—	—	—	—
Balance as of March 31, 2020	29	56	—	—	—	—
Consideration received or due	13	34	—	—	—	—
Revenues recognized	(22)	(63)	—	—	—	—
Balance as of June 30, 2020	20	27	—	—	—	—
Consideration received or due	154	94	124	98	13	13
Revenues recognized	(25)	(65)	(2)	(2)	—	—
Balance as of September 30, 2020	$ 149	$ 56	$ 122	$ 96	$ 13	$ 13

The following table reflects revenues recognized in the three and nine months ended September 30, 2021 and 2020, which were included in contract liabilities at December 31, 2020 and 2019, respectively:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Exelon	$ 4	$ 2	$ 38	$ 25
Generation	2	2	81	63
PHI	2	—	7	—
Pepco	2	—	5	—
DPL	—	—	1	—
ACE	—	—	1	—

Transaction Price Allocated to Remaining Performance Obligations (All Registrants)

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of September 30, 2021. 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 Generation's power and gas sales contracts as they contain variable volumes and/or variable pricing. This disclosure also 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.

	2021	2022	2023	2024	2025 and thereafter	Total
Exelon	$ 82	$ 125	$ 50	$ 35	$ 184	$ 476
Generation	168	281	92	41	97	679
PHI	2	8	8	6	87	111
Pepco	2	6	6	5	70	89
DPL	—	1	1	—	9	11
ACE	—	1	1	1	8	11

Revenue Disaggregation (All Registrants)

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 CODM in deciding how to evaluate performance and allocate resources at each of the Registrants.

Exelon has eleven reportable segments, which include Generation's five reportable segments consisting of the Mid-Atlantic, Midwest, New York, ERCOT, and all other power regions referred to collectively as “Other Power Regions” and 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 ComEd, PECO, BGE, Pepco, DPL, and ACE based on net income.

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

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

The CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on Revenues Net of Purchased Power and Fuel Expense (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF 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. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy, and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also excluded from the regional reportable segment amounts. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three and nine months ended September 30, 2021 and 2020 is as follows:

Three Months Ended September 30, 2021 and 2020

	Generation	ComEd	PECO	BGE	PHI	Other[(a)]	Intersegment Eliminations	Exelon
Operating revenues[(b)]:								
2021								
Competitive businesses electric revenues	$ 4,330	$ —	$ —	$ —	$ —	$ —	$ (319)	$ 4,011
Competitive businesses natural gas revenues	575	—	—	—	—	—	—	575
Competitive businesses other revenues	(499)	—	—	—	—	—	(3)	(502)
Rate-regulated electric revenues	—	1,789	762	677	1,444	—	(15)	4,657
Rate-regulated natural gas revenues	—	—	56	93	23	—	(3)	169
Shared service and other revenues	—	—	—	—	3	534	(537)	—
Total operating revenues	$ 4,406	$ 1,789	$ 818	$ 770	$ 1,470	$ 534	$ (877)	$ 8,910
2020								
Competitive businesses electric revenues	$ 4,201	$ —	$ —	$ —	$ —	$ —	$ (326)	$ 3,875
Competitive businesses natural gas revenues	323	—	—	—	—	—	—	323
Competitive businesses other revenues	135	—	—	—	—	—	(3)	132
Rate-regulated electric revenues	—	1,643	759	646	1,339	—	(22)	4,365
Rate-regulated natural gas revenues	—	—	54	85	23	—	(3)	159
Shared service and other revenues	—	—	—	—	6	484	(491)	(1)

Total operating revenues	$ 4,659	$ 1,643	$ 813	$ 731	$ 1,368	$ 484	$ (845)	$ 8,853

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Intersegment revenues[c]:								
2021	$ 324	$ 9	$ 2	$ 7	$ 3	$ 531	$ (876)	$ —
2020	331	15	3	6	6	485	(845)	1
Depreciation and amortization:								
2021	$ 866	$ 304	$ 86	$ 142	$ 210	$ 16	$ —	$ 1,624
2020	558	294	85	133	200	19	—	1,289
Operating expenses:								
2021	$ 3,465	$ 1,428	$ 677	$ 709	$ 1,155	$ 541	$ (858)	$ 7,117
2020	4,727	1,302	658	642	1,102	489	(833)	8,087
Interest expense, net:								
2021	$ 77	$ 98	$ 40	$ 36	$ 67	$ 79	$ —	$ 397
2020	80	95	39	34	67	89	—	404
Income (loss) before income taxes:								
2021	$ 814	$ 276	$ 108	$ 32	$ 264	$ (88)	$ —	$ 1,406
2020	219	256	122	61	215	(87)	—	786
Income Taxes:								
2021	$ 177	$ 56	$ (3)	$ (4)	$ (2)	$ (50)	$ —	$ 174
2020	100	60	(16)	8	(1)	65	—	216
Net income (loss):								
2021	$ 633	$ 220	$ 111	$ 36	$ 266	$ (37)	$ —	$ 1,229
2020	117	196	138	53	216	(151)	—	569
Capital Expenditures:								
2021	$ 367	$ 561	$ 301	$ 287	$ 410	$ 4	$ —	$ 1,930
2020	282	554	312	290	386	9	—	1,833

(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 expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for additional information on total utility taxes.

(c) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income. See Note 19 — Related Party Transactions for additional information on intersegment revenues.

PHI:

	Pepco	DPL	ACE	Other[a]	Intersegment Eliminations	PHI
Operating revenues[b]:						
2021						
Rate-regulated electric revenues	$ 660	$ 337	$ 451	$ —	$ (4)	$ 1,444
Rate-regulated natural gas revenues	—	23	—	—	—	23
Shared service and other revenues	—	—	—	92	(89)	3
Total operating revenues	$ 660	$ 360	$ 451	$ 92	$ (93)	$ 1,470
2020						
Rate-regulated electric revenues	$ 611	$ 314	$ 420	$ —	$ (6)	$ 1,339
Rate-regulated natural gas revenues	—	23	—	—	—	23
Shared service and other revenues	—	—	—	91	(85)	6
Total operating revenues	$ 611	$ 337	$ 420	$ 91	$ (91)	$ 1,368
Intersegment revenues[c]:						
2021	$ 2	$ 2	$ 1	$ 91	$ (93)	$ 3
2020	3	3	1	90	(91)	6
Depreciation and amortization:						
2021	$ 104	$ 53	$ 46	$ 7	$ —	$ 210
2020	96	48	48	8	—	200
Operating expenses:						
2021	$ 501	$ 295	$ 359	$ 93	$ (93)	$ 1,155
2020	465	296	338	94	(91)	1,102
Interest expense, net:						
2021	$ 35	$ 15	$ 14	$ 3	$ —	$ 67
2020	35	15	15	2	—	67
Income (loss) before income taxes:						
2021	$ 136	$ 53	$ 79	$ (4)	$ —	$ 264
2020	121	28	68	(2)	—	215
Income Taxes:						
2021	$ 6	$ 3	$ (11)	$ —	$ —	$ (2)
2020	3	1	(7)	2	—	(1)
Net income (loss):						
2021	$ 130	$ 50	$ 90	$ (4)	$ —	$ 266
2020	118	27	75	(4)	—	216
Capital Expenditures:						
2021	$ 202	$ 109	$ 97	$ 2	$ —	$ 410
2020	188	94	103	1	—	386

(a) Other primarily includes PHI's corporate operations, shared service entities, and other financing and investment activities.
(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for additional information on total utility taxes.
(c) Includes intersegment revenues with ComEd, BGE, and PECO, which are eliminated at Exelon.

The following tables disaggregate the Registrants' 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. For Generation, the disaggregation of revenues reflects Generation's two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon’s disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

Competitive Business Revenues (Generation):

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

	Three Months Ended September 30, 2020				
	Revenues from external customers(a)				
	Contracts with customers	Other(b)	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 1,327	$ (20)	$ 1,307	$ 6	$ 1,313
Midwest	974	68	1,042	1	1,043
New York	401	5	406	—	406
ERCOT	249	74	323	7	330
Other Power Regions	937	186	1,123	(14)	1,109
Total Competitive Businesses Electric Revenues	3,888	313	4,201	—	4,201
Competitive Businesses Natural Gas Revenues	169	154	323	—	323
Competitive Businesses Other Revenues(c)	85	50	135	—	135
Total Generation Consolidated Operating Revenues	$ 4,142	$ 517	$ 4,659	$ —	$ 4,659

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market losses of $635 million and gains of $37 million in 2021 and 2020, respectively, and elimination of intersegment revenues.

Revenues net of purchased power and fuel expense (Generation):

	Three Months Ended September 30, 2021			Three Months Ended September 30, 2020		
	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 567	$ 3	$ 570	$ 586	$ 5	$ 591
Midwest	655	—	655	748	2	750
New York	343	3	346	281	4	285
ERCOT	181	(2)	179	141	6	147
Other Power Regions	233	(22)	211	253	(28)	225
Total RNF for Reportable Segments	1,979	(18)	1,961	2,009	(11)	1,998
Other[(b)]	881	18	899	336	11	347
Total Generation RNF	$ 2,860	$ —	$ 2,860	$ 2,345	$ —	$ 2,345

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. includes:
- unrealized mark-to-market gains of $754 million and gains of $255 million in 2021 and 2020, respectively;
- accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 7 — Early Plant Retirements of $42 million and $24 million in 2021 and 2020 respectively; and
- the elimination of intersegment RNF.

Electric and Gas Revenue by Customer Class (Utility Registrants):

	Three Months Ended September 30, 2021						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Rate-regulated electric revenues							
Residential	$ 978	$ 509	$ 383	$ 782	$ 309	$ 198	$ 275
Small commercial & industrial	433	113	73	150	36	53	61
Large commercial & industrial	148	67	128	320	244	27	49
Public authorities & electric railroads	11	7	7	15	8	4	3
Other[a]	245	61	104	172	53	56	63
Total rate-regulated electric revenues[b]	$ 1,815	$ 757	$ 695	$ 1,439	$ 650	$ 338	$ 451
Rate-regulated natural gas revenues							
Residential	$ —	$ 36	$ 57	$ 10	$ —	$ 10	$ —
Small commercial & industrial	—	13	10	5	—	5	—
Large commercial & industrial	—	—	22	2	—	2	—
Transportation	—	5	—	3	—	3	—
Other[c]	—	2	6	3	—	3	—
Total rate-regulated natural gas revenues[d]	$ —	$ 56	$ 95	$ 23	$ —	$ 23	$ —
Total rate-regulated revenues from contracts with customers	$ 1,815	$ 813	$ 790	$ 1,462	$ 650	$ 361	$ 451
Other revenues							
Revenues from alternative revenue programs	$ (32)	$ 3	$ (24)	$ 6	$ 9	$ (2)	$ —
Other rate-regulated electric revenues[e]	6	2	3	2	1	1	—
Other rate-regulated natural gas revenues[e]	—	—	1	—	—	—	—
Total other revenues	$ (26)	$ 5	$ (20)	$ 8	$ 10	$ (1)	$ —
Total rate-regulated revenues for reportable segments	$ 1,789	$ 818	$ 770	$ 1,470	$ 660	$ 360	$ 451

	Three Months Ended September 30, 2020						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Rate-regulated electric revenues							
Residential	$ 920	$ 518	$ 389	$ 763	$ 307	$ 193	$ 263
Small commercial & industrial	379	104	65	134	36	45	53
Large commercial & industrial	135	66	113	262	195	21	46
Public authorities & electric railroads	10	7	7	14	8	3	3
Other[(a)]	234	58	78	141	47	44	50
Total rate-regulated electric revenues[(b)]	$ 1,678	$ 753	$ 652	$ 1,314	$ 593	$ 306	$ 415
Rate-regulated natural gas revenues							
Residential	$ —	$ 32	$ 55	$ 11	$ —	$ 11	$ —
Small commercial & industrial	—	16	9	6	—	6	—
Large commercial & industrial	—	—	21	1	—	1	—
Transportation	—	6	—	3	—	3	—
Other[(c)]	—	1	3	2	—	2	—
Total rate-regulated natural gas revenues[(d)]	$ —	$ 55	$ 88	$ 23	$ —	$ 23	$ —
Total rate-regulated revenues from contracts with customers	$ 1,678	$ 808	$ 740	$ 1,337	$ 593	$ 329	$ 415
Other revenues							
Revenues from alternative revenue programs	$ (38)	$ 5	$ (9)	$ 31	$ 18	$ 8	$ 5
Other rate-regulated electric revenues[(e)]	3	—	—	—	—	—	—
Other rate-regulated natural gas revenues[(e)]	—	—	—	—	—	—	—
Total other revenues	$ (35)	$ 5	$ (9)	$ 31	$ 18	$ 8	$ 5
Total rate-regulated revenues for reportable segments	$ 1,643	$ 813	$ 731	$ 1,368	$ 611	$ 337	$ 420

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates in 2021 and 2020 respectively of:
- $9 million, $15 million at ComEd
- $2 million, $3 million at PECO
- $4 million, $3 million at BGE
- $3 million, $6 million at PHI
- $2 million, $3 million at Pepco
- $2 million, $3 million at DPL
- $1 million, $1 million at ACE

(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates in 2021 and 2020 respectively of:
- less than $1 million at PECO both 2021 and 2020
- $3 million, $3 million at BGE

(e) Includes late payment charge revenues.

Nine Months Ended September 30, 2021 and 2020

	Generation	ComEd	PECO	BGE	PHI	Other[(a)]	Intersegment Eliminations	Exelon
Operating revenues[(b)]:								
2021								
Competitive businesses electric revenues	$ 12,264	$ —	$ —	$ —	$ —	$ —	$ (860)	$ 11,404

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Competitive businesses natural gas revenues	2,408	—	—	—	—	—	—	2,408
Competitive businesses other revenues	(555)	—	—	—	—	—	(9)	(564)
Rate-regulated electric revenues	—	4,840	2,033	1,866	3,726	—	(33)	12,432
Rate-regulated natural gas revenues	—	—	366	560	118	—	(9)	1,035
Shared service and other revenues	—	—	—	—	10	1,549	(1,559)	—
Total operating revenues	$ 14,117	$ 4,840	$ 2,399	$ 2,426	$ 3,854	$ 1,549	$ (2,470)	$ 26,715
2020								
Competitive businesses electric revenues	$ 11,367	$ —	$ —	$ —	$ —	$ —	$ (920)	$ 10,447
Competitive businesses natural gas revenues	1,348	—	—	—	—	—	(3)	1,345
Competitive businesses other revenues	557	—	—	—	—	—	(5)	552
Rate-regulated electric revenues	—	4,499	1,948	1,763	3,425	—	(50)	11,585
Rate-regulated natural gas revenues	—	—	358	521	116	—	(5)	990
Shared service and other revenues	—	—	—	—	13	1,440	(1,447)	6
Total operating revenues	$ 13,272	$ 4,499	$ 2,306	$ 2,284	$ 3,554	$ 1,440	$ (2,430)	$ 24,925
Intersegment revenues[c]:								
2021	$ 872	$ 19	$ 6	$ 20	$ 10	$ 1,542	$ (2,469)	$ —
2020	932	31	7	16	13	1,435	(2,430)	4
Depreciation and amortization:								
2021	$ 2,735	$ 893	$ 259	$ 434	$ 614	$ 52	$ 1	$ 4,988
2020	1,161	841	259	405	585	61	—	3,312
Operating expenses:								
2021	$ 14,605	$ 3,833	$ 1,908	$ 2,080	$ 3,167	$ 1,572	$ (2,407)	$ 24,758
2020	12,674	3,798	1,900	1,903	3,057	1,452	(2,397)	22,387
Interest expense, net:								
2021	$ 225	$ 292	$ 119	$ 103	$ 201	$ 241	$ (1)	$ 1,180
2020	277	287	108	99	201	269	—	1,241

	Generation	ComEd	PECO	BGE	PHI	Other[a]	Intersegment Eliminations	Exelon
Income (loss) before income taxes:								
2021	$ (8)	$ 750	$ 392	$ 266	$ 538	$ (264)	$ 1	$ 1,675
2020	532	446	310	299	340	(262)	—	1,665
Income Taxes:								
2021	$ 108	$ 141	$ 9	$ (24)	$ 3	$ (8)	$ —	$ 229
2020	41	142	(7)	26	(77)	16	—	141
Net income (loss):								
2021	$ (122)	$ 609	$ 383	$ 290	$ 535	$ (255)	$ 1	$ 1,441
2020	485	304	317	273	418	(278)	—	1,519
Capital Expenditures:								
2021	$ 1,086	$ 1,723	$ 878	$ 907	$ 1,299	$ 77	$ —	$ 5,970
2020	1,212	1,583	824	838	1,072	77	—	5,606
Total assets:								
September 30, 2021	$ 48,010	$ 36,002	$ 13,733	$ 12,197	$ 24,502	$ 8,387	$ (10,210)	$ 132,621
December 31, 2020	48,094	34,466	12,531	11,650	23,736	9,005	(10,165)	129,317

(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 expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for additional information on total utility taxes.

(c) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income. See Note 19 — Related Party Transactions for additional information on intersegment revenues.

PHI:

	Pepco	DPL	ACE	Other[a]	Intersegment Eliminations	PHI
Operating revenues[b]:						
2021						
Rate-regulated electric revenues	$ 1,736	$ 922	$ 1,080	$ —	$ (12)	$ 3,726
Rate-regulated natural gas revenues	—	118	—	—	—	118
Shared service and other revenues	—	—	—	281	(271)	10
Total operating revenues	$ 1,736	$ 1,040	$ 1,080	$ 281	$ (283)	$ 3,854
2020						
Rate-regulated electric revenues	$ 1,650	$ 838	$ 952	$ —	$ (15)	$ 3,425
Rate-regulated natural gas revenues	—	116	—	—	—	116
Shared service and other revenues	—	—	—	279	(266)	13
Total operating revenues	$ 1,650	$ 954	$ 952	$ 279	$ (281)	$ 3,554
Intersegment revenues[c]:						
2021	$ 4	$ 6	$ 2	$ 281	$ (283)	$ 10
2020	6	7	3	278	(281)	13
Depreciation and amortization:						
2021	$ 302	$ 157	$ 133	$ 22	$ —	$ 614
2020	282	143	134	26	—	585
Operating expenses:						
2021	$ 1,396	$ 858	$ 911	$ 285	$ (283)	$ 3,167
2020	1,364	843	847	284	(281)	3,057
Interest expense, net:						
2021	$ 104	$ 47	$ 43	$ 7	$ —	$ 201
2020	103	47	45	6	—	201
Income (loss) before income taxes:						
2021	$ 273	$ 144	$ 129	$ (8)	$ —	$ 538
2020	211	71	67	(9)	—	340
Income Taxes:						
2021	$ 9	$ 9	$ (12)	$ (3)	$ —	$ 3
2020	(16)	(20)	(39)	(2)	—	(77)
Net income (loss):						
2021	$ 264	$ 135	$ 141	$ (5)	$ —	$ 535
2020	227	91	106	(6)	—	418
Capital Expenditures:						
2021	$ 641	$ 320	$ 336	$ 2	$ —	$ 1,299
2020	512	278	281	1	—	1,072
Total assets:						
September 30, 2021	$ 9,748	$ 5,295	$ 4,532	$ 4,977	$ (50)	$ 24,502
December 31, 2020	9,264	5,140	4,286	5,079	(33)	23,736

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

(b) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses in the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for additional information on total utility taxes.

(c) Includes intersegment revenues with ComEd, BGE, and PECO, which are eliminated at Exelon.

The following tables disaggregate the Registrants' 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. For Generation, the disaggregation of revenues reflects Generation's two primary products of power sales and natural gas sales, with further disaggregation of power sales provided by geographic region. For the Utility Registrants, the disaggregation of revenues reflects the two primary utility services of rate-regulated electric sales and rate-regulated natural gas sales (where applicable), with further disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.

Competitive Business Revenues (Generation):

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

	Nine Months Ended September 30, 2020				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 3,692	$ (152)	$ 3,540	$ 21	$ 3,561
Midwest	2,773	240	3,013	(6)	3,007
New York	1,074	(12)	1,062	(1)	1,061
ERCOT	579	155	734	20	754
Other Power Regions	2,718	300	3,018	(34)	2,984
Total Competitive Businesses Electric Revenues	10,836	531	11,367	—	11,367
Competitive Businesses Natural Gas Revenues	881	467	1,348	—	1,348
Competitive Businesses Other Revenues[c]	268	289	557	—	557
Total Generation Consolidated Operating Revenues	$ 11,985	$ 1,287	$ 13,272	$ —	$ 13,272

(a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
(b) Includes revenues from derivatives and leases.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes unrealized mark-to-market losses of $958 million and gains of $238 million in 2021 and 2020, respectively, and elimination of intersegment revenues.

Revenues net of purchased power and fuel expense (Generation):

	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 1,698	$ 14	$ 1,712	$ 1,660	$ 23	$ 1,683
Midwest	2,014	1	2,015	2,180	(2)	2,178
New York	873	7	880	714	11	725
ERCOT	(775)	(147)	(922)	311	14	325
Other Power Regions	641	(77)	564	608	(70)	538
Total RNF for Reportable Segments	4,451	(202)	4,249	5,473	(24)	5,449
Other[b]	1,563	202	1,765	838	24	862
Total Generation RNF	$ 6,014	$ —	$ 6,014	$ 6,311	$ —	$ 6,311

(a) Includes purchases and sales from/to third parties and affiliated sales to the Utility Registrants.

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Primarily includes:
- unrealized mark-to-market gains of $1,242 million and gains of $472 million in 2021 and 2020, respectively;
- accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 7 — Early Plant Retirements of $148 million and $24 million in 2021 and 2020 respectively; and
- the elimination of intersegment RNF.

Electric and Gas Revenue by Customer Class (Utility Registrants):

	Nine Months Ended September 30, 2021						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Rate-regulated electric revenues							
Residential	$ 2,479	$ 1,325	$ 1,044	$ 1,924	$ 785	$ 535	$ 604
Small commercial & industrial	1,176	312	202	392	101	145	146
Large commercial & industrial	420	183	342	825	616	70	139
Public authorities & electric railroads	33	24	20	45	24	11	10
Other(a)	676	167	269	453	154	143	158
Total rate-regulated electric revenues(b)	$ 4,784	$ 2,011	$ 1,877	$ 3,639	$ 1,680	$ 904	$ 1,057
Rate-regulated natural gas revenues							
Residential	$ —	$ 251	$ 354	$ 67	$ —	$ 67	$ —
Small commercial & industrial	—	94	59	29	—	29	—
Large commercial & industrial	—	—	103	5	—	5	—
Transportation	—	17	—	11	—	11	—
Other(c)	—	4	41	6	—	6	—
Total rate-regulated natural gas revenues(d)	$ —	$ 366	$ 557	$ 118	$ —	$ 118	$ —
Total rate-regulated revenues from contracts with customers	$ 4,784	$ 2,377	$ 2,434	$ 3,757	$ 1,680	$ 1,022	$ 1,057
Other revenues							
Revenues from alternative revenue programs	$ 32	$ 20	$ (17)	$ 94	$ 54	$ 17	$ 23
Other rate-regulated electric revenues(e)	24	2	7	3	2	1	—
Other rate-regulated natural gas revenues(e)	—	—	2	—	—	—	—
Total other revenues	$ 56	$ 22	$ (8)	$ 97	$ 56	$ 18	$ 23
Total rate-regulated revenues for reportable segments	$ 4,840	$ 2,399	$ 2,426	$ 3,854	$ 1,736	$ 1,040	$ 1,080

	Nine Months Ended September 30, 2020						
Revenues from contracts with customers	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Rate-regulated electric revenues							
Residential	$ 2,389	$ 1,277	$ 1,034	$ 1,825	$ 779	$ 501	$ 545
Small commercial & industrial	1,067	291	183	355	101	127	127
Large commercial & industrial	388	174	311	755	558	66	131
Public authorities & electric railroads	33	21	20	45	25	10	10
Other[a]	663	171	233	471	166	148	159
Total rate-regulated electric revenues[b]	$ 4,540	$ 1,934	$ 1,781	$ 3,451	$ 1,629	$ 852	$ 972
Rate-regulated natural gas revenues							
Residential	$ —	$ 252	$ 342	$ 68	$ —	$ 68	$ —
Small commercial & industrial	—	86	55	30	—	30	—
Large commercial & industrial	—	—	96	3	—	3	—
Transportation	—	18	—	10	—	10	—
Other[c]	—	3	16	5	—	5	—
Total rate-regulated natural gas revenues[d]	$ —	$ 359	$ 509	$ 116	$ —	$ 116	$ —
Total rate-regulated revenues from contracts with customers	$ 4,540	$ 2,293	$ 2,290	$ 3,567	$ 1,629	$ 968	$ 972
Other revenues							
Revenues from alternative revenue programs	$ (51)	$ 10	$ (10)	$ (15)	$ 20	$ (15)	$ (20)
Other rate-regulated electric revenues[e]	10	3	3	2	1	1	—
Other rate-regulated natural gas revenues[e]	—	—	1	—	—	—	—
Total other revenues	$ (41)	$ 13	$ (6)	$ (13)	$ 21	$ (14)	$ (20)
Total rate-regulated revenues for reportable segments	$ 4,499	$ 2,306	$ 2,284	$ 3,554	$ 1,650	$ 954	$ 952

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates in 2021 and 2020 respectively of:
- $19 million, $31 million at ComEd
- $5 million, $6 million at PECO
- $10 million, $9 million at BGE
- $10 million, $13 million at PHI
- $4 million, $6 million at Pepco
- $6 million, $7 million at DPL
- $2 million, $3 million at ACE

(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates in 2021 and 2020 respectively of:
- $1 million, $1 million at PECO
- $10 million, $7 million at BGE

(e) Includes late payment charge revenues.

6. Accounts Receivable (All Registrants)

Allowance for Credit Losses on Accounts Receivable (All Registrants)

The following tables present the rollforward of Allowance for Credit Losses on Customer Accounts Receivable.

	Three Months Ended September 30, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of June 30, 2021	$ 395	$ 75	$ 89	$ 111	$ 27	$ 93	$ 38	$ 19	$ 36
Plus: Current period provision for expected credit losses[a]	47	10	11	1	7	18	5	3	10
Less: Write-offs, net of recoveries[b]	33	1	12	11	3	6	2	4	—
Balance as of September 30, 2021	$ 409	$ 84	$ 88	$ 101	$ 31	$ 105	$ 41	$ 18	$ 46

	Three Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of June 30, 2020	$ 261	$ 33	$ 72	$ 71	$ 23	$ 62	$ 24	$ 18	$ 20
Plus: Current period provision for expected credit losses[c]	114	1	37	27	14	35	11	7	17
Less: Write-offs, net of recoveries[b]	17	1	4	2	2	8	—	3	5
Balance as of September 30, 2020	$ 358	$ 33	$ 105	$ 96	$ 35	$ 89	$ 35	$ 22	$ 32

	Nine Months Ended September 30, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
lance as of December 31, 2020	$ 366	$ 32	$ 97	$ 116	$ 35	$ 86	$ 32	$ 22	$ 32
us: Current period provision for expected credit losses(d)	122	57	23	7	2	33	15	4	14
ss: Write-offs, net of recoveries(b)	79	5	32	22	6	14	6	8	—
lance as of September 30, 2021	$ 409	$ 84	$ 88	$ 101	$ 31	$ 105	$ 41	$ 18	$ 46

	Nine Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
lance as of December 31, 2019	$ 243	$ 80	$ 59	$ 55	$ 12	$ 37	$ 13	$ 11	$ 13
us: Current period provision for expected credit losses(c)	222	13	62	56	28	63	24	14	25
ss: Write-offs, net of recoveries(b)	51	4	16	15	5	11	2	3	6
ss: Sale of customer accounts receivable(e)	56	56	—	—	—	—	—	—	—
lance as of September 30, 2020	$ 358	$ 33	$ 105	$ 96	$ 35	$ 89	$ 35	$ 22	$ 32

(a) For ACE, the increase is primarily a result of increased aging of receivables and a slight decrease in the expected recovery rate.
(b) Recoveries were not material to the Registrants.
(c) For the Utility Registrants, the increase is primarily as a result of increased aging of receivables, the temporary suspension of customer disconnections for non-payment, temporary cessation of new late payment fees, and reconnections of service to customers previously disconnected due to COVID-19.
(d) For Generation, primarily relates to the impacts of the February 2021 extreme cold weather event. See Note 3 — Regulatory Matters for additional information. For PHI, Pepco, and ACE, the increase is primarily a result of increased aging of receivables and a slight decrease in the expected recovery rate.
(e) See below for additional information on the sale of customer accounts receivable at Generation in the second quarter of 2020.

The following tables present the rollforward of Allowance for Credit Losses on Other Accounts Receivable.

	Three Months Ended September 30, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of June 30, 2021	$ 72	$ 1	$ 18	$ 7	$ 8	$ 38	$ 16	$ 9	$ 13
Plus: Current period provision for expected credit losses	9	3	2	1	1	2	1	(1)	2
Less: Write-offs, net of recoveries[(a)]	4	—	1	1	1	—	—	—	—
Balance as of September 30, 2021	$ 77	$ 4	$ 19	$ 7	$ 8	$ 40	$ 17	$ 8	$ 15

	Three Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of June 30, 2020	$ 61	$ —	$ 22	$ 7	$ 6	$ 26	$ 11	$ 7	$ 8
Plus: Current period provision for expected credit losses	15	—	5	1	3	6	2	1	3
Less: Write-offs, net of recoveries[(a)]	1	—	—	1	—	—	—	—	—
Balance as of September 30, 2020	$ 75	$ —	$ 27	$ 7	$ 9	$ 32	$ 13	$ 8	$ 11

	Nine Months Ended September 30, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2020	$ 71	$ —	$ 21	$ 8	$ 9	$ 33	$ 13	$ 9	$ 11
Plus: Current period provision for expected credit losses	15	4	—	2	2	7	4	(1)	4
Less: Write-offs, net of recoveries[(a)]	9	—	2	3	3	—	—	—	—
Balance as of September 30, 2021	$ 77	$ 4	$ 19	$ 7	$ 8	$ 40	$ 17	$ 8	$ 15

	Nine Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance as of December 31, 2019	$ 48	$ —	$ 20	$ 7	$ 5	$ 16	$ 7	$ 4	$ 5
Plus: Current period provision for expected credit losses	36	—	9	3	7	17	6	4	7
Less: Write-offs, net of recoveries[(a)]	9	—	2	3	3	1	—	—	1
Balance as of September 30, 2020	$ 75	$ —	$ 27	$ 7	$ 9	$ 32	$ 13	$ 8	$ 11

(a) Recoveries were not material to the Registrants.

Unbilled Customer Revenue (All Registrants)

The following table provides additional information about unbilled customer revenues recorded in the Registrants' Consolidated Balance Sheets as of September 30, 2021 and December 31, 2020.

	Unbilled customer revenues[(a)]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2021	$ 941	$ 359	$ 224	$ 113	$ 98	$ 147	$ 70	$ 34	$ 43
December 31, 2020	998	258	218	147	197	178	87	62	29

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

Sales of Customer Accounts Receivable (Exelon and Generation)

On April 8, 2020, NER, a bankruptcy remote, special purpose entity, which is wholly-owned by Generation, entered into a revolving accounts receivable financing arrangement with a number of financial institutions and a commercial paper conduit (the Purchasers) to sell certain customer accounts receivable (the Facility). The Facility had a maximum funding limit of $750 million and was scheduled to expire on April 7, 2021, unless renewed by the mutual consent of the parties in accordance with its terms. The Facility was renewed on March 29, 2021. The Facility term was extended through March 29, 2024, unless further renewed by the mutual consent of the parties, and the maximum funding limit was increased to $900 million. Under the Facility, NER may sell eligible short-term customer accounts receivable to the Purchasers in exchange for cash and subordinated interest. The transfers are reported as sales of receivables in Exelon’s and Generation’s consolidated financial statements. The subordinated interest in collections upon the receivables sold to the Purchasers is referred to as the DPP, which is reflected in Other current assets in Exelon’s and Generation’s Consolidated Balance Sheets.

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

On April 8, 2020, Generation derecognized and transferred approximately $1.2 billion of receivables at fair value to the Purchasers in exchange for approximately $500 million in cash purchase price and $650 million of DPP.

During the first quarter of 2021, Generation received additional cash of $250 million from the Purchasers for the remaining available funding in the Facility.

Additionally, during the first quarter of 2021, Generation received cash of approximately $150 million from the Purchasers in connection with the increased funding limit at the time of the Facility renewal.

During the second quarter of 2021, Generation returned cash of $50 million to the Purchasers due to the eligible receivables decreasing temporarily. Subsequently, in the second quarter, Generation received cash of $ 50 million from the Purchasers as a result of an increase in the eligible receivable balance. The $50 million cash outflow and inflow is included in the Collection of DPP line within Cash flows from investing activities in Exelon’s and Generation’s Consolidated Statements of Cash Flows.

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

	September 30, 2021	December 31, 2020
Derecognized receivables transferred at fair value	$ 1,401	$ 1,139
Cash proceeds received	900	500
DPP	501	639

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Loss on sale of receivables[(a)]	$ 1	$ 8	$ 26	$ 23

(a) Reflected in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

	Nine Months Ended September 30,	
	2021	2020
Proceeds from new transfers[(a)]	$ 4,440	$ 1,889
Cash collections received on DPP and reinvested in the Facility[(b)]	2,652	2,518
Cash collections reinvested in the Facility	7,092	4,407

(a) Customer accounts receivable sold into the Facility were $7,373 million and $4,515 million for the nine months ended September 30, 2021 and September 30, 2020, respectively.
(b) Does not include the $400 million in cash proceeds received from the Purchasers in the first quarter of 2021.

Generation's risk of loss following the transfer of accounts receivable is limited to the DPP outstanding. Payment of DPP is not subject to significant risks other than delinquencies and credit losses on accounts receivable transferred, which have historically been and are expected to be immaterial. Generation continues to service the receivables sold in exchange for a servicing fee. Generation did not record a servicing asset or liability as the servicing fees were immaterial.

Generation recognizes the cash proceeds received upon sale in Net cash provided by operating activities in the Consolidated Statements of Cash Flows. The collection and reinvestment of DPP is recognized in Net cash provided by investing activities in the Consolidated Statements of Cash Flows.

See Note 14 — Fair Value of Financial Assets and Liabilities and Note 17 — Variable Interest Entities for additional information.

Other Purchases and Sales of Customer and Other Accounts Receivables (All Registrants)

Generation is required, under supplier tariffs in ISO-NE, MISO, NYISO, and PJM, to sell customer and other receivables to utility companies, which include the Utility Registrants. The Utility Registrants are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia, Delaware, and New Jersey, to purchase certain receivables from alternative retail electric and, as applicable, natural gas suppliers that participate in the utilities' consolidated billing. The following tables present the total receivables purchased and sold.

	Nine Months Ended September 30, 2021								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total receivables purchased	$ 2,945	$ —	$ 810	$ 795	$ 531	$ 826	$ 504	$ 166	$ 156
Total receivables sold	100	117	—	—	—	—	—	—	—
Related party transactions:									
Receivables purchased from Generation	—	—	—	—	17	—	—	—	—
Receivables sold to the Utility Registrants	—	17	—	—	—	—	—	—	—

	Nine Months Ended September 30, 2020								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Total receivables purchased	$ 2,698	$ —	$ 865	$ 786	$ 508	$ 787	$ 484	$ 160	$ 143
Total receivables sold	542	790	—	—	—	—	—	—	—
Related party transactions:									
Receivables purchased from Generation	—	—	34	67	75	72	51	13	8
Receivables sold to the Utility Registrants	—	248	—	—	—	—	—	—	—

7. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continuously evaluate factors that affect the current and expected economic value of Generation’s plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

On August 27, 2020, Generation announced that it intended to permanently cease generation operations at Byron in September 2021 and at Dresden in November 2021. Neither of these nuclear plants cleared in PJM's capacity auction for the 2022-2023 planning year held in May 2021. Generation's Braidwood and LaSalle nuclear plants in Illinois did clear in the capacity auction, but were also showing increased signs of economic distress.

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois will be eligible to participate in the CMC procurement process and, if awarded contracts, would be committed to operate through May 31, 2027. See Note 3 — Regulatory Matters for additional information. Following enactment of the legislation, Generation announced on September 15, 2021, that it has reversed its previous decision to retire Byron and Dresden given the opportunity for additional revenue under the Clean Energy Law. In addition, Generation no longer considers the Braidwood or LaSalle nuclear plants to be at risk for premature retirement.

As a result of the decision to early retire Byron and Dresden, Exelon and Generation recognized certain one-time charges in the third and fourth quarters of 2020 related to materials and supplies inventory reserve adjustments, employee-related costs including severance benefit costs, and construction work-in-progress impairments, among other items. In addition, there were ongoing annual financial impacts stemming from shortening the expected economic useful lives of these nuclear plants primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and changes in ARO accretion expense associated with the changes in decommissioning timing and cost assumptions to reflect an earlier retirement date.

In the third quarter of 2021, Exelon and Generation reversed $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in Operating and maintenance expense in the third and fourth quarters of 2020 associated with the early retirements. In addition, Generation updated the expected economic useful life for both facilities to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively, the end of the respective NRC operating license for each unit. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. See Note 8 — Nuclear Decommissioning for additional detail on changes to the nuclear decommissioning ARO balances resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden.

The total impact for the three and nine months ended September 30, 2021 and 2020 in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income resulting from the initial decision and subsequent reversal of the decision to early retire Byron and Dresden is summarized in the table below.

Income statement expense (pre-tax)	**Three Months Ended September 30, 2021**	**Nine Months Ended September 30, 2021**	**Three and Nine Months Ended September 30, 2020**
Depreciation and amortization			
Accelerated depreciation[(a)]	$ 574	$ 1,805	$ 254
Accelerated nuclear fuel amortization	42	148	14
Operating and maintenance			
One-time charges	(94)	(94)	220
Other charges	4	8	34
Contractual offset[(b)]	(60)	(451)	(129)
Total	$ 466	$ 1,416	$ 393

(a) Includes the accelerated depreciation of plant assets including any ARC.

(b) Reflects contractual offset for ARO accretion and ARC depreciation and excludes any changes in earnings in the NDT funds. Decommissioning-related impacts were not offset for the Byron units starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset in Exelon's and Generation's Consolidated

Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activities result in a regulatory liability at ComEd. The offset resulted in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. See Note 8 — Nuclear Decommissioning for additional information.

Generation remains committed to continued operations for its other nuclear plants receiving state-supported payments under the Illinois ZES (Clinton and Quad Cities), New Jersey ZEC program (Salem), and the New York CES (FitzPatrick, Ginna, and Nine Mile Point) assuming the continued effectiveness of such programs. To the extent such programs do not operate as expected over their full terms, each of these plants would be at heightened risk for early retirement, which could have a material impact on Exelon's and Generation's future financial statements. See Note 3 — Regulatory Matters for additional information on the New Jersey ZEC program and Note 3 — Regulatory Matters of the 2020 Form 10-K for additional information on the Illinois ZES and New York CES.

Exelon continues to work with stakeholders on state policy solutions to support continued operation of our nuclear fleet, while also advocating for broader market reforms at the regional and federal level. The absence of such solutions or reforms could have a material unfavorable impact on Exelon's and Generation's future results of operations.

Other Generation

In March 2018, Generation notified ISO-NE of its plans to early retire, among other assets, the Mystic Generating Station's units 8 and 9 (Mystic 8 and 9) absent regulatory reforms to properly value reliability and regional fuel security. Thereafter, ISO-NE identified Mystic 8 and 9 as being needed to ensure fuel security for the region and entered into a cost of service agreement with these two units for the period between June 1, 2022 - May 31, 2024. The agreement was approved by FERC in December 2018.

On June 10, 2020, Generation filed a complaint with FERC against ISO-NE stating that ISO-NE failed to follow its tariff with respect to its evaluation of Mystic 8 and 9 for transmission security for the 2024 to 2025 Capacity Commitment Period and that the modifications that ISO-NE made to its unfiled planning procedures to avoid retaining Mystic 8 and 9 should have been filed with FERC for approval. On August 17, 2020, FERC issued an order denying the complaint. As a result, on August 20, 2020, Exelon determined that Generation will permanently cease generation operations at Mystic 8 and 9 at the expiration of the cost of service commitment in May 2024. See Note 3 — Regulatory Matters for additional discussion of Mystic's cost of service agreement.

As a result of the decision to early retire Mystic 8 and 9, Exelon and Generation recognized $43 million in the third quarter of 2020 of one-time charges related to an expected long-term contract termination and materials and supplies reserve adjustments, among other items. In addition, there are financial impacts stemming from shortening the expected economic useful life of Mystic 8 and 9 primarily related to accelerated depreciation of plant assets. Exelon and Generation recorded an immaterial amount of incremental Depreciation and amortization expense for the three months ended September 30, 2021 and $41 million for the nine months ended September 30, 2021. Exelon and Generation recorded incremental Depreciation and amortization expense of $6 million for the three and nine months ended September 30, 2020.

8. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models, and discount rates. Generation updates its ARO annually, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The financial statement impact for changes in the ARO, on an individual unit basis, due to the changes in and timing of estimated cash flows generally result in a corresponding change in the unit's ARC in Property, plant, and equipment in Exelon's and Generation's Consolidated Balance Sheets. If the ARO decreases for a Non-Regulatory Agreement unit without any remaining ARC, the corresponding change is recorded as decrease in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The following table provides a rollforward of the nuclear decommissioning ARO reflected in Exelon's and Generation's Consolidated Balance Sheets from December 31, 2020 to September 30, 2021:

Nuclear decommissioning ARO at December 31, 2020[(a)]	$	11,922
Accretion expense		375
Net increase due to changes in, and timing of, estimated future cash flows		256
Costs incurred related to decommissioning plants		(57)
Nuclear decommissioning ARO at September 30, 2021[(a)]	$	12,496

(a) Includes $74 million and $80 million as the current portion of the ARO at September 30, 2021 and December 31, 2020, which is included in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets.

During the nine months ended September 30, 2021, the net $256 million increase in the ARO for the changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments. These adjustments primarily include:

- An increase of approximately $510 million for updated cost escalation rates, primarily for labor and energy, and a decrease in discount rates.
- A net decrease of approximately $170 million was driven by updates to Byron and Dresden reflecting changes in assumed retirement dates and assumed methods of decommissioning as a result of the reversal of the decision to early retire the plants. See Note 7 — Early Plant Retirements for additional information.
- A net decrease of approximately $110 million due to lower estimated costs to decommission Byron, Braidwood, Dresden, LaSalle, and Zion nuclear units resulting from the completion of updated cost studies.

The 2021 ARO updates resulted in a decrease of $51 million in Operating and maintenance expense for the three and nine months ended September 30, 2021 in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

NDT Funds

Exelon and Generation had NDT funds totaling $15,602 million and $14,599 million at September 30, 2021 and December 31, 2020, respectively. The NDT funds also include $198 million and $134 million for the current portion of the NDT funds at September 30, 2021 and December 31, 2020, respectively, which are included in Other current assets in Exelon's and Generation's Consolidated Balance Sheets. See Note 18 — Supplemental Financial Information for additional information on activities of the NDT funds.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, decommissioning-related activities net of applicable taxes, including realized and unrealized gains and losses on the NDT funds, depreciation of the ARC, and accretion of the decommissioning obligation, are generally offset in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are recorded by Generation and the corresponding regulated utility as a component of the intercompany and regulatory balances in the balance sheet. For the purposes of making this determination, the decommissioning obligation referred to is different from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

For the former ComEd units, given no further recovery from ComEd customers is permitted and Generation retains an obligation to ultimately return any unused NDTs to ComEd customers (on a unit-by-unit basis), to the extent the related NDT investment balances are expected to exceed the total estimated decommissioning obligation for each unit, decommissioning-related activities are offset in the Consolidated Statements of Operations and Comprehensive Income which results with Generation recognizing an intercompany payable to ComEd while ComEd records an intercompany receivable from Generation with a corresponding regulatory liability. However, given the asymmetric settlement provision that does not allow for continued recovery from ComEd customers in the event of a shortfall, recognition of a regulatory asset at ComEd is not permissible and accounting for decommissioning-related activities at Generation for that unit would not be offset, and the impact to Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income could be material during such periods. During the second and third quarter of 2021, a pre-tax charge of $53 million and $140 million, respectively, was recorded in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income for decommissioning-related activities that were not offset for the Byron units due to contractual offset being temporarily suspended. With Generation’s September 15, 2021 reversal of the previous decision to retire Byron and the corresponding adjustment to the ARO for Byron discussed previously, Generation resumed contractual offset for Byron as of that date.

As of September 30, 2021, decommissioning-related activities for all of the former ComEd units, except for Zion, are currently offset in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life.

Generation filed its biennial decommissioning funding status report with the NRC on February 24, 2021 for all units, including its shutdown units, except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions, LLC. The status report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for all units except for Byron Units 1 and 2. Generation filed an updated decommissioning funding status report for Byron Units 1 and 2 and Dresden Units 2 and 3 on September 28, 2021 based on their current license expiration dates consistent with Generation’s announcements regarding the continued operations of these units. This report demonstrated adequate decommissioning funding assurance as of December 31, 2020 for Byron Units 1 and 2 and Dresden Units 2 and 3.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2022. This report will reflect the status of decommissioning funding assurance as of December 31, 2021 for shutdown units.

9. Asset Impairments (Exelon and Generation)

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

New England Asset Group

In the third quarter of 2020, in conjunction with the retirement announcement of Mystic Units 8 and 9, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the estimated undiscounted future cash flows and fair value of the New England asset group were less than their carrying values. As a result, a pre-tax impairment charge of $500 million was recorded in the third quarter of 2020 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. See Note 7 — Early Plant Retirements for additional information.

In the second quarter of 2021, an overall decline in the asset group's portfolio value suggested that the carrying value of the New England asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and concluded that the carrying value was not recoverable and that its fair value was less than its carrying value. As a result, a pre-tax impairment charge of $350 million was recorded in the second quarter of 2021 in Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

Contracted Wind Project

In the third quarter of 2021, significant long-term operational issues anticipated for a specific wind turbine technology suggested that the carrying value of a contracted wind asset, located in Maryland and part of the EGRP joint venture, may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows and concluded that the carrying value of this contracted wind project was not recoverable and that its fair value was less than its carrying value. As a result, in the third quarter of 2021, a pre-tax impairment charge of $45 million was recorded in Operating and maintenance expense, $21 million of which was offset in Net income attributable to noncontrolling interests in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

10. Income Taxes (All Registrants)

Rate Reconciliation

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

	Three Months Ended September 30, 2021								
	Exelon[a]	Generation[a]	ComEd[a]	PECO[a][b]	BGE[a][b]	PHI[a]	Pepco[a]	DPL[a]	ACE[a][b]
U.S. Federal statutory rate	21.0%	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	6.0	4.4	8.0	(4.1)	(13.0)	5.0	3.4	6.4	7.0
Qualified NDT fund income	0.5	0.9	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.4)	(0.7)	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Plant basis differences	(1.7)	—	(0.8)	(16.2)	(1.4)	(1.3)	(2.0)	(0.6)	(0.6)
Production tax credits and other credits	(1.0)	(1.4)	(0.5)	—	(0.9)	(0.5)	(0.5)	(0.4)	(0.5)
Noncontrolling interests	(0.4)	(0.6)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.8)	—	(7.6)	(3.4)	(17.3)	(24.9)	(17.6)	(19.9)	(41.4)
Other[c]	(4.8)	(1.9)	0.3	(0.1)	(0.8)	—	0.1	(0.6)	0.8
Effective income tax rate	12.4%	21.7%	20.3%	(2.8)%	(12.5)%	(0.8)%	4.4%	5.7%	(13.9)%

	Three Months Ended September 30, 2020								
	Exelon[a]	Generation[a]	ComEd[a]	PECO[a][d]	BGE[a][d]	PHI[a][d]	Pepco[a][d]	DPL[a][d]	ACE[a][d]
U.S. Federal statutory rate	21.0%	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	12.3	(10.3)	8.1	(6.2)	5.1	5.5	4.6	6.6	6.9
Qualified NDT fund income	13.2	47.4	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.4)	(4.5)	(0.2)	—	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(4.3)	—	(0.6)	(23.3)	(1.2)	(1.5)	(2.1)	(0.4)	(1.3)
Production tax credits and other credits	(3.0)	(9.2)	(0.4)	—	(0.8)	(0.5)	(0.5)	(0.5)	(0.4)
Noncontrolling interests	0.8	2.9	—	—	—	—	—	—	—
Excess deferred tax amortization	(10.1)	—	(5.6)	(3.8)	(10.6)	(24.9)	(20.0)	(23.6)	(36.8)
Tax Settlements	(0.2)	(0.7)	—	—	—	—	—	—	—
Other	(0.8)	(0.9)	1.1	(0.8)	(0.3)	0.1	(0.4)	0.7	0.6
Effective income tax rate	27.5%	45.7%	23.4%	(13.1)%	13.1%	(0.5)%	2.5%	3.6%	(10.3)%

(a) Positive percentages represent income tax expense. Negative percentages represent income tax benefit.
(b) For PECO, the income tax benefit is primarily due 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 ACE, the income tax benefit is primarily due to a distribution rate case settlement which allows ACE to retain certain tax benefits.

(c) For Exelon, "Other" is primarily driven by the reversal of the consolidating income tax adjustment recorded at Exelon Corporate in the first quarter of 2021 that was required pursuant to GAAP interim reporting guidance.

(d) At PECO, the lower effective tax rate is primarily related to an increase in plant basis differences attributable to storm tax repair deductions. At BGE, PHI, Pepco, DPL and ACE, the lower effective tax rate is primarily attributable to accelerated amortization of transmission related deferred income tax regulatory liabilities as a result of regulatory settlements.

	Nine Months Ended September 30, 2021								
	Exelon[(a)]	**Generation**[(b)]	**ComEd**[(a)]	**PECO**[(a)(c)]	**BGE**[(a)(c)]	**PHI**[(a)]	**Pepco**[(a)]	**DPL**[(a)]	**ACE**[(a)(c)]
U.S. Federal statutory rate	21.0%	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	3.0	90.2	7.6	(2.6)	(10.8)	4.6	2.5	6.5	7.3
Qualified NDT fund income	9.4	(1,932.6)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.8)	130.6	(0.1)	—	(0.1)	(0.1)	—	(0.2)	(0.2)
Plant basis differences	(3.9)	—	(0.7)	(12.6)	(1.5)	(1.3)	(1.9)	(0.7)	(0.6)
Production tax credits and other credits	(2.6)	425.1	(0.5)	—	(0.9)	(0.5)	(0.5)	(0.4)	(0.5)
Noncontrolling interests	(0.7)	145.2	—	—	—	—	—	—	—
Excess deferred tax amortization	(13.9)	—	(7.2)	(3.3)	(16.0)	(22.8)	(17.4)	(19.7)	(36.3)
Other[(d)]	2.2	(229.5)	(1.3)	(0.2)	(0.7)	(0.3)	(0.4)	(0.2)	—
Effective income tax rate	13.7%	(1,350.0)%	18.8%	2.3%	(9.0)%	0.6%	3.3%	6.3%	(9.3)%

	Nine Months Ended September 30, 2020								
	Exelon[(a)]	**Generation[(a)]**	**ComEd[(a)(e)]**	**PECO[(a)(e)]**	**BGE[(a)(e)]**	**PHI[(a)(e)]**	**Pepco[(a)(e)]**	**DPL[(a)(e)]**	**ACE[(a)(e)]**
U.S. Federal statutory rate	21.0%	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	9.3	—	12.7	(3.4)	5.5	5.0	4.2	6.5	6.8
Qualified NDT fund income	3.2	10.0	—	—	—	—	—	—	—
Deferred Prosecution Agreement payments	2.5	—	9.4	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(3.2)	(0.3)	—	(0.1)	(0.2)	(0.1)	(0.3)	(0.5)
Plant basis differences	(4.0)	—	(0.9)	(15.9)	(1.8)	(2.2)	(2.4)	(0.5)	(3.7)
Production tax credits and other credits	(2.6)	(7.0)	(0.4)	—	(0.4)	(0.3)	(0.3)	(0.2)	(0.4)
Noncontrolling interests	1.0	3.1	—	—	—	—	—	—	—
Excess deferred tax amortization	(15.8)	—	(11.8)	(3.5)	(15.0)	(45.3)	(29.2)	(53.6)	(81.4)
Tax Settlements[(f)]	(5.0)	(15.7)	—	—	—	—	—	—	—
Other	0.1	(0.5)	2.1	(0.5)	(0.5)	(0.6)	(0.8)	(1.1)	—
Effective income tax rate	8.5%	7.7%	31.8%	(2.3)%	8.7%	(22.6)%	(7.6)%	(28.2)%	(58.2)%

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

(b) Generation recognized a loss before income taxes for the nine months ended September 30, 2021. As a result, a negative percentage represents an income tax expense for the period presented.

(c) For PECO, the lower effective tax rate is primarily related to an increase in 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 ACE, the income tax benefit is primarily due to a distribution rate case settlement which allows ACE to retain certain tax benefits.

(d) For Exelon, "Other" is primarily driven by the consolidating income tax adjustment recorded at Exelon Corporate in the first quarter of 2021 that was required pursuant to GAAP interim reporting guidance. This incremental expense will reverse by year-end and will not have an impact on annual results.

(e) For ComEd, the higher effective tax rate is primarily related to the nondeductible Deferred Prosecution Agreement payments. For PECO, the income tax benefit is primarily related to an increase in plant basis differences attributable to storm tax repairs deductions. For BGE, PHI, Pepco, DPL, and ACE, the income tax benefit is primarily attributable to accelerated amortization of transmission related deferred income tax regulatory liabilities as a result of regulatory settlements.

(f) Exelon's and Generation's unrecognized federal and state tax benefits decreased in the first quarter of 2020 by approximately $411 million due to the settlement of a federal refund claim with IRS Appeals. The recognition of these tax benefits resulted in an increase to Exelon's and Generation's net income of $76 million and $73 million, respectively, in the first quarter of 2020, reflecting a decrease to Exelon's and Generation's income tax expense of $67 million.

Unrecognized Tax Benefits

PHI and ACE have the following unrecognized tax benefits as of September 30, 2021 and December 31, 2020. Exelon's, Generation's, ComEd's, PECO's, BGE's, Pepco's, and DPL's amounts are not material.

	PHI	ACE
September 30, 2021	$ 56	$ 16
December 31, 2020	52	15

Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

As of September 30, 2021, 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.

Other Income Tax Matters

CENG Put Option (Exelon and Generation)

On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation purchased EDF's equity interest in CENG. Exelon and Generation recorded deferred tax liabilities of $290 million and $288 million, respectively, against Common Stock in Exelon's Consolidated Balance Sheet and Membership Interest in Generation's Consolidated Balance Sheet. The deferred tax liabilities represent the tax effect on the difference between the net purchase price and EDF's noncontrolling interest as of August 6, 2021. The deferred tax liabilities will reverse during the remaining operating lives and during decommissioning of the CENG nuclear plants. See Note 2 – Mergers, Acquisitions, and Dispositions for additional information.

Long-Term Marginal State Income Tax Rate (All Registrants)

In the third quarter of 2021 and 2020, Exelon updated its marginal state income tax rates for changes in state apportionment. The changes in marginal rates in the third quarter of 2021 resulted in an increase of $27 million to the deferred income tax liability at Exelon, and a corresponding adjustment to income tax expense, net of federal taxes. The changes in marginal rates in the third quarter of 2020 resulted in an increase of $66 million and a decrease of $26 million to the deferred income tax liability at Exelon and Generation, respectively. Exelon and Generation recorded a corresponding adjustment to income tax expense, net of federal taxes.

Allocation of Tax Benefits (All Registrants)

Generation and the Utility Registrants are all 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 benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit.

The following table presents the allocation of federal tax benefits from Exelon under the Tax Sharing Agreement.

	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2021	$ 64	$ 1	$ 19	$ —	$ 17	$ 16	$ —	$ —
September 30, 2020	64	14	17	—	17	8	6	1

11. Retirement Benefits (All Registrants)

Defined Benefit Pension and OPEB

During the first quarter of 2021, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2021. This valuation resulted in an increase to the pension obligations of $33 million and a decrease to the OPEB obligations of $9 million. Additionally, accumulated other comprehensive loss increased by $1 million (after-tax) and regulatory assets and liabilities increased by $21 million and $1 million, respectively.

The majority of the 2021 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 2.58%. The majority of the 2021 OPEB cost is calculated using an expected long-term rate of return on plan assets of 6.46% for funded plans and a discount rate of 2.51%.

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 three and nine months ended September 30, 2021 and 2020.

	Pension Benefits		OPEB	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2021	2020	2021	2020
Components of net periodic benefit cost:				
Service cost	$ 110	$ 97	$ 20	$ 22
Interest cost	161	190	29	37
Expected return on assets	(335)	(317)	(40)	(41)
Amortization of:				
Prior service cost (credit)	1	1	(8)	(30)
Actuarial loss	150	128	9	12
Settlement charges	12	8	—	—
Net periodic benefit cost	$ 99	$ 107	$ 10	$ —

	Pension Benefits		OPEB	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Components of net periodic benefit cost:				
Service cost	$ 330	$ 290	$ 60	$ 67
Interest cost	481	569	86	114
Expected return on assets	(1,003)	(953)	(119)	(122)
Amortization of:				
Prior service cost (credit)	3	3	(25)	(92)
Actuarial loss	449	384	27	36
Curtailment benefits	—	—	(1)	—
Settlement charges	16	14	—	—
Net periodic benefit cost	$ 276	$ 307	$ 28	$ 3

The amounts below represent the Registrants' allocated pension and OPEB costs. 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 Generation and 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and OPEB Costs	**2021**	**2020**	**2021**	**2020**
Exelon	$ 109	$ 107	$ 304	$ 310
Generation	36	30	92	89
ComEd	32	29	97	85
PECO	2	1	5	4
BGE	16	16	47	47
PHI	12	17	36	52
Pepco	2	4	5	11
DPL	1	2	2	6
ACE	3	3	8	10

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow 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 matching contributions to the savings plans for the three and nine months ended September 30, 2021 and 2020, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Savings Plans Matching Contributions	**2021**	**2020**	**2021**	**2020**
Exelon	$ 38	$ 37	$ 107	$ 104
Generation	14	14	40	41
ComEd	9	9	27	25
PECO	2	3	8	8
BGE	4	4	8	8
PHI	5	3	12	9
Pepco	1	1	3	3
DPL	1	1	3	2
ACE	1	—	2	1

12. Derivative Financial Instruments (All Registrants)

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

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

Authoritative guidance about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheets. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referenced contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. In the tables below, which present fair value balances, Generation's energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting columns.

Generation's and ComEd's use of cash collateral is generally unrestricted unless Generation or ComEd are 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 meet certain qualifications.

Commodity Price Risk (All Registrants)

Each of the 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, including swaps, futures, forwards, options, and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Generation. To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels, and other commodities. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities and are subject to limits established by Exelon's RMC.

Utility Registrants. 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.
		Changes in fair value of economic hedge recorded to an offsetting regulatory asset or liability[b]	Exchange traded future contracts for up to 50% of estimated monthly purchase requirements each month, including purchases for storage injections.
ACE	Electricity	NPNS	Fixed price contracts for all BGS requirements through full requirements contracts.

(a) See Note 3 — Regulatory Matters of the 2020 Form 10-K for additional information.
(b) The fair value of the DPL economic hedge is not material as of September 30, 2021 and December 31, 2020 and is not presented in the fair value tables below.

The following tables provide a summary of the derivative fair value balances recorded by Exelon, Generation, and ComEd as of September 30, 2021 and December 31, 2020:

	Exelon	Generation					ComEd
September 30, 2021	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral[a][b]	Netting[a]	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	$ 1,505	$ 19,631	$ 63	$ (790)	$ (17,399)	$ 1,505	$ —
Mark-to-market derivative assets (noncurrent assets)	661	3,612	5	(201)	(2,755)	661	—
Total mark-to-market derivative assets	2,166	23,243	68	(991)	(20,154)	2,166	—
Mark-to-market derivative liabilities (current liabilities)	(1,710)	(18,490)	(55)	(559)	17,399	(1,705)	(5)
Mark-to-market derivative liabilities (noncurrent liabilities)	(720)	(3,168)	(3)	(95)	2,755	(511)	(209)
Total mark-to-market derivative liabilities	(2,430)	(21,658)	(58)	(654)	20,154	(2,216)	(214)
Total mark-to-market derivative net (liabilities) assets	$ (264)	$ 1,585	$ 10	$ (1,645)	$ —	$ (50)	$ (214)

	Exelon	Generation					ComEd
December 31, 2020	Total Derivatives	Economic Hedges	Proprietary Trading	Collateral[(a)(b)]	Netting[(a)]	Subtotal	Economic Hedges
Mark-to-market derivative assets (current assets)	$ 639	$ 2,757	$ 40	$ 103	$ (2,261)	$ 639	$ —
Mark-to-market derivative assets (noncurrent assets)	554	1,501	4	64	(1,015)	554	—
Total mark-to-market derivative assets	1,193	4,258	44	167	(3,276)	1,193	—
Mark-to-market derivative liabilities (current liabilities)	(293)	(2,629)	(23)	131	2,261	(260)	(33)
Mark-to-market derivative liabilities (noncurrent liabilities)	(472)	(1,335)	(2)	118	1,015	(204)	(268)
Total mark-to-market derivative liabilities	(765)	(3,964)	(25)	249	3,276	(464)	(301)
Total mark-to-market derivative net assets (liabilities)	$ 428	$ 294	$ 19	$ 416	$ —	$ 729	$ (301)

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance in the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit, and other forms of non-cash collateral. As of September 30, 2021, $1 million of cash collateral posted with external counterparties and an additional $71 million of cash collateral posted with affiliates, including $50 million with ComEd, and as of December 31, 2020, $15 million of cash collateral held with external counterparties, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, was associated with accrual positions, or had no positions to offset as of the balance sheet date.

(b) Includes $2,084 million held and $209 million posted of variation margin with the exchanges as of September 30, 2021 and December 31, 2020 respectively.

Economic Hedges (Commodity Price Risk)

Generation. For the three and nine months ended September 30, 2021 and 2020, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Income Statement Location	(Loss) Gain		(Loss) Gain	
Operating revenues	$ (637)	$ 39	$ (961)	$ 238
Purchased power and fuel	1,392	209	2,209	224
Total Exelon and Generation	$ 755	$ 248	$ 1,248	$ 462

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96%-99% for the remainder of 2021.

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed with the intent of hedging or managing risk. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income and are included in the Net fair value changes related to derivatives line in the Consolidated Statements of Cash Flows. For the three and nine months ended September 30, 2021 and 2020, net pre-tax commodity mark-to-market gains and losses for Exelon and Generation were not material. The Utility Registrants do not execute derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Generation utilizes interest rate swaps to manage its interest rate exposure and foreign currency derivatives to manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, both of which are treated as economic hedges. The notional amounts were $567 million and $665 million for Exelon and Generation as of September 30, 2021 and December 31, 2020, respectively.

The mark-to-market derivative assets and liabilities as of September 30, 2021 and December 31, 2020 and the mark-to-market gains and losses for the three and nine months ended September 30, 2021 and 2020 were not material for Exelon and Generation.

Credit Risk (All Registrants)

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.

Generation. For commodity derivatives, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds, and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The amounts in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX, and Nodal commodity exchanges.

Rating as of September 30, 2021	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 701	$ 254	$ 447	—	$ —
Non-investment grade	23	2	21	—	—
No external ratings					
Internally rated — investment grade	110	1	109	—	—
Internally rated — non-investment grade	309	48	261	—	—
Total	$ 1,143	$ 305	$ 838	—	$ —

Net Credit Exposure by Type of Counterparty	As of September 30, 2021
Financial institutions	$ 53
Investor-owned utilities, marketers, power producers	652
Energy cooperatives and municipalities	62
Other	71
Total	$ 838

(a) As of September 30, 2021, credit collateral held from counterparties where Generation had credit exposure included $188 million of cash and $117 million of letters of credit. The credit collateral does not include non-liquid collateral.

Utility Registrants. 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. As of September 30, 2021, the amount of cash collateral held with external counterparties by ComEd, BGE, and DPL was $56 million, $21 million, and $25 million, respectively, which is recorded in Other Current Liabilities in ComEd's, BGE's, and DPL's Consolidated Balance Sheets. The amounts for PECO, Pepco, and ACE as of September 30, 2021 and for the Utility Registrants as of December 31, 2020 are not material. The amount for ComEd as of September 30, 2021 does not include cash collateral held from Generation, which is disclosed in the notes to the derivative fair value balances tables above.

Credit-Risk-Related Contingent Features (All Registrants)

Generation. As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances, and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Features	**September 30, 2021**	**December 31, 2020**
Gross fair value of derivative contracts containing this feature[(a)]	$ (5,289)	$ (834)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	2,735	537
Net fair value of derivative contracts containing this feature[(c)]	$ (2,554)	$ (297)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which Generation could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

As of September 30, 2021 and December 31, 2020, Exelon and Generation posted or held the following amounts of cash collateral and letters of credit on derivative contracts with external counterparties, after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

	September 30, 2021	**December 31, 2020**
Cash collateral posted	$ 299	$ 511
Letters of credit posted	477	226
Cash collateral held	1,872	110
Letters of credit held	130	40
Additional collateral required in the event of a credit downgrade below investment grade	3,001	1,432

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded.

Utility Registrants

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 September 30, 2021, 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 September 30, 2021, they could have been required to post incremental collateral to their counterparties of $23 million, $46 million, and $11 million, respectively.

13. 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. Generation and PECO meet their 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.

Commercial Paper

The following table reflects the Registrants' commercial paper programs as of September 30, 2021 and December 31, 2020. PECO and BGE had no commercial paper borrowings as of September 30, 2021 and December 31, 2020.

	Outstanding Commercial Paper as of		Average Interest Rate on Commercial Paper Borrowings as of	
Commercial Paper Issuer	September 30, 2021	December 31, 2020	September 30, 2021	December 31, 2020
Exelon[(a)]	$ 287	$ 1,031	0.19 %	0.25 %
Generation	—	340	— %	0.27 %
ComEd	—	323	— %	0.23 %
PHI[(b)]	287	368	0.19 %	0.24 %
Pepco	40	35	0.15 %	0.22 %
DPL	22	146	0.15 %	0.24 %
ACE	225	187	0.20 %	0.25 %

(a) Exelon Corporate had no outstanding commercial paper borrowings as of September 30, 2021 and December 31, 2020.
(b) Represents the consolidated amounts of Pepco, DPL, and ACE.

See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on the Registrants' credit facilities.

Short-Term Loan Agreements

On March 23, 2017, Exelon Corporate entered into a term loan agreement for $500 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 24, 2021, Exelon Corporate entered into a 9-month term loan agreement for $200 million. The loan agreement has an expiration of December 24, 2021. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.65% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 31, 2021, Exelon Corporate entered into a 9-month and 364-day term loan agreement for $150 million each with variable interest rates of LIBOR plus 0.65% and expiration dates of December 31, 2021 and March 30, 2022, respectively. The loan agreements are reflected in Exelon's Consolidated Balance Sheets within Short-term borrowings.

On March 19, 2020, Generation entered into a term loan agreement for $200 million. The loan agreement was renewed on March 17, 2021 and will expire on March 16, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.875% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's and Generation's Consolidated Balance Sheets within Short-term borrowings.

On March 31, 2020, Generation entered into a term loan agreement for $300 million. The loan agreement was renewed on March 30, 2021 and will expire on March 29, 2022. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.70% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's and Generation's Consolidated Balance Sheets within Short-term borrowings.

On August 6, 2021, Generation entered into a 364-day term loan agreement for $880 million with a variable interest rate of LIBOR plus 0.875% until March 31, 2022 and a rate of LIBOR plus 1% thereafter and all indebtedness thereunder is unsecured. The loan agreement has an expiration date of August 5, 2022 and is reflected in Short-term borrowings in Exelon's and Generation's Consolidated Balance Sheets.

On January 25, 2021, ComEd entered into two 90-day term loan agreements for $125 million each with variable interest rates of LIBOR plus 0.50% and LIBOR plus 0.75%, respectively. ComEd repaid the term loans on March 9, 2021.

Bilateral Credit Agreements

On January 11, 2013, Generation entered into a bilateral credit agreement for $100 million. The agreement was renewed on March 1, 2021 with a maturity date of March 1, 2023.

On February 21, 2019, Generation entered into a bilateral credit agreement for $100 million. The agreement was renewed on March 31, 2021 with a maturity date of March 31, 2022.

On January 5, 2016, Generation entered into a bilateral credit agreement for $150 million. The agreement was renewed on April 2, 2021 with a maturity date of April 5, 2023.

On October 26, 2012, Generation entered into a bilateral credit agreement for $200 million. The agreement had a maturity date of October 22, 2021, however, was terminated on August 27, 2021.

See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on Generation's bilateral credit agreements.

Credit Agreements

On July 15, 2021, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2024.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2021, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Long-Term Software License Agreements	3.62 %	December 1, 2025	$ 4	Procurement of software licenses.
Generation	West Medway II Nonrecourse Debt	LIBOR + 3% [(a)]	March 31, 2026	150	Funding for general corporate purposes.
Generation	Energy Efficiency Project Financing[(b)]	2.53 %	November 30, 2021	1	Funding to install energy conservation measures for the Fort AP Hill project.
Generation	Energy Efficiency Project Financing[(b)]	4.24 %	November 30, 2021	1	Funding to install energy conservation measures for the Marine Corps. Logistics Project.
ComEd	First Mortgage Bonds, Series 130	3.13 %	March 15, 2051	700	Repay a portion of outstanding commercial paper obligations and two outstanding term loans, and to fund other general corporate purposes.
ComEd	First Mortgage Bonds, Series 131	2.75 %	September 1, 2051	450	Refinance existing indebtedness and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.05 %	March 15, 2051	375	Funding for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	2.85 %	September 15, 2051	375	Refinance existing indebtedness and for general corporate purposes.
BGE	Senior Notes	2.25 %	June 15, 2031	600	Repay a portion of outstanding commercial paper obligations, repay existing indebtedness, and to fund other general corporate purposes.
Pepco	First Mortgage Bonds	2.32 %	March 30, 2031	150	Repay existing indebtedness and for general corporate purposes.
Pepco	First Mortgage Bonds	3.29 %	September 28, 2051	125	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	3.24 %	March 30, 2051	125	Repay existing indebtedness and for general corporate purposes.
ACE	First Mortgage Bonds	2.30 %	March 15, 2031	350	Refinance existing indebtedness, repay outstanding commercial paper obligations, and for general corporate purposes.

(a) The nonrecourse debt has an average blended interest rate.
(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

Debt Covenants

As of September 30, 2021, the Registrants are in compliance with debt covenants.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default.

West Medway II, LLC. On May 13, 2021, West Medway II, LLC (West Medway II), an indirect subsidiary of Generation, entered into a financing agreement for a $150 million nonrecourse senior secured term loan credit facility with a maturity date of March 31, 2026. The term loan bears interest at an average blended interest rate of

LIBOR plus 3%, paid quarterly. In addition to the financing, West Medway II, entered into interest rate swaps with an initial notional amount of $113 million at an interest rate of 0.61%, paid quarterly, to manage a portion of the interest rate exposure in connection with the financing. The net proceeds were distributed to Generation for general corporate purposes. Generation's interests in West Medway II, were pledged as collateral for this financing. As of September 30, 2021, approximately $145 million was outstanding.

See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on nonrecourse debt and Note 12 — Derivative Financial Instruments for additional information on interest rate swaps.

14. Fair Value of Financial Assets and Liabilities (All Registrants)

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

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

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, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of September 30, 2021 and December 31, 2020. The Registrants have no financial liabilities classified as Level 1.

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.

	September 30, 2021				December 31, 2020			
		Fair Value				Fair Value		
	Carrying Amount	Level 2	Level 3	Total	Carrying Amount	Level 2	Level 3	Total
Long-Term Debt, including amounts due within one year[(a)]								
Exelon	$ 38,644	$ 40,570	$ 3,289	$ 43,859	$ 36,912	$ 40,688	$ 3,064	$ 43,752
Generation	6,130	5,835	1,111	6,946	6,087	5,648	1,208	6,856
ComEd	9,772	11,344	—	11,344	8,983	11,117	—	11,117
PECO	4,196	4,738	50	4,788	3,753	4,553	50	4,603
BGE	3,960	4,416	—	4,416	3,664	4,366	—	4,366
PHI	7,482	6,030	2,128	8,158	7,006	6,099	1,806	7,905
Pepco	3,441	3,226	990	4,216	3,165	3,336	748	4,084
DPL	1,808	1,433	559	1,992	1,677	1,484	455	1,939
ACE	1,510	1,107	579	1,686	1,413	1,018	602	1,620
Long-Term Debt to Financing Trusts[(a)]								
Exelon	$ 390	$ —	$ 479	$ 479	$ 390	$ —	$ 467	$ 467
ComEd	205	—	255	255	205	—	246	246
PECO	184	—	224	224	184	—	221	221
SNF Obligation								
Exelon	$ 1,209	$ 1,021	$ —	$ 1,021	$ 1,208	$ 909	$ —	$ 909
Generation	1,209	1,021	—	1,021	1,208	909	—	909

(a) Includes unamortized debt issuance costs which are not fair valued.

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 as of September 30, 2021 and December 31, 2020:

Exelon and Generation

	Exelon					Generation				
As of September 30, 2021	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents(a)	$ 2,573	$ —	$ —	$ —	$ 2,573	$ 1,673	$ —	$ —	$ —	$ 1,673
NDT fund investments										
Cash equivalents(b)	647	135	—	—	782	647	135	—	—	782
Equities	4,373	1,717	1	1,559	7,650	4,373	1,717	1	1,559	7,650
Fixed income										
Corporate debt(c)	—	1,155	287	—	1,442	—	1,155	287	—	1,442
U.S. Treasury and agencies	2,192	29	—	—	2,221	2,192	29	—	—	2,221
Foreign governments	—	54	—	—	54	—	54	—	—	54
State and municipal debt	—	29	—	—	29	—	29	—	—	29
Other	31	29	—	1,259	1,319	31	29	—	1,259	1,319
Fixed income subtotal	2,223	1,296	287	1,259	5,065	2,223	1,296	287	1,259	5,065
Private credit	—	—	187	592	779	—	—	187	592	779
Private equity	—	—	—	654	654	—	—	—	654	654
Real estate	—	—	—	802	802	—	—	—	802	802
NDT fund investments subtotal(d)(e)	7,243	3,148	475	4,866	15,732	7,243	3,148	475	4,866	15,732
Rabbi trust investments										
Cash equivalents	65	—	—	—	65	4	—	—	—	4
Mutual funds	104	—	—	—	104	35	—	—	—	35
Fixed income	—	10	—	—	10	—	—	—	—	—
Life insurance contracts	—	99	34	—	133	—	33	—	—	33
Rabbi trust investments subtotal	169	109	34	—	312	39	33	—	—	72
Investments in equities(f)	137	—	—	—	137	137	—	—	—	137
Commodity derivative assets										
Economic hedges	5,527	10,633	7,083	—	23,243	5,527	10,633	7,083	—	23,243
Proprietary trading	—	56	12	—	68	—	56	12	—	68
Effect of netting and allocation of collateral(g)(h)	(4,468)	(9,869)	(6,808)	—	(21,145)	(4,468)	(9,869)	(6,808)	—	(21,145)
Commodity derivative assets subtotal	1,059	820	287	—	2,166	1,059	820	287	—	2,166
DPP consideration	—	501	—	—	501	—	501	—	—	501

	Exelon					Generation				
As of September 30, 2021	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Total assets	11,181	4,578	796	4,866	21,421	10,151	4,502	762	4,866	20,281
Liabilities										
Commodity derivative liabilities										
Economic hedges	(4,126)	(9,192)	(8,554)	—	(21,872)	(4,126)	(9,192)	(8,340)	—	(21,658)
Proprietary trading	—	(32)	(26)	—	(58)	—	(32)	(26)	—	(58)
Effect of netting and allocation of collateral[g][h]	4,123	9,159	6,218	—	19,500	4,123	9,159	6,218	—	19,500
Commodity derivative liabilities subtotal	(3)	(65)	(2,362)	—	(2,430)	(3)	(65)	(2,148)	—	(2,216)
Deferred compensation obligation	—	(149)	—	—	(149)	—	(44)	—	—	(44)
Total liabilities	(3)	(214)	(2,362)	—	(2,579)	(3)	(109)	(2,148)	—	(2,260)
Total net assets (liabilities)	$ 11,178	$ 4,364	$ (1,566)	$ 4,866	$ 18,842	$ 10,148	$ 4,393	$ (1,386)	$ 4,866	$ 18,021

	Exelon					Generation				
As of December 31, 2020	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[a]	$ 686	$ —	$ —	$ —	$ 686	$ 124	$ —	$ —	$ —	$ 124
NDT fund investments										
Cash equivalents[b]	210	95	—	—	305	210	95	—	—	305
Equities	3,886	2,077	—	1,562	7,525	3,886	2,077	—	1,562	7,525
Fixed income										
Corporate debt[c]	—	1,485	285	—	1,770	—	1,485	285	—	1,770
U.S. Treasury and agencies	1,871	126	—	—	1,997	1,871	126	—	—	1,997
Foreign governments	—	56	—	—	56	—	56	—	—	56
State and municipal debt	—	101	—	—	101	—	101	—	—	101
Other	—	41	—	961	1,002	—	41	—	961	1,002
Fixed income subtotal	1,871	1,809	285	961	4,926	1,871	1,809	285	961	4,926
Private credit	—	—	212	629	841	—	—	212	629	841
Private equity	—	—	—	504	504	—	—	—	504	504
Real estate	—	—	—	679	679	—	—	—	679	679
NDT fund investments subtotal[d][e]	5,967	3,981	497	4,335	14,780	5,967	3,981	497	4,335	14,780
Rabbi trust investments										
Cash equivalents	60	—	—	—	60	4	—	—	—	4
Mutual funds	91	—	—	—	91	29	—	—	—	29
Fixed income	—	11	—	—	11	—	—	—	—	—
Life insurance contracts	—	87	34	—	121	—	28	—	—	28
Rabbi trust investments subtotal	151	98	34	—	283	33	28	—	—	61
Investments in equities[f]	195	—	—	—	195	195	—	—	—	195
Commodity derivative assets										
Economic hedges	745	1,914	1,599	—	4,258	745	1,914	1,599	—	4,258
Proprietary trading	—	17	27	—	44	—	17	27	—	44

	Exelon					Generation				
As of December 31, 2020	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Effect of netting and allocation of collateral[(g)(h)]	(607)	(1,597)	(905)	—	(3,109)	(607)	(1,597)	(905)	—	(3,109)
Commodity derivative assets subtotal	138	334	721	—	1,193	138	334	721	—	1,193
DPP consideration	—	639	—	—	639	—	639	—	—	639
Total assets	7,137	5,052	1,252	4,335	17,776	6,457	4,982	1,218	4,335	16,992
Liabilities										
Commodity derivative liabilities										
Economic hedges	(682)	(1,928)	(1,655)	—	(4,265)	(682)	(1,928)	(1,354)	—	(3,964)
Proprietary trading	—	(21)	(4)	—	(25)	—	(21)	(4)	—	(25)
Effect of netting and allocation of collateral[(g)(h)]	540	1,918	1,067	—	3,525	540	1,918	1,067	—	3,525
Commodity derivative liabilities subtotal	(142)	(31)	(592)	—	(765)	(142)	(31)	(291)	—	(464)
Deferred compensation obligation	—	(145)	—	—	(145)	—	(42)	—	—	(42)
Total liabilities	(142)	(176)	(592)	—	(910)	(142)	(73)	(291)	—	(506)
Total net assets	$ 6,995	$ 4,876	$ 660	$ 4,335	$ 16,866	$ 6,315	$ 4,909	$ 927	$ 4,335	$ 16,486

(a) Exelon excludes cash of $689 million and $409 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $222 million and $59 million at September 30, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of $54 million and $53 million at September 30, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Generation excludes cash of $292 million and $171 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $54 million and $20 million at September 30, 2021 and December 31, 2020, respectively.

(b) Includes $109 million and $116 million of cash received from outstanding repurchase agreements at September 30, 2021 and December 31, 2020, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (e) below.

(c) Includes investments in equities sold short of $(50) million and $(62) million as of September 30, 2021 and December 31, 2020, respectively, held in an investment vehicle primarily to hedge the equity option component of its convertible debt.

(d) Includes net derivative liabilities of less than $1 million and net derivative assets of $2 million, which have total notional amounts of $728 million and $1,043 million at September 30, 2021 and December 31, 2020, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.

(e) Excludes net liabilities of $130 million and $181 million at September 30, 2021 and December 31, 2020, respectively, which include certain derivative assets that have notional amounts of $194 million and $104 million at September 30, 2021 and December 31, 2020, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(f) Includes equity investments held by Generation which were previously designated as equity investments without readily determinable fair value but are now publicly traded and therefore have readily determinable fair values. The first investment became publicly traded in the fourth quarter of 2020. Generation records the fair value of these investments in Other current assets in Exelon's and Generation's Consolidated Balance Sheets based on the quoted market prices of the stocks as of the respective balance sheet date. There were no equity investments without readily determinable fair value that became publicly traded during the third quarter of 2021. For investments that became publicly traded during the first half of 2021, unrealized gains of $220 million were recorded in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

(g) Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $(345) million, $(710) million, and $(590) million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of September 30, 2021. Collateral (received)/posted from counterparties, net of collateral paid to counterparties, totaled $(67) million, $321 million, and $162 million allocated to Level 1, Level 2, and Level 3 mark-to-market derivatives, respectively, as of December 31, 2020.

(h) Includes $2,084 million held and $209 million posted of variation margin with the exchanges as of September 30, 2021 and December 31, 2020, respectively.

As of September 30, 2021, Exelon and Generation have outstanding commitments to invest in private credit, private equity, and real estate investments of approximately $359 million, $174 million, and $371 million, respectively. These commitments will be funded by Generation’s existing NDT funds.

Exelon and Generation held investments without readily determinable fair values with carrying amounts of $44 million and $32 million as of September 30, 2021, respectively. Exelon and Generation held investments without readily determinable fair values with carrying amounts of $73 million and $55 million as of December 31, 2020, respectively. Changes in fair value, cumulative adjustments, and impairments were not material for the three and nine months ended September 30, 2021 and for the year ended December 31, 2020.

ComEd, PECO, and BGE

	ComEd				PECO				BGE			
As of September 30, 2021	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)	$ 309	$ —	$ —	$ 309	$ 247	$ —	$ —	$ 247	$ 169	$ —	$ —	$ 169
Rabbi trust investments												
Mutual funds	—	—	—	—	10	—	—	10	14	—	—	14
Life insurance contracts	—	—	—	—	—	15	—	15	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	10	15	—	25	14	—	—	14
Total assets	309	—	—	309	257	15	—	272	183	—	—	183
Liabilities												
Deferred compensation obligation	—	(9)	—	(9)	—	(8)	—	(8)	—	(6)	—	(6)
Mark-to-market derivative liabilities(b)	—	—	(214)	(214)	—	—	—	—	—	—	—	—
Total liabilities	—	(9)	(214)	(223)	—	(8)	—	(8)	—	(6)	—	(6)
Total net assets (liabilities)	$ 309	$ (9)	$ (214)	$ 86	$ 257	$ 7	$ —	$ 264	$ 183	$ (6)	$ —	$ 177

	ComEd				PECO				BGE			
As of December 31, 2020	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)	$ 285	$ —	$ —	$ 285	$ 8	$ —	$ —	$ 8	$ 120	$ —	$ —	$ 120
Rabbi trust investments												
Mutual funds	—	—	—	—	9	—	—	9	10	—	—	10
Life insurance contracts	—	—	—	—	—	13	—	13	—	—	—	—
Rabbi trust investments subtotal	—	—	—	—	9	13	—	22	10	—	—	10
Total assets	285	—	—	285	17	13	—	30	130	—	—	130
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(9)	—	(9)	—	(5)	—	(5)
Mark-to-market derivative liabilities(b)	—	—	(301)	(301)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(301)	(309)	—	(9)	—	(9)	—	(5)	—	(5)
Total net assets (liabilities)	$ 285	$ (8)	$ (301)	$ (24)	$ 17	$ 4	$ —	$ 21	$ 130	$ (5)	$ —	$ 125

(a) ComEd excludes cash of $145 million and $83 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $107 million and $37 million at September 30, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of $44 million and $43 million at September 30, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $105 million and $18 million at September 30, 2021 and December 31, 2020, respectively. BGE excludes cash of $56 million and $24 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $27 million and $1 million at September 30, 2021 and December 31, 2020, respectively.

(b) The Level 3 balance consists of the current and noncurrent liability of $5 million and $209 million, respectively, at September 30, 2021 and $33 million and $268 million, respectively, at December 31, 2020 related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

PHI, Pepco, DPL, and ACE

	As of September 30, 2021				As of December 31, 2020			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 100	$ —	$ —	$ 100	$ 86	$ —	$ —	$ 86
Rabbi trust investments								
Cash equivalents	59	—	—	59	55	—	—	55
Mutual funds	14	—	—	14	14	—	—	14
Fixed income	—	10	—	10	—	11	—	11
Life insurance contracts	—	27	34	61	—	26	34	60
Rabbi trust investments subtotal	73	37	34	144	69	37	34	140
Total assets	173	37	34	244	155	37	34	226
Liabilities								
Deferred compensation obligation	—	(19)	—	(19)	—	(17)	—	(17)
Total liabilities	—	(19)	—	(19)	—	(17)	—	(17)
Total net assets	$ 173	$ 18	$ 34	$ 225	$ 155	$ 20	$ 34	$ 209

	Pepco				DPL				ACE			
As of September 30, 2021	**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)]	$ 36	$ —	$ —	$ 36	$ 26	$ —	$ —	$ 26	$ 14	$ —	$ —	$ 14
Rabbi trust investments												
Cash equivalents	58	—	—	58	—	—	—	—	—	—	—	—
Fixed income	—	—	—	—	—	—	—	—	—	—	—	—
Life insurance contracts	—	27	34	61	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	58	27	34	119	—	—	—	—	—	—	—	—
Total assets	94	27	34	155	26	—	—	26	14	—	—	14
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	$ 94	$ 25	$ 34	$ 153	$ 26	$ —	$ —	$ 26	$ 14	$ —	$ —	$ 14

	Pepco				DPL				ACE			
As of December 31, 2020	**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)]	$ 35	$ —	$ —	$ 35	$ —	$ —	$ —	$ —	$ 13	$ —	$ —	$ 13
Rabbi trust investments												
Cash equivalents	53	—	—	53	—	—	—	—	—	—	—	—
Fixed income	—	2	—	2	—	—	—	—	—	—	—	—
Life insurance contracts	—	26	34	60	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal	53	28	34	115	—	—	—	—	—	—	—	—
Total assets	88	28	34	150	—	—	—	—	13	—	—	13
Liabilities												
Deferred compensation obligation	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total liabilities	—	(2)	—	(2)	—	—	—	—	—	—	—	—
Total net assets	$ 88	$ 26	$ 34	$ 148	$ —	$ —	$ —	$ —	$ 13	$ —	$ —	$ 13

(a) PHI excludes cash of $57 million and $74 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $5 million and none at September 30, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of $9 million and $10 million at September 30, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of $19 million and $30 million at September 30, 2021 and December 31, 2020, respectively, and restricted cash of $5 million and none at September 30, 2021 and December 31, 2020, respectively. DPL excludes cash of $13 million and $15 million at September 30, 2021 and December 31, 2020, respectively. ACE excludes cash of $16 million and $17 million at September 30, 2021 and December 31, 2020, respectively, and includes long-term restricted cash of $9 million and $10 million at September 30, 2021 and December 31, 2020, respectively, which is reported in Other deferred debits in the Consolidated Balance Sheets.

Reconciliation of Level 3 Assets and Liabilities

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2021 and 2020:

	Exelon	Generation			ComEd	PHI and Pepco	
Three Months Ended September 30, 2021	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of June 30, 2021	$ (235)	$ 461	$ (465)	$ (4)	$ (265)	$ 34	$ —
Total realized / unrealized gains (losses)							
Included in net income	(967)	3	(970) [(a)]	(967)	—	—	—
Included in noncurrent payables to affiliates	—	11	—	11	—	—	(11)
Included in regulatory assets	62	—	—	—	51 [(b)]	—	11
Change in collateral	(413)	—	(413)	(413)	—	—	—
Purchases, sales, and settlements							
Purchases	8	2	6	8	—	—	—
Sales	6	—	6	6	—	—	—
Settlements	(2)	(2)	—	(2)	—	—	—
Transfers into Level 3	2	—	2 [(c)]	2	—	—	—
Transfers out of Level 3	(27)	—	(27) [(c)]	(27)	—	—	—
Balance at September 30, 2021	$ (1,566)	$ 475	$ (1,861)	$ (1,386)	$ (214)	$ 34	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2021	$ (1,001)	$ 3	$ (1,004)	$ (1,001)	$ —	$ —	$ —

	Exelon	Generation			ComEd	PHI and Pepco	
Nine months ended September 30, 2021	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of December 31, 2020	$ 660	$ 497	$ 430	$ 927	$ (301)	$ 34	$ —
Total realized / unrealized gains (losses)							
Included in net income	(1,600)	4	(1,606) (a)	(1,602)	—	2	—
Included in noncurrent payables to affiliates	—	18	—	18	—	—	(18)
Included in regulatory assets	105	—	—	—	87 (b)	—	18
Change in collateral	(751)	—	(751)	(751)	—	—	—
Purchases, sales, and settlements							
Purchases	123	3	120	123	—	—	—
Sales	7	—	7	7	—	—	—
Settlements	(50)	(48)	—	(48)	—	(2)	—
Transfers into Level 3	4	1	3 (c)	4	—	—	—
Transfers out of Level 3	(64)	—	(64) (c)	(64)	—	—	—
Balance as of September 30, 2021	$ (1,566)	$ 475	$ (1,861)	$ (1,386)	$ (214)	$ 34	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2021	$ (1,521)	$ 4	$ (1,527)	$ (1,523)	$ —	$ 2	$ —

	Exelon	Generation			ComEd	PHI and Pepco	
Three Months Ended September 30, 2020	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of June 30, 2020	$ 883	$ 499	$ 659	$ 1,158	$ (318)	$ 43	$ —
Total realized / unrealized gains (losses)							
Included in net income	(327)	3	(318) (a)	(315)	—	(12)	—
Included in noncurrent payables to affiliates	—	18	—	18	—	—	(18)
Included in regulatory assets/liabilities	32	—	—	—	14 (b)	—	18
Change in collateral	(79)	—	(79)	(79)	—	—	—
Purchases, sales, and settlements							
Purchases	66	1	65	66	—	—	—
Sales	(3)	—	(3)	(3)	—	—	—
Settlements	—	(3)	—	(3)	—	3	—
Transfers out of Level 3	9	—	9 (c)	9	—	—	—
Balance as of September 30, 2020	$ 581	$ 518	$ 333	$ 851	$ (304)	$ 34	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2020	$ (222)	$ 3	$ (213)	$ (210)	$ —	$ (12)	$ —

	Exelon	Generation			ComEd	PHI and Pepco	
Nine Months Ended September 30, 2020	Total	NDT Fund Investments	Mark-to-Market Derivatives	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation
Balance as of December 31, 2019	$ 1,068	$ 511	$ 817	$ 1,328	$ (301)	$ 41	$ —
Total realized / unrealized gains (losses)							
Included in net income	(483)	1	(474) (a)	(473)	—	(10)	—
Included in noncurrent payables to affiliates	—	17	—	17	—	—	(17)
Included in regulatory assets	14	—	—	—	(3) (b)	—	17
Change in collateral	(120)	—	(120)	(120)	—	—	—
Purchases, sales, and settlements							
Purchases	136	6	130	136	—	—	—
Sales	(27)	—	(27)	(27)	—	—	—
Settlements	(15)	(18)	—	(18)	—	3	—
Transfers into Level 3	(5)	1	(6) (c)	(5)	—	—	—
Transfers out of Level 3	13	—	13 (c)	13	—	—	—
Balance as of September 30, 2020	$ 581	$ 518	$ 333	$ 851	$ (304)	$ 34	$ —
The amount of total (losses) gains included in income attributed to the change in unrealized (losses) gains related to assets and liabilities as of September 30, 2020	$ (107)	$ 1	$ (98)	$ (97)	$ —	$ (10)	$ —

(a) Includes an addition of $34 million for realized losses and a reduction of $80 million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2021. Includes a reduction of $105 million and $376 million for realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2020.

(b) Includes $49 million of increases in fair value and an increase for realized losses due to settlements of $2 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2021. Includes $72 million of increases in fair value and an increase for realized losses due to settlements of $15 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the nine months ended September 30, 2021. Includes $9 million of increases in fair value and an increase for realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2020. Includes $26 million of decrease in fair value and an increase for realized losses due to settlements of $23 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the nine months ended September 30, 2020.

(c) Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2021 and 2020:

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total (losses) gains included in net income for the three months ended September 30, 2021	$ (1,274)	$ 304	$ —	$ 3	$ (1,274)	$ 304	$ 3	$ —
Total (losses) gains included in net income for the nine months ended September 30, 2021	(1,944)	338	2	4	(1,944)	338	4	2
Total unrealized (losses) gains for the three months ended September 30, 2021	(1,361)	357	—	3	(1,361)	357	3	—
Total unrealized (losses) gains for the nine months ended September 30, 2021	(1,969)	443	2	4	(1,969)	443	4	2

	Exelon				Generation			PHI and Pepco
	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance
Total losses included in net income for the three months ended September 30, 2020	$ (305)	$ (13)	$ (12)	$ —	$ (305)	$ (13)	$ —	$ (12)
Total losses included in net income for the nine months ended September 30, 2020	(370)	(104)	(10)	—	(370)	(104)	—	(10)
Total unrealized (losses) gains for the three months ended September 30, 2020	(216)	3	(12)	3	(216)	3	3	(12)
Total unrealized gains (losses) for the nine months ended September 30, 2020	(50)	(48)	(10)	1	(50)	(48)	1	(10)

Valuation Techniques Used to Determine Fair Value

Exelon's valuation techniques used to measure the fair value of the assets and liabilities shown in the tables below are in accordance with the policies discussed in Note 18 — Fair Value of Financial Assets and Liabilities of the Exelon 2020 Form 10-K.

Valuation Techniques Used to Determine Net asset Value (Exelon and Generation)

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

For commingled funds and mutual funds, which are not publicly quoted, the fair value is primarily derived from the quoted prices in active markets on the underlying securities and can typically be redeemed monthly with 30 or less days of notice and without further restrictions. For managed private credit funds, the fair value is determined using a combination of valuation models including cost models, market models, and income models and typically cannot be redeemed until maturity of the term loan. Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date, which is based on Exelon's understanding of the investment funds. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are unobservable.

Mark-to-Market Derivatives (Exelon, Generation, and ComEd)

The table below discloses the significant inputs to the forward curve used to value mark-to-market derivatives.

Type of trade	Fair Value at September 30, 2021	Fair Value at December 31, 2020	Valuation Technique	Unobservable Input	2021 Range & Arithmetic Average				2020 Range & Arithmetic Average			
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[a][b]	$ (1,257)	$ 245	Discounted Cash Flow	Forward power price	$9.77	-	$301	$55	$2.25	-	$163	$30
				Forward gas price	$1.76	-	$23.00	$4.16	$1.57	-	$7.88	$2.59
			Option Model	Volatility percentage	35%	-	197%	49%	11%	-	237%	32%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[a][b]	$ (14)	$ 23	Discounted Cash Flow	Forward power price	$16	-	$156	$53	$10	-	$106	$27
Mark-to-market derivatives (Exelon and ComEd)	$ (214)	$ (301)	Discounted Cash Flow	Forward heat rate[c]	9x	-	10x	9.13x	8x	-	9x	8.85x
				Marketability reserve	3%	-	7%	4.77%	3%	-	8%	4.93%
				Renewable factor	95%	-	122%	100%	91%	-	123%	99%

(a) The valuation techniques, unobservable inputs, ranges and arithmetic averages are the same for the asset and liability positions.
(b) The fair values do not include cash collateral (received)/posted on level three positions of $(590) million and $162 million as of September 30, 2021 and December 31, 2020, respectively.
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

The inputs listed above, which are as of the balance sheet date, would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

15. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 19 — Commitments and Contingencies of the Exelon 2020 Form 10-K.

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 as of September 30, 2021:

Description	Exelon	PHI	Pepco	DPL	ACE
Total commitments	$ 513	$ 320	$ 120	$ 89	$ 111
Remaining commitments[(a)]	74	62	51	7	4

(a) Remaining commitments extend through 2026 and include rate credits, energy efficiency programs and delivery system modernization.

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia, and Delaware at an estimated cost of approximately $135 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be primarily capital in nature, are recognized as incurred and recorded in Exelon's and Generation's financial statements. As of September 30, 2021, approximately 33 MWs of new generation were developed and Exelon and Generation have incurred costs of $121 million. Approximately 30 MWs of the new generation developed was part of Generation's first quarter 2021 sale of a significant portion of its solar business. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the solar business. Exelon has also committed to purchase 100 MWs of wind energy in PJM. DPL has committed to conducting three RFPs to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three wind REC RFPs. The first 40 MW wind REC tranche was conducted in 2017 and did not result in a purchase agreement. The second 40 MW wind REC tranche was conducted in 2018 and resulted in a proposed REC purchase agreement that was approved by the DPSC in 2019. The third and final 40 MW wind REC tranche will be conducted in 2022.

Commercial Commitments (All Registrants). The Registrants' commercial commitments as of September 30, 2021, representing commitments potentially triggered by future events were as follows:

		Expiration within					
	Total	2021	2022	2023	2024	2025	2026 and beyond
Exelon							
Letters of credit	$ 2,241	$ 268	$ 1,860	$ 113	$ —	$ —	$ —
Surety bonds[a]	971	403	566	—	2	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values[b]	31	—	3	3	6	6	13
Total commercial commitments	$ 3,621	$ 671	$ 2,429	$ 116	$ 8	$ 6	$ 391
Generation							
Letters of credit	$ 2,223	$ 264	$ 1,846	$ 113	$ —	$ —	$ —
Surety bonds[a]	826	352	474	—	—	—	—
Total commercial commitments	$ 3,049	$ 616	$ 2,320	$ 113	$ —	$ —	$ —
ComEd							
Letters of credit	$ 7	$ 2	$ 5	$ —	$ —	$ —	$ —
Surety bonds[a]	17	5	10	—	2	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$ 224	$ 7	$ 15	$ —	$ 2	$ —	$ 200
PECO							
Letters of credit	$ 1	$ —	$ 1	$ —	$ —	$ —	$ —
Surety bonds[a]	2	—	2	—	—	—	—
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$ 181	$ —	$ 3	$ —	$ —	$ —	$ 178
BGE							
Letters of credit	$ 2	$ —	$ 2	$ —	$ —	$ —	$ —
Surety bonds[a]	3	2	1	—	—	—	—
Total commercial commitments	$ 5	$ 2	$ 3	$ —	$ —	$ —	$ —
PHI							
Surety bonds[a]	$ 23	$ 3	$ 20	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	31	—	3	3	6	6	13
Total commercial commitments	$ 54	$ 3	$ 23	$ 3	$ 6	$ 6	$ 13
Pepco							
Surety bonds[a]	$ 14	$ —	$ 14	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	10	—	1	1	2	2	4
Total commercial commitments	$ 24	$ —	$ 15	$ 1	$ 2	$ 2	$ 4
DPL							
Surety bonds[a]	$ 5	$ 2	$ 3	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	13	—	1	1	3	3	5
Total commercial commitments	$ 18	$ 2	$ 4	$ 1	$ 3	$ 3	$ 5
ACE							
Surety bonds[a]	$ 4	$ 1	$ 3	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	8	—	1	1	1	1	4
Total commercial commitments	$ 12	$ 1	$ 4	$ 1	$ 1	$ 1	$ 4

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

(b) 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 $75 million guaranteed by Exelon and PHI, of which $25 million, $32 million, and $18 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 (Exelon and the Utility 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 almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

- ComEd has 21 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 2027.
- 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 2023.
- 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 2023.
- 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 settlements of natural gas distribution rate cases with the PAPUC, 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.

As of September 30, 2021 and December 31, 2020, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities in their respective Consolidated Balance Sheets:

	September 30, 2021		December 31, 2020	
	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	$ 474	$ 310	$ 483	$ 314
Generation	119	—	121	—
ComEd	284	284	293	293
PECO	23	21	23	21
BGE	6	5	2	—
PHI	42	—	44	—
Pepco	40	—	42	—
DPL	1	—	1	—
ACE	1	—	1	—

Cotter Corporation (Exelon and Generation). The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. In 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon’s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. Including Cotter, there are three PRPs participating in the West Lake Landfill remediation proceeding. Investigation by Generation has identified a number of other parties who also may be PRPs and could be liable to contribute to the final remedy. Further investigation is ongoing.

In September 2018, the EPA issued its Record of Decision Amendment (RODA) for the selection of a final remedy. The RODA modified the remedy previously selected by EPA in its 2008 Record of Decision (ROD). While the ROD required only that the radiological materials and other wastes at the site be capped, the 2018 RODA requires partial excavation of the radiological materials in addition to the previously selected capping remedy. The RODA also allows for variation in depths of excavation depending on radiological concentrations. The EPA and the PRPs have entered into a Consent Agreement to perform the Remedial Design, which is expected to be completed in late 2024. In March 2019 the PRPs received Special Notice Letters from the EPA to perform the Remedial Action work. On October 8, 2019, Cotter (Generation’s indemnitee) provided a non-binding good faith offer to conduct, or finance, a portion of the remedy, subject to certain conditions. The total estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred collectively by the PRPs in fully executing the remedy, is approximately $290 million, including cost escalation on an undiscounted basis, which would be allocated among the final group of PRPs. Generation has determined that a loss associated with the EPA’s partial excavation and enhanced landfill cover remedy is probable and has recorded a liability included in the table above, that reflects management’s best estimate of Cotter’s allocable share of the ultimate cost. Given the joint and several nature of this liability, the magnitude of Generation’s ultimate liability will depend on the actual costs incurred to implement the required remedy as well as on the nature and terms of any cost-sharing arrangements with the final group of PRPs. Therefore, it is reasonably possible that the ultimate cost and Cotter's associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact in Exelon's and Generation's future financial statements.

One of the other PRPs has indicated it will be making a contribution claim against Cotter for costs that it has incurred to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Exelon and Generation do not possess sufficient information to assess this claim and therefore are unable to estimate a range of loss, if any. As such, no liability has been recorded for the potential contribution claim. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact in Exelon’s and Generation's financial statements.

In January 2018, the PRPs were advised by the EPA that it will begin an additional investigation and evaluation of groundwater conditions at the West Lake Landfill. In September 2018, the PRPs agreed to an Administrative

Settlement Agreement and Order on Consent for the performance by the PRPs of the groundwater Remedial Investigation and Feasibility Study (RI/FS). The purpose of this RI/FS is to define the nature and extent of any groundwater contamination from the West Lake Landfill site and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS to be approximately $40 million. Generation determined a loss associated with the RI/FS is probable and has recorded a liability included in the table above that reflects management's best estimate of Cotter's allocable share of the cost among the PRPs. At this time Generation cannot predict the likelihood or the extent to which, if any, remediation activities may be required and therefore cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact in Exelon's and Generation's future financial statements.

In August 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's (now Generation's) indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. Government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under FUSRAP. Pursuant to a series of annual agreements since 2011, the DOJ and the PRPs have tolled the statute of limitations until February 28, 2022 so that settlement discussions can proceed. On August 3, 2020, the DOJ advised Cotter and the other PRPs that it is seeking approximately $90 million from all the PRPs and has directed that the PRPs must submit a good faith joint proposed settlement offer. At this time, the DOJ has stayed their request for a good faith offer while the parties review cost documentation associated with the cost claim. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

Benning Road Site (Exelon, Generation, 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 was formerly the location of a Pepco Energy Services electric generating facility, which 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 with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River.

Since 2013, Pepco and Pepco Energy Services (now Generation, pursuant to Exelon's 2016 acquisition of PHI) have been performing RI work and have submitted multiple draft RI reports to the DOEE. In September 2019, Pepco and Generation issued a draft “final” RI report which DOEE approved on February 3, 2020. Pepco and Generation are developing a FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the FS, and approval by the DOEE, by March 16, 2022. After completion and approval of the FS, DOEE will prepare a Proposed Plan for public comment and then issue a ROD identifying any further response actions determined to be necessary. PHI, Pepco, and Generation 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 Pepco and Generation, 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 Pepco and Pepco Energy Services 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. In April 2018, DOEE released a draft RI report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing.

Pepco has determined that it is probable that costs for remediation will be incurred and recorded a liability in the third quarter 2019 for management's best estimate of its share of those costs. On September 30, 2020, DOEE released its Interim ROD. 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. Pepco 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.

On July 12, 2021, DOEE and NPS held a virtual meeting with the PRP's in response to a General Notice Letter sent by each agency inviting the PRP's to participate in discussions, which PEPCO attended.

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 Natural Resources Damages (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 assessment process, Pepco cannot reasonably estimate the range of loss.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims (Exelon and Generation). Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The estimated liabilities are recorded on an undiscounted basis and exclude the estimated legal costs associated with handling these matters, which could be material.

At September 30, 2021 and December 31, 2020, Exelon and Generation had recorded estimated liabilities of approximately $82 million and $89 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2021, approximately $ 19 million of this amount related to 211 open claims presented to Generation, while the remaining $63 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2055, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether adjustments to the estimated liabilities are necessary.

It is reasonably possible that additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued could have a material, unfavorable impact in Exelon’s and Generation’s financial statements. However, management cannot reasonably estimate a range of loss beyond the amounts recorded.

Deferred Prosecution Agreement (DPA) and Related Matters (Exelon and ComEd). Exelon and ComEd received a grand jury subpoena in the second quarter of 2019 from the U.S. Attorney's Office for the Northern District of Illinois (USAO) requiring production of information concerning their lobbying activities in the State of Illinois. On October 4, 2019, Exelon and ComEd received a second grand jury subpoena from the USAO requiring production of records of any communications with certain individuals and entities. 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 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 provides that the USAO will 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 SEC’s investigation remains ongoing and Exelon and ComEd have cooperated fully and intend to continue to cooperate fully with the

SEC. Exelon and ComEd cannot predict the outcome of the SEC investigation. No loss contingency has been reflected in Exelon's and ComEd's consolidated financial statements with respect to the SEC investigation, as this contingency is neither probable nor reasonably estimable at this time.

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, 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 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 December 2, 2020, the court appointed interim lead plaintiffs in the federal cases which consisted of counsel for three of the four federal cases. These plaintiffs filed a consolidated complaint on January 5, 2021. CUB also filed its own complaint against ComEd only on the same day. The remaining federal case, Potter, et al. v. Exelon et al, differed from the other lawsuits as it named additional individual defendants not named in the consolidated complaint. However, the Potter plaintiffs voluntarily dismissed their complaint without prejudice on April 5, 2021. ComEd and Exelon moved to dismiss the consolidated class action complaint and CUB's complaint on February 4, 2021 and briefing was completed on March 22, 2021. On March 25, 2021, the parties agreed, along with state court plaintiffs, discussed below, to jointly engage in mediation. The parties participated in a one-day mediation on June 7, 2021 but no settlement was reached. 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 have appealed the ruling to the Seventh Circuit Court of Appeals. Plaintiffs' opening appeal brief is due January 14, 2022, Exelon's and ComEd's response brief is due February 14, 2022, and Plaintiffs' reply brief is due March 7, 2022. Plaintiffs also refiled their state law claims in state court and have moved to consolidate that action with the already pending consumer state court class action, discussed below. CUB also refiled its state law claims in state court.

- 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 its 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. Oral argument on the state court pending motion to dismiss was held on August 4, 2021. On September 27, 2021, the court set a tentative ruling date on the motion to dismiss for November 30, 2021. It is unclear at this time what impact the recent filings by the federal court plaintiffs and CUB will have on this action and the pending motion to dismiss.

- 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 the motion remains pending. Litigation has proceeded and 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. The parties are currently engaged in discovery; however, on September 9, 2021, the U.S. government moved to intervene in this lawsuit and stay discovery relating to the U.S. government's ongoing criminal proceedings until the parties to the litigation agree to an acceptable protective order. The court granted the U.S. government's motion on September 23, 2021 and discovery remains stayed until further order of the court.

- Five shareholders sent letters to the Exelon Board of Directors between 2020 and 2021 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 parties will confer in advance of the 120-day deadline to determine whether the stay should be extended.
- A separate shareholder demand seeking a review of certain Exelon books and records was received in August 2021. Exelon is in the process of responding to this demand.

No loss contingencies have been reflected in Exelon's and ComEd's consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.

On August 12, 2021, the ICC commenced a proceeding, under its general regulatory authority, to investigate whether the conduct described in the DPA resulted in ComEd's recovery, through rates, of costs that were not properly recoverable under law and, if so, what remedial action should be taken. The Staff Report cited by the ICC in its initiating order expressed "concerns" about whether ComEd improperly recovered DPA-related costs from customers. The Illinois Attorney General and CUB have intervened in the proceeding. Counsel for plaintiffs in the putative consumer class actions pending in Illinois Circuit Court have also sought to "partially" intervene, which request is pending. On October 14, 2021, as required by provisions of the Clean Energy Law, the ICC initiated a separate docket to investigate the rate treatment of costs associated with the DPA, including the fine paid by ComEd, and whether ComEd "collected, spent, allocated, transferred, remitted, or caused in any other way to be expended ratepayer funds that were not lawfully recoverable through rates, and which should accordingly be refunded to ratepayers …." That proceeding must be completed within 330 days. On October 19, 2021, the ICC moved to consolidate these two proceedings because they address "similar issues and facts." That motion is pending. No schedule has been set for submission of testimony or for an evidentiary hearing in either docket. A status hearing is set in both matters for November 4, 2021. Exelon and ComEd cannot predict the outcome of these proceedings.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages (Exelon and Generation). Beginning on February 15, 2021, Generation's Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions. See Note 3 — Regulatory Matters for additional information.

Various lawsuits have been filed against Generation since March 2021 related to these events, including:

- On March 5, 2021, Generation, along with more than 160 power generators and transmission and distribution companies, was sued by approximately 160 individually named plaintiffs, purportedly on behalf of all Texans who allegedly suffered loss of life or sustained personal injury, property damage or other losses as a result of the weather events. The plaintiffs allege that the defendants failed to properly prepare for the cold weather and failed to properly conduct their operations, seeking compensatory as well as punitive damages. On April 26, 2021, another multi-plaintiff lawsuit was filed on behalf of approximately 90 plaintiffs against more than 300 defendants, including Generation, involving similar allegations of liability and claims of personal injury and property damage. Since March 2021, approximately 60 additional lawsuits, naming multiple defendants including Generation, were filed by individual or multiple plaintiffs in different Texas counties, all arising out of the February weather events. These additional lawsuits allege wrongful death, property damage, or other losses. Co-defendants in these lawsuits include ERCOT, transmission and distribution utilities and other generators. Generation disputes liability and denies that it is responsible for any of plaintiffs' alleged claims and is vigorously contesting them. No loss contingencies have been reflected in Exelon's and Generation's consolidated financial statements with respect to these matters, as such contingencies are neither probable nor reasonably estimable at this time.

- On March 22, 2021, an LDC filed a lawsuit in Missouri federal court against Generation for breach of contract and unjust enrichment, seeking damages of approximately $40 million. The plaintiff claims that Generation failed to deliver gas to its customers in February of 2021, causing the plaintiff to incur damages by forcing it to purchase gas for Generation's customers and by Generation's refusal to pay the resulting penalties. On March 26, 2021, Generation filed a complaint with the MPSC against the LDC to void the OFO penalties, or alternatively to grant a waiver or variance from the tariff requirements, to prohibit the LDC from billing or otherwise attempting to collect from Generation or any Missouri customer any portion of the penalties claimed by the LDC until the resolution of the complaint, and to prohibit the LDC from taking any retaliatory measure, including termination of service. On September 1, 2021, the MPSC consolidated Generation's complaint with two other similar complaints from other companies. The evidentiary hearing for the three consolidated complaint cases is scheduled for March 2022. Based on the penalty provisions within the tariff that was in effect at the relevant time, Exelon and Generation have recorded a liability of approximately $40 million as of September 30, 2021.

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 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.

16. Changes in Accumulated Other Comprehensive Income (Exelon)

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

Three Months Ended September 30, 2021	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (5)	$ (3,264)	$ (20)	$ (3,289)
OCI before reclassifications	—	14	(3)	11
Amounts reclassified from AOCI	—	55	—	55
Net current-period OCI	—	69	(3)	66
Ending balance	$ (5)	$ (3,195)	$ (23)	$ (3,223)

Three Months Ended September 30, 2020	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (3)	$ (3,096)	$ (33)	$ (3,132)
OCI before reclassifications	(1)	(13)	3	(11)
Amounts reclassified from AOCI	—	39	—	39
Net current-period OCI	(1)	26	3	28
Ending balance	$ (4)	$ (3,070)	$ (30)	$ (3,104)

Nine Months Ended September 30, 2021	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (5)	$ (3,372)	$ (23)	$ (3,400)
OCI before reclassifications	(1)	15	—	14
Amounts reclassified from AOCI	—	163	—	163
Net current-period OCI	(1)	178	—	177
Ending balance	$ (6)	$ (3,194)	$ (23)	$ (3,223)

Nine Months Ended September 30, 2020	Losses on Cash Flow Hedges	Pension and Non-Pension Postretirement Benefit Plan Items[(a)]	Foreign Currency Items	Total
Beginning balance	$ (2)	$ (3,165)	$ (27)	$ (3,194)
OCI before reclassifications	(2)	(17)	(3)	(22)
Amounts reclassified from AOCI	—	112	—	112
Net current-period OCI	(2)	95	(3)	90
Ending balance	$ (4)	$ (3,070)	$ (30)	$ (3,104)

(a) AOCI amounts are included in the computation of net periodic pension and OPEB cost. See Note 11 — 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):

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 1	$ 4	$ 3	$ 12
Actuarial loss reclassified to periodic benefit cost	(19)	(16)	(57)	(50)
Pension and non-pension postretirement benefit plans valuation adjustment	(7)	3	(8)	6

17. Variable Interest Entities (Exelon, Generation, PHI, and ACE)

At September 30, 2021 and December 31, 2020, Exelon, Generation, PHI, and ACE collectively consolidated several VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see *Consolidated VIEs* below) and had significant interests in several other VIEs for which the applicable Registrant does not have the power to direct the entities' activities and, accordingly, was not the primary beneficiary (see *Unconsolidated VIEs* below). Consolidated and unconsolidated VIEs are aggregated to the extent that the entities have similar risk profiles.

Consolidated VIEs

The table below shows the carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the consolidated financial statements of Exelon, Generation, PHI, and ACE as of September 30, 2021 and December 31, 2020. The assets, except as noted in the footnotes to the table below, can only be used to settle obligations of the VIEs. The liabilities, except as noted in the footnote to the table below, are such that creditors, or beneficiaries, do not have recourse to the general credit of Exelon, Generation, PHI, and ACE.

	September 30, 2021				December 31, 2020			
	Exelon	Generation	PHI(a)	ACE	Exelon	Generation	PHI(a)	ACE
Cash and cash equivalents	$ 38	$ 38	$ —	$ —	$ 98	$ 98	$ —	$ —
Restricted cash and cash equivalents	47	42	5	5	47	44	3	3
Accounts receivable								
Customer	25	25	—	—	148	148	—	—
Other	7	7	—	—	36	36	—	—
Unamortized energy contract assets	21	21	—	—	22	22	—	—
Inventories, net								
Materials and supplies	14	14	—	—	244	244	—	—
Assets held for sale(b)	—	—	—	—	101	101	—	—
Other current assets	517	513	4	—	674	669	5	—
Total current assets	669	660	9	5	1,370	1,362	8	3
Property, plant, and equipment, net	2,052	2,052	—	—	5,803	5,803	—	—
Nuclear decommissioning trust funds	—	—	—	—	3,007	3,007	—	—
Unamortized energy contract assets	210	210	—	—	249	249	—	—
Other noncurrent assets	22	13	9	9	52	42	10	10
Total noncurrent assets	2,284	2,275	9	9	9,111	9,101	10	10
Total assets(c)	$ 2,953	$ 2,935	$ 18	$ 14	$ 10,481	$ 10,463	$ 18	$ 13
Long-term debt due within one year	$ 80	$ 70	$ 10	$ 6	$ 94	$ 68	$ 26	$ 21
Accounts payable	11	11	—	—	81	81	—	—
Accrued expenses	14	14	—	—	70	70	—	—
Unamortized energy contract liabilities	—	—	—	—	4	4	—	—
Liabilities held for sale(b)	—	—	—	—	16	16	—	—
Other current liabilities	—	—	—	—	5	5	—	—
Total current liabilities	105	95	10	6	270	244	26	21
Long-term debt	832	832	—	—	889	889	—	—
Asset retirement obligations	149	149	—	—	2,318	2,318	—	—
Other noncurrent liabilities	3	3	—	—	129	129	—	—
Total noncurrent liabilities	984	984	—	—	3,336	3,336	—	—
Total liabilities(d)	$ 1,089	$ 1,079	$ 10	$ 6	$ 3,606	$ 3,580	$ 26	$ 21

(a) Includes certain purchase accounting adjustments from the PHI merger not pushed down to ACE.

(b) In the fourth quarter of 2020, Generation entered into an agreement for the sale of a significant portion of Generation's solar business, and as a result of this transaction, Exelon and Generation reclassified the consolidated VIEs' solar assets and liabilities as held for sale. Completion of the transaction occurred in the first quarter of 2021. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information on the solar business.

(c) Exelon's and Generation's balances include unrestricted assets for current unamortized energy contract assets of $21 million and $22 million, non-current unamortized energy contract assets of $210 million and $249 million, assets held for sale of $0 million and $9 million, and other unrestricted assets of $0 million and $1 million as of September 30, 2021 and December 31, 2020, respectively.

(d) Exelon's and Generation's balances include liabilities with recourse of $1 million and $8 million as of September 30, 2021 and December 31, 2020, respectively.

As of September 30, 2021 and December 31, 2020, Exelon's and Generation's consolidated VIEs included the following:

Consolidated VIE or VIE groups:	Reason entity is a VIE:	Reason Generation is primary beneficiary:
CENG - A joint venture between Generation and EDF. Generation had a 50.01% equity ownership in CENG as of December 31, 2020 and acquired EDF's 49.99% equity interest on August 6,2021 resulting in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. See additional discussion below.	Disproportionate relationship between equity interest and operational control as a result of the NOSA described further below.	Generation conducts the operational activities.
EGRP - A collection of wind and solar project entities. Generation has a 51% equity ownership in EGRP. See additional discussion below.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Bluestem Wind Energy Holdings, LLC - A Tax Equity structure which is consolidated by EGRP. Generation has a noncontrolling interest.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
Antelope Valley - A solar generating facility, which is 100% owned by Generation. Antelope Valley sells all of its output to PG&E through a PPA.	The PPA contract absorbs variability through a performance guarantee.	Generation conducts all activities.
Equity investment in distributed energy company - Generation has a 31% equity ownership. This distributed energy company has an interest in an unconsolidated VIE. (See Unconsolidated VIEs disclosure below). Generation fully impaired this investment in 2019.	Similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation conducts the operational activities.
NER - A bankruptcy remote, special purpose entity which is 100% owned by Generation, which purchases certain of Generation's customer accounts receivable arising from the sale of retail electricity. NER's assets will be available first and foremost to satisfy the claims of the creditors of NER. See Note 6 - Accounts Receivable for additional information on the sale of receivables.	Equity capitalization is insufficient to support its operations.	Generation conducts all activities.

CENG - On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the NOSA pursuant to which Generation conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF.

On November 20, 2019, Generation received notice of EDF's intention to exercise the put option to sell its 49.99% equity interest in CENG to Generation and the put automatically exercised on January 19, 2020. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation purchased EDF's equity interest in CENG and resulted in CENG no longer being classified as a consolidated VIE beginning in the third quarter of 2021. Refer to Note 2 — Mergers, Acquisitions, and Dispositions for additional information.

Exelon and Generation, where indicated, provide the following support to CENG:

- Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. See Note 19 — Commitments and Contingencies of the Exelon 2020 Form 10-K for more details.
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

Prior to August 6, 2021, Generation and EDF shared in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance. Following the execution of the settlement agreement, EDF no longer shares in the obligation.

EGRP - EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While Generation or EGRP owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. There is limited recourse to Generation related to certain solar and wind entities.

In 2017, Generation's interests in EGRP were contributed to and are pledged for the ExGen Renewables IV non-recourse debt project financing structure. Refer to Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on ExGen Renewables IV.

As of September 30, 2021 and December 31, 2020, Exelon's, PHI's, and ACE's consolidated VIE consists of:

Consolidated VIEs:	Reason entity is a VIE:	Reason ACE is the primary beneficiary:
ACE Funding - A special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE's recoverable stranded costs through the issuance and sale of Transition Bonds. Proceeds from the sale of each series of Transition Bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees.	ACE's equity investment is a variable interest as, by design, it absorbs any initial variability of ATF. The bondholders also have a variable interest for the investment made to purchase the Transition Bonds.	ACE controls the servicing activities.

Unconsolidated VIEs

Exelon's and Generation's variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected in Exelon's and Generation's Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements.

As of September 30, 2021 and December 31, 2020, Exelon and Generation had significant unconsolidated variable interests in several VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements.

The following table presents summary information about Exelon's and Generation’s significant unconsolidated VIE entities:

	September 30, 2021			December 31, 2020		
	Commercial Agreement VIEs	Equity Investment VIEs	Total	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 781	$ 370	$ 1,151	$ 777	$ 401	$ 1,178
Total liabilities[(a)]	80	209	289	61	223	284
Exelon's ownership interest in VIE[(a)]	—	143	143	—	157	157
Other ownership interests in VIE[(a)]	701	18	719	716	21	737

(a) These items represent amounts in the unconsolidated VIE balance sheets, not in Exelon’s or Generation’s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs. Exelon and Generation do not have any exposure to loss as they do not have a carrying amount in the equity investment VIEs as of September 30, 2021 and December 31, 2020.

As of September 30, 2021 and December 31, 2020, Exelon's and Generation's unconsolidated VIEs consist of:

Unconsolidated VIE groups:	Reason entity is a VIE:	Reason Generation is not the primary beneficiary:
Equity investments in distributed energy companies - 1) Generation has a 90% equity ownership in a distributed energy company. 2) Generation, via a consolidated VIE, has a 90% equity ownership in another distributed energy company (See Consolidated VIEs disclosure above). Generation fully impaired this investment in 2019.	Similar structures to a limited partnership and the limited partners do not have kick out rights with respect to the general partner.	Generation does not conduct the operational activities.
Energy Purchase and Sale agreements - Generation has several energy purchase and sale agreements with generating facilities.	PPA contracts that absorb variability through fixed pricing.	Generation does not conduct the operational activities.

18. 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.

	Operating revenues			
	Exelon	Generation	PHI	DPL
Three Months Ended September 30, 2021				
Operating lease income	$ 30	$ 29	$ 1	$ 1
Variable lease income	71	71	—	—
Three Months Ended September 30, 2020				
Operating lease income	$ 30	$ 28	$ 1	$ 1
Variable lease income	76	76	—	—
Nine Months Ended September 30, 2021				
Operating lease income	$ 47	$ 44	$ 3	$ 3
Variable lease income	208	207	1	1
Nine Months Ended September 30, 2020				
Operating lease income	$ 48	$ 43	$ 3	$ 3
Variable lease income	225	224	1	1

	Taxes other than income taxes								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended September 30, 2021									
Utility taxes[(a)]	$ 242	$ 27	$ 67	$ 41	$ 21	$ 86	$ 80	$ 6	$ —
Property	165	66	13	5	46	34	23	10	1
Payroll	57	26	7	4	5	7	2	1	1
Three Months Ended September 30, 2020									
Utility taxes[(a)]	$ 237	$ 26	$ 66	$ 41	$ 21	$ 83	$ 77	$ 5	$ 1
Property	152	66	7	4	42	32	21	10	1
Payroll	59	29	7	4	4	6	2	1	1
Nine Months Ended September 30, 2021									
Utility taxes[(a)]	$ 665	$ 73	$ 188	$ 107	$ 66	$ 231	$ 212	$ 17	$ 2
Property	470	199	30	13	131	97	65	30	2
Payroll	180	83	20	12	14	21	5	4	2
Nine Months Ended September 30, 2020									
Utility taxes[(a)]	$ 651	$ 75	$ 181	$ 102	$ 65	$ 228	$ 210	$ 16	$ 2
Property	449	199	23	12	121	94	63	29	2
Payroll	183	88	21	12	13	21	6	4	3

(a) Generation's utility tax represents gross receipts tax related to its retail operations, and the Utility 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	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Three Months Ended September 30, 2021									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory Agreement Units	$ 263	$ 263	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	102	102	—	—	—	—	—	—	—
Net unrealized losses on NDT funds									
Regulatory Agreement Units	(195)	(195)	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	(88)	(88)	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[b]	(38)	(38)	—	—	—	—	—	—	—
Decommissioning-related activities	44	44	—	—	—	—	—	—	—
AFUDC — Equity	36	—	10	7	7	12	9	2	1
Non-service net periodic benefit cost	19	—	—	—	—	—	—	—	—
Net unrealized losses from equity investments[c]	(179)	(179)	—	—	—	—	—	—	—
Three Months Ended September 30, 2020									
Decommissioning-related activities:									
Net realized income on NDT funds[a]									
Regulatory Agreement Units	$ 50	$ 50	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	23	23	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	398	398	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	254	254	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities[b]	(359)	(359)	—	—	—	—	—	—	—
Decommissioning-related activities	366	366	—	—	—	—	—	—	—
AFUDC — Equity	27	—	7	5	6	9	7	1	1
Non-service net periodic benefit cost	15	—	—	—	—	—	—	—	—

	Other, net								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Nine Months Ended September 30, 2021									
Decommissioning-related activities:									
Net realized income on NDT funds(a)									
Regulatory Agreement Units	$ 698	$ 698	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	392	392	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	84	84	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	38	38	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities(b)	(607)	(607)	—	—	—	—	—	—	—
Decommissioning-related activities	605	605	—	—	—	—	—	—	—
AFUDC — Equity	99	—	23	19	21	36	30	4	2
Non-service net periodic benefit cost	64	—	—	—	—	—	—	—	—
Net unrealized losses from equity investments(c)	(83)	(83)	—	—	—	—	—	—	—
Nine Months Ended September 30, 2020									
Decommissioning-related activities:									
Net realized income on NDT funds(a)									
Regulatory Agreement Units	$ 127	$ 127	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Non-Regulatory Agreement Units	127	127	—	—	—	—	—	—	—
Net unrealized gains on NDT funds									
Regulatory Agreement Units	111	111	—	—	—	—	—	—	—
Non-Regulatory Agreement Units	1	1	—	—	—	—	—	—	—
Regulatory offset to NDT fund-related activities(b)	(192)	(192)	—	—	—	—	—	—	—
Decommissioning-related activities	174	174	—	—	—	—	—	—	—
AFUDC — Equity	76	—	22	12	16	26	20	3	3
Non-service net periodic benefit cost	38	—	—	—	—	—	—	—	—

(a) Realized income includes interest, dividends and realized gains and losses on sales of NDT fund investments.
(b) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of income taxes related to all NDT fund activity for those units. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information regarding the accounting for nuclear decommissioning and Note 8 — Nuclear Decommissioning for additional information on the contractual offset suspension for the Byron units.
(c) Net unrealized losses from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Supplemental Cash Flow Information

The following tables provide additional information about material items recorded in the Registrants' Consolidated Statements of Cash Flows.

	Depreciation, amortization, and accretion								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Nine Months Ended September 30, 2021									
Property, plant, and equipment(a)	$ 4,505	$ 2,698	$ 721	$ 249	$ 324	$ 467	$ 204	$ 126	$ 115
Amortization of regulatory assets(a)	439	—	172	10	110	147	98	31	18
Amortization of intangible assets, net(a)	44	37	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	23	23	—	—	—	—	—	—	—
Nuclear fuel(c)	810	810	—	—	—	—	—	—	—
ARO accretion(d)	383	383	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 6,204	$ 3,951	$ 893	$ 259	$ 434	$ 614	$ 302	$ 157	$ 133
Nine Months Ended September 30, 2020									
Property, plant, and equipment(a)	$ 2,831	$ 1,121	$ 689	$ 238	$ 293	$ 436	$ 191	$ 116	$ 104
Amortization of regulatory assets(a)	434	—	152	21	112	149	91	27	30
Amortization of intangible assets, net(a)	47	40	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities(b)	24	22	—	—	—	—	—	—	—
Nuclear fuel(c)	708	708	—	—	—	—	—	—	—
ARO accretion(d)	375	375	—	—	—	—	—	—	—
Total depreciation, amortization, and accretion	$ 4,419	$ 2,266	$ 841	$ 259	$ 405	$ 585	$ 282	$ 143	$ 134

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

	Other non-cash operating activities								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Nine Months Ended September 30, 2021									
Pension and non-pension postretirement benefit costs	$ 304	$ 92	$ 97	$ 5	$ 45	$ 36	$ 5	$ 2	$ 8
Allowance for credit losses	155	59	34	36	7	18	9	3	6
Other decommissioning-related activity[a]	(810)	(810)	—	—	—	—	—	—	—
Energy-related options[b]	45	45	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates[c]	(129)	—	(32)	(20)	17	(94)	(54)	(17)	(23)
Severance costs	(67)	(75)	1	—	—	1	—	—	—
Long-term incentive plan	94	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	146	98	2	—	22	21	5	7	3
AFUDC — Equity	(99)	—	(23)	(19)	(21)	(36)	(30)	(4)	(2)
Nine Months Ended September 30, 2020									
Pension and non-pension postretirement benefit costs	$ 310	$ 89	$ 85	$ 4	$ 46	$ 52	$ 11	$ 6	$ 10
Allowance for credit losses	130	16	23	38	12	41	24	15	2
Other decommissioning-related activity[a]	(301)	(301)	—	—	—	—	—	—	—
Energy-related options[b]	79	79	—	—	—	—	—	—	—
True-up adjustments to decoupling mechanisms and formula rates[c]	66	—	51	(10)	10	15	(20)	15	20
Severance costs	96	88	1	—	—	—	—	—	—
Provision for excess and obsolete inventory	119	118	1	1	—	(1)	—	(1)	—
Long-term incentive plan	(8)	—	—	—	—	—	—	—	—
Amortization of operating ROU asset	185	135	1	—	23	21	5	6	2
Deferred Prosecution Agreement payments[d]	200	—	200	—	—	—	—	—	—
AFUDC — Equity	(76)	—	(22)	(12)	(16)	(26)	(20)	(3)	(3)

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units except for decommissioning-related impacts that were not offset for the Byron units starting in the second quarter of 2021, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income, and income taxes related to all NDT fund activity for these units. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information regarding the accounting for nuclear decommissioning and Note 8 — Nuclear Decommissioning for additional information on the contractual offset suspension for the Byron units.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(c) 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 BGE, Pepco, DPL, and ACE, reflects the change in regulatory assets and liabilities associated with their decoupling mechanisms and transmission formula rates. For PECO, reflects the change in regulatory assets and liabilities associated with its transmission formula rates. See Note 3 — Regulatory Matters for additional information.

(d) See Note 15 — Commitments and Contingencies for additional information related to the Deferred Prosecution Agreement.

The following tables provide a reconciliation of cash, cash equivalents, and restricted cash reported within the Registrants' Consolidated Balance Sheets that sum to the total of the same amounts in their Consolidated Statements of Cash Flows.

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2021									
Cash and cash equivalents	$ 2,957	$ 1,957	$ 241	$ 344	$ 225	$ 82	$ 19	$ 13	$ 16
Restricted cash and cash equivalents	473	62	276	8	27	71	41	26	5
Restricted cash included in other long-term assets	54	—	44	—	—	9	—	—	9
Total cash, restricted cash, and cash equivalents	$ 3,484	$ 2,019	$ 561	$ 352	$ 252	$ 162	$ 60	$ 39	$ 30
December 31, 2020									
Cash and cash equivalents	$ 663	$ 226	$ 83	$ 19	$ 144	$ 111	$ 30	$ 15	$ 17
Restricted cash and cash equivalents	438	89	279	7	1	39	35	—	3
Restricted cash included in other long-term assets	53	—	43	—	—	10	—	—	10
Cash, restricted cash, and cash equivalents - Held for Sale	12	12	—	—	—	—	—	—	—
Total cash, restricted cash, and cash equivalents	$ 1,166	$ 327	$ 405	$ 26	$ 145	$ 160	$ 65	$ 15	$ 30
September 30, 2020									
Cash and cash equivalents	$ 1,858	$ 623	$ 76	$ 242	$ 326	$ 196	$ 125	$ 26	$ 13
Restricted cash and cash equivalents	485	100	305	7	1	38	33	—	4
Restricted cash included in other long-term assets	137	—	127	—	—	10	—	—	10
Total cash, restricted cash, and cash equivalents	$ 2,480	$ 723	$ 508	$ 249	$ 327	$ 244	$ 158	$ 26	$ 27
December 31, 2019									
Cash and cash equivalents	$ 587	$ 303	$ 90	$ 21	$ 24	$ 131	$ 30	$ 13	$ 12
Restricted cash and cash equivalents	358	146	150	6	1	36	33	—	2
Restricted cash included in other long-term assets	177	—	163	—	—	14	—	—	14
Total cash, restricted cash, and cash equivalents	$ 1,122	$ 449	$ 403	$ 27	$ 25	$ 181	$ 63	$ 13	$ 28

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2020 Form 10-K.

Supplemental Balance Sheet Information

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

	Accrued expenses								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2021									
Compensation-related accruals(a)	$ 894	$ 318	$ 148	$ 66	$ 72	$ 108	$ 34	$ 21	$ 16
Taxes accrued	508	222	80	61	90	98	67	16	7
Interest accrued	415	77	65	36	39	75	37	20	15
December 31, 2020									
Compensation-related accruals(a)	$ 1,069	$ 426	$ 170	$ 73	$ 84	$ 109	$ 36	$ 18	$ 17
Taxes accrued	527	229	94	16	73	117	90	18	12
Interest accrued	331	44	109	37	46	51	26	7	12

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

19. Related Party Transactions (All Registrants)

Operating revenues from affiliates

Generation

The following table presents Generation’s Operating revenues from affiliates, which are primarily recorded as Purchased power from affiliates and an immaterial amount recorded as Operating and maintenance expense from affiliates at the Utility Registrants:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Operating revenues from affiliates:				
ComEd(a)(b)	$ 96	$ 71	$ 249	$ 241
PECO(c)	59	68	142	146
BGE(d)	65	84	195	252
PHI	99	105	276	288
Pepco(e)	69	80	199	219
DPL(f)	25	21	63	60
ACE(g)	5	4	14	9
Other	5	3	10	5
Total operating revenues from affiliates (Generation)	$ 324	$ 331	$ 872	$ 932

(a) Generation has an ICC-approved RFP contract with ComEd to provide a portion of ComEd’s electricity supply requirements. Generation also sells RECs and ZECs to ComEd.

(b) For the three and nine months ended September 30, 2021, respectively, ComEd’s Purchased power from Generation of $94 million and $256 million is recorded as Operating revenues from ComEd of $96 million and $249 million and as Purchased power and fuel from ComEd of $2 million and $(7) million at Generation. For the three and nine months ended September 30, 2020, respectively, ComEd’s Purchased power from Generation of $71 million and $252 million is recorded as Operating revenues from ComEd of $71 million and $241 million and as Purchased power and fuel from ComEd of less than $1 million and $11 million at Generation.

(c) Generation provides electric supply to PECO under contracts executed through PECO's competitive procurement process. In addition, Generation has a ten-year agreement with PECO to sell solar AECs.

(d) Generation provides a portion of BGE's energy requirements under its MDPSC-approved market-based SOS and gas commodity programs.

(e) Generation provides electric supply to Pepco under contracts executed through Pepco's competitive procurement process approved by the MDPSC and DCPSC.

(f) Generation provides a portion of DPL's energy requirements under its MDPSC and DPSC-approved market-based SOS commodity programs.

(g) Generation provides electric supply to ACE under contracts executed through ACE's competitive procurement process.

PHI

PHI's Operating revenues from affiliates are primarily with BSC for services that PHISCO provides to BSC.

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			
	Three Months Ended September 30,		Nine Months Ended September 30,		Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020	2021	2020	2021	2020
Exelon								
BSC					$ 149	$ 148	$ 431	$ 390
PHISCO					18	15	54	45
Generation								
BSC	$ 145	$ 133	$ 424	$ 406	43	13	76	37
ComEd								
BSC	71	65	214	204	47	49	148	133
PECO								
BSC	41	34	120	107	12	20	57	53
BGE								
BSC	45	38	133	120	20	30	62	88
PHI								
BSC	40	36	116	107	27	36	88	79
PHISCO	—	—	—	—	18	15	54	45
Pepco								
BSC	23	20	68	61	11	14	36	29
PHISCO	26	28	84	90	7	7	22	20
DPL								
BSC	14	13	43	38	10	12	29	26
PHISCO	24	24	73	73	6	4	17	13
ACE								
BSC	14	11	37	32	7	10	22	22
PHISCO	21	21	64	65	5	4	15	12

Current Receivables from/Payables to affiliates

The following tables present current receivables from affiliates and current payables to affiliates:

September 30, 2021

	Receivables from affiliates:										
Payables to affiliates:	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
Generation		$ 36	$ 9	$ —	$ —	$ —	$ —	$ 86	$ —	$ 23	$ 154
ComEd	$ 103 (a)		—	—	—	—	—	49	—	6	158
PECO	24	3		1	—	—	—	25	—	7	60
BGE	15	—	—		—	—	—	32	—	2	49
PHI	—	—	—	—	—	—	—	2	—	10	12
Pepco	22	—	—	—		1	—	15	13	—	51
DPL	4	—	—	—	—		—	9	11	—	24
ACE	7	—	—	—	—	—		9	9	1	26
Other	9	2	—	1	—	—	1	2	—		15
Total	$ 184	$ 41	$ 9	$ 2	$ —	$ 1	$ 1	$ 229	$ 33	$ 49	$ 549

December 31, 2020

	Receivables from affiliates:										
Payables to affiliates:	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**BSC**	**PHISCO**	**Other**	**Total**
Generation		$ 13	$ —	$ —	$ —	$ —	$ —	$ 72	$ —	$ 22	$ 107
ComEd	$ 78 (a)		—	—	—	—	—	59	—	9	146
PECO	17	1		—	—	—	—	28	—	4	50
BGE	11	—	—		—	—	—	47	—	3	61
PHI	—	—	—	—	—	—	—	4	—	11	15
Pepco	13	2	—	1		—	—	25	14	—	55
DPL	3	1	—	—	—		—	21	10	1	36
ACE	6	—	—	—	—	—		15	9	1	31
Other	25	5	2	2	2	1	6	—	—		43
Total	$ 153	$ 22	$ 2	$ 3	$ 2	$ 1	$ 6	$ 271	$ 33	$ 51	$ 544

(a) As of September 30, 2021 and December 31, 2020, Generation had a contract liability with ComEd for $27 million and $50 million, respectively, that was included in Other current liabilities on Generation's Consolidated Balance Sheets. As of September 30, 2021 and December 31, 2020, ComEd had a Current Payable to Generation of $76 million and $28 million, respectively, on its Consolidated Balance Sheets, which consisted of Generation's Current Receivable from ComEd, partially offset by Generation's contract liability with ComEd.

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. Generation, ComEd, PECO, and PHI Corporate participate in the Exelon money pool. Pepco, DPL, and ACE participate in the PHI intercompany money pool.

Noncurrent Receivables from/Payables to affiliates

Generation has long-term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 10 — Asset Retirement Obligations of the Exelon 2020 Form 10-K for additional information.

The following table presents noncurrent receivables from affiliates at ComEd and PECO which are recorded as noncurrent payables to affiliates at Generation:

	September 30, 2021	December 31, 2020
ComEd	$ 2,597	$ 2,541
PECO	546	475

Long-term debt to financing trusts

The following table presents Long-term debt to financing trusts:

	September 30, 2021			December 31, 2020		
	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

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) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term debt to affiliates in Generation's Consolidated Balance Sheets and intercompany notes receivable at Exelon Corporate.

20. Planned 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. Under the separation plan, Exelon shareholders will retain their current shares of Exelon stock and receive a pro-rata distribution of shares of the new company's stock in a transaction that is expected to be tax-free to Exelon and its shareholders for U.S. federal income tax purposes. The actual number of shares to be distributed to Exelon shareholders will be determined prior to closing.

Exelon is targeting to complete the separation in the first quarter of 2022, subject to final approval by Exelon's Board of Directors, a Form 10 registration statement being declared effective by the SEC, regulatory approvals, and satisfaction of other conditions. The transaction is subject to approval by FERC, NRC, and NYPSC and receipt of a private letter ruling from the IRS and tax opinion from Exelon's tax advisors.

On February 25, 2021, Exelon and Generation filed applications with FERC, NYPSC, and NRC seeking approvals for the separation of Generation. On March 25, 2021, Exelon filed a request for a private letter ruling with the IRS to confirm the tax-free treatment of the planned separation, which was received on September 23, 2021. On August 24, 2021, Exelon and Generation received approval from FERC for the planned separation. Exelon and Generation expect a decision from the NRC in the fourth quarter of 2021 and have requested a decision from the NYPSC before the end of 2021. Exelon and Generation cannot predict if the remaining applications will be approved as filed.

There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing.

ITEM 2. 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 generation, delivery, and marketing of energy through Generation and the energy distribution and transmission businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE.

Exelon has eleven reportable segments consisting of Generation's five reportable segments (Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions), 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 eight separate operating subsidiary registrants, Generation, 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, Generation, 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.

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net Income attributable to common shareholders by Registrant for the three and nine months ended September 30, 2021 compared to the same period in 2020. For additional information regarding the financial results for the three and nine months ended September 30, 2021 and 2020 see the discussions of Results of Operations by Registrant.

	Three Months Ended September 30,		Favorable (unfavorable) variance	Nine Months Ended September 30,		Favorable (unfavorable) variance
	2021	2020		2021	2020	
Exelon	$ 1,203	$ 501	$ 702	$ 1,315	$ 1,604	$ (289)
Generation	607	49	558	(247)	570	(817)
ComEd	220	196	24	609	304	305
PECO	111	138	(27)	383	317	66
BGE	36	53	(17)	290	273	17
PHI	266	216	50	535	418	117
Pepco	130	118	12	264	227	37
DPL	50	27	23	135	91	44
ACE	90	75	15	141	106	35
Other(a)	(37)	(151)	114	(255)	(278)	23

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

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income attributable to common shareholders** increased by $702 million and diluted earnings per average common share increased to $1.23 in 2021 from $0.51 in 2020 primarily due to:

- Absence of an impairment in the New England asset group;
- Absence of one time charges recorded in the third quarter of 2020 associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the reversal of one-time charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;
- Higher mark-to-market gains;
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices;
- Higher electric distribution earnings from higher rate base and higher allowed ROE due to an increase in treasury rates at ComEd; and
- The favorable impacts of the multi-year plan at BGE and regulatory rate increases at DPL and Pepco.

The increases were partially offset by:

- Lower net unrealized and realized gains on NDT funds;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date;
- Accelerated depreciation and amortization associated with Generation's previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and Generation's decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024; and
- Higher net unrealized and realized losses on equity investments.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income attributable to common shareholders** decreased by $289 million and diluted earnings per average common share decreased to $1.34 in 2021 from $1.64 in 2020 primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with Generation's previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and Generation's decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date;
- Impairments at Generation of the New England asset group, the Albany Green Energy biomass facility, and a wind project, partially offset by the absence of an impairment of the New England asset group in the third quarter of 2020; and
- The absence of a prior year one-time tax settlement.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized and realized gains on NDT funds;

- Absence of one time charges recorded in the third quarter of 2020 associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and Mystic generating station assets, and the reversal of one-time charges;
- Lower nuclear outage days;
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices;
- Lower operating and maintenance expense at ComEd due to the payments that ComEd made in 2020 under the Deferred Prosecution Agreement;
- Higher electric distribution earnings from higher rate base and higher allowed ROE due to an increase in treasury rates at ComEd;
- The favorable impacts of the multi-year plan at BGE and regulatory rate increases at Pepco, DPL, and ACE;
- Favorable weather conditions at PECO and DPL's Delaware service territory;
- Favorable volume at PECO; and
- Lower storm costs at PECO and DPL due to the absence of the June 2020 and August 2020 storms, respectively.

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-to-year operating results and provide an indication of Exelon’s baseline operating performance excluding items that are considered by management to be not 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 tables provide a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three and nine months ended September 30, 2021 compared to the same period in 2020.

(In millions, except per share data)	Three Months Ended September 30, 2021	2021 Earnings per Diluted Share	2020	2020 Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 1,203	$ 1.23	$ 501	$ 0.51
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $192 and $62, respectively)	(559)	(0.57)	(183)	(0.19)
Unrealized (Gains) Losses Related to NDT Fund Investments (net of taxes of $70 and $161, respectively)(a)	55	0.06	(172)	(0.18)
Asset Impairments (net of taxes of $11 and $126, respectively)(b)	33	0.03	375	0.38
Plant Retirements and Divestitures (net of taxes of $71 and $111, respectively)(c)	211	0.22	329	0.34
Cost Management Program (net of taxes of $1 and $5, respectively)(d)	6	0.01	15	0.02
Change in Environmental Liabilities (net of taxes of $1 and $6, respectively)	4	—	17	0.02
COVID-19 Direct Costs (net of taxes of $1 and $3, respectively)(e)	7	0.01	10	0.01
ERP System Implementation Costs (net of taxes $1)(h)	4	—	—	—
Planned Separation Costs (net of taxes of $10)(i)	27	0.03	—	—
Costs Related to Suspension of Contractual Offset (net of taxes of $33)(j)	107	0.11	—	—
Asset Retirement Obligation (net of taxes of $12 and $1, respectively)(k)	(35)	(0.04)	3	—
Acquisition Related Costs (net of taxes of $2 and $1, respectively)(g)	7	0.01	2	—
Income Tax-Related Adjustments (entire amount represents tax expense)(l)	19	0.02	62	0.06
Noncontrolling Interests (net of taxes of $5 and $12, respectively)(m)	(17)	(0.02)	57	0.06
Adjusted (non-GAAP) Operating Earnings	$ 1,070	$ 1.09	$ 1,017	$ 1.04

	Nine Months Ended September 30,			
	2021		2020	
(In millions, except per share data)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 1,315	$ 1.34	$ 1,604	$ 1.64
Mark-to-Market Impact of Economic Hedging Activities (net of taxes of $317 and $112, respectively)	(924)	(0.94)	(329)	(0.34)
Unrealized (Gains) Losses Related to NDT Fund Investments (net of taxes of $24 and $31, respectively)(a)	(32)	(0.03)	8	0.01
Asset Impairments (net of taxes of $135 and $134, respectively)(b)	401	0.41	396	0.40
Plant Retirements and Divestitures (net of taxes of $290 and $117, respectively)(c)	865	0.88	348	0.36
Cost Management Program (net of taxes of $2 and $11, respectively)(d)	10	0.01	34	0.03
Change in Environmental Liabilities (net of taxes of $2 and $6, respectively)	6	0.01	18	0.02
COVID-19 Direct Costs (net of taxes of $9 and $13, respectively)(e)	24	0.02	37	0.04
Deferred Prosecution Agreement Payments (net of taxes of $0)(f)	—	—	200	0.20
ERP System Implementation Costs (net of taxes of $2)(h)	10	0.01	—	—
Planned Separation Costs (net of taxes of $16)(i)	46	0.05	—	—
Costs Related to Suspension of Contractual Offset (net of taxes of $45)(j)	148	0.15	—	—
Asset Retirement Obligation (net of taxes of $12 and $1, respectively)(k)	(35)	(0.04)	3	—
Acquisition Related Costs (net of taxes of $5 and $1, respectively)(g)	15	0.02	2	—
Income Tax-Related Adjustments (entire amount represents tax expense)(l)	15	0.02	66	0.07
Noncontrolling Interests (net of taxes of $2 and $2, respectively)(m)	16	0.02	17	0.02
Adjusted (non-GAAP) Operating Earnings	$ 1,879	$ 1.92	$ 2,403	$ 2.46

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. For all items except the unrealized gains and losses related to NDT fund investments, the marginal statutory income tax rates for 2021 and 2020 ranged from 25.0% to 29.0%. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 56.2% and 48.3% for the three months ended September 30, 2021 and 2020, respectively. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 42.4% and 134.1% for the nine months ended September 30, 2021 and 2020, respectively.

(a) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory Agreement Units.
(b) In 2021, reflects an impairment in the New England asset group, an impairment recorded as a result of the agreement to sell the Albany Green Energy biomass facility, and an impairment of a wind project at Generation. In 2020, reflects an impairment at ComEd related to the acquisition of transmission assets and an impairment in the New England asset group in the third quarter of 2020.
(c) In 2021, primarily reflects accelerated depreciation and amortization associated with Generation's decisions to early retire Byron, Dresden, and Mystic Units 8 and 9, partially offset by reversal of one-time charges resulting from the reversal of the previous decision to retire Byron and Dresden on September 15, 2021 and a gain on sale of Generation's solar business.

Depreciation for Byron and Dresden was adjusted beginning September 15, 2021 to reflect the extended useful life estimates. In 2020, primarily reflects one-time charges and accelerated depreciation and amortization expenses associated with Generation's decisions in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021 and Mystic Units 8 and 9 in 2024.

(d) Primarily represents reorganization and severance costs related to cost management programs.

(e) Represents direct costs related to COVID-19 consisting primarily of costs to acquire personal protective equipment, costs for cleaning supplies and services, and costs to hire healthcare professionals to monitor the health of employees.

(f) Reflects the payments made by ComEd under the Deferred Prosecution Agreement, which ComEd entered in July 2020 with the U.S. Attorney's Office for the Northern District of Illinois.

(g) Reflects costs related to the acquisition of EDF's interest in CENG, which was completed in the third quarter of 2021.

(h) Reflects costs related to a multi-year Enterprise Resource Program (ERP) system implementation.

(i) Represents costs related to the planned separation primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the planned separation, and employee-related severance costs.

(j) Decommissioning-related activities for the former ComEd and PECO units (Regulatory Agreement Units), net of applicable taxes, including realized and unrealized gains and losses on the NDT funds, depreciation of the ARC, and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's consolidated statements of operations. These costs reflect the impact of suspension of contractual offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date.

(k) For Generation, reflects an adjustment to the nuclear asset obligation for the Non-Regulatory Agreement Units resulting from the annual update in the third quarter of 2021.

(l) Primarily reflects the adjustment to deferred income taxes due to changes in forecasted apportionment.

(m) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to unrealized gains and losses on NDT fund investments for CENG units prior to Generation's acquisition of EDF's interest in CENG on August 6, 2021 and the noncontrolling interest portion of a wind project impairment.

Significant 2021 Transactions and Developments

Planned 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 with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separation gives each company the financial and strategic independence to focus on its specific customer needs, while executing its core business strategy.

On February 25, 2021, Exelon and Generation filed applications with FERC, NYPSC, and NRC seeking approvals for the separation of Generation. On March 25, 2021, Exelon filed a request for a private letter ruling with the IRS to confirm the tax-free treatment of the planned separation, which was received on September 23, 2021. On August 24, 2021, Exelon and Generation received approval from FERC for the planned separation. Exelon and Generation expect a decision from the NRC in the fourth quarter of 2021 and have requested a decision from the NYPSC before the end of 2021. Exelon and Generation cannot predict if the remaining applications will be approved as filed.

In connection with the planned separation, Exelon incurred transaction costs of approximately $36 million and $64 million on a pre-tax basis for the three and nine months ended September 30, 2021, respectively, which are excluded from Adjusted (non-GAAP) Operating Earnings. The transaction costs are primarily comprised of system-related costs, third-party costs paid to advisors, consultants, lawyers, and other experts assisting in the planned separation, and employee-related severance costs.

There can be no assurance that any separation transaction will ultimately occur or, if one does occur, of its terms or timing. See Note 20 — Planned Separation of the Combined Notes to Consolidated Financial Statements for additional information.

CENG Put Option

EDF had the option to sell its 49.99% equity interest in CENG to Generation exercisable beginning on January 1, 2016 and thereafter until June 30, 2022. On November 20, 2019, Generation received notice of EDF's intention to exercise the put option and sell its 49.99% equity interest in CENG to Generation and the put automatically exercised on January 19, 2020 at the end of the sixty-day advance notice period. On August 6, 2021, Generation and EDF entered into a settlement agreement pursuant to which Generation, through a wholly owned subsidiary, purchased EDF's equity interest in CENG for a net purchase price of $885 million, which includes, among other things, an adjustment for EDF's share of the balance of the preferred distribution payable by CENG to

Generation. The difference between the net purchase price and EDF's noncontrolling interest as of the closing date was recorded to Common Stock in Exelon's Consolidated Balance Sheet and Membership Interest in Generation's Consolidated Balance Sheet.

In connection with the settlement agreement, on August 6, 2021, Generation issued approximately $880 million under a term loan credit agreement to fund the transaction, which will expire on August 5, 2022.

See Note 2 – Mergers, Acquisitions, and Dispositions and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Clean Energy Law

On September 15, 2021, the Illinois Public Act 102-0662 was signed into law by the Governor of Illinois ("Clean Energy Law"). The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the state's transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Among other things, the Clean Energy Law authorizes the IPA to procure up to 54.5 million CMCs from qualifying nuclear plants for a five-year period beginning on June 1, 2022 through May 31, 2027. CMCs are credits for the carbon-free attributes of eligible nuclear power plants in PJM. The Byron, Dresden, and Braidwood nuclear plants located in Illinois will be eligible to participate in the CMC procurement process and, if awarded contracts, would be committed to operate through May 31, 2027. Selected generators will by December 3, 2021 contract directly with ComEd for the procurement of the CMCs based upon the number of MWhs produced annually by the eligible facilities, subject to specified caps and minimum performance requirements. ComEd is required to purchase CMCs from eligible nuclear facilities and all its costs of doing so will be recovered through a new rider.

Following enactment of the Clean Energy Law, Generation announced on September 15, 2021, that it has reversed its previous decision to retire Byron and Dresden given the opportunity for additional revenue. In addition, Generation no longer considers the Braidwood or LaSalle nuclear plants to be at risk for premature retirement. See Note 7 – Early Plant Retirements for additional information and Early Retirement of Generation Facilities below.

The Clean Energy Law also contains requirements associated with ComEd's transition away from the performance-based electric distribution formula rate. The law authorizing that rate setting process sunsets at the end of 2022. The Clean Energy Law, and tariffs adopted under it, governs both the remaining reconciliations of rates set under that process and requires ComEd to file in 2023 its choice of either a general rate case or a four-year multi-year plan to set rates that take effect in 2024. If ComEd elects to file a multi-year plan, that plan would set rates for 2024 – 2027, based on forecasted revenue requirements and an ICC determined rate of return on rate base, including the cost of common equity. See Note 3 – Regulatory Matters for additional information and other features of the Clean Energy Law.

Early Retirement of Generation Facilities

In August 2020, Generation announced that it intended to retire the Byron Generating Station in September 2021, Dresden Generating Station in November 2021, and Mystic Units 8 and 9 at the expiration of the cost of service commitment in May 2024. As a result, Exelon and Generation recognized certain one-time charges in the third and fourth quarters of 2020. Further, there were ongoing annual financial impacts stemming from shortening the expected economic useful lives of these facilities, primarily related to accelerated depreciation of plant assets (including any ARC) and accelerated amortization of nuclear fuel.

Also, as a result, in the third quarter of 2020, Exelon and Generation recognized a $500 million pre-tax impairment for the New England asset group. In the second quarter of 2021, an incremental decline in value resulted in an additional pre-tax impairment charge of $350 million for the New England asset group.

Further, in the second quarter and third quarter of 2021, Exelon and Generation recorded a pre-tax charge of $53 million and $140 million, respectively for decommissioning-related activities that were not offset for the Byron units due to the inability to recognize a regulatory asset at ComEd.

All of the charges above were excluded from Exelon's and Generation's Adjusted (non-GAAP) Operating Earnings.

On September 15, 2021, Generation reversed its previous decision to early retire Byron and Dresden and updated the expected economic useful life for both facilities to 2044 and 2046 for Byron Units 1 and 2, respectively, and to 2029 and 2031 for Dresden Units 2 and 3, respectively. Depreciation was therefore adjusted beginning September 15, 2021, to reflect these extended useful life estimates. In addition, in the third quarter of 2021, Exelon and Generation reversed approximately $81 million of severance benefit costs and $13 million of other one-time charges initially recorded in the third and fourth quarters of 2020 associated with the early retirements, which were excluded from Exelon's and Generation’s Adjusted (non-GAAP) Operating Earnings.

The following table summarizes the incremental expense for Byron, Dresden, and Mystic Units 8 and 9 and the reversal of one-time charges for Byron and Dresden recorded in the three and nine months ended September 30, 2021. For Mystic Units 8 and 9, the projected amounts for the remainder of 2021 and through the retirement date of 2024 are not expected to be material.

Income statement expense (pre-tax)	**Three Months Ended September 30, 2021**	**Nine Months Ended September 30, 2021**
Depreciation and amortization		
Accelerated depreciation[(a)]	$ 574	$ 1,845
Accelerated nuclear fuel amortization	42	148
Operating and maintenance		
Reversal of one-time charges	(94)	(94)
Other charges	4	8
Contractual offset[(b)]	(60)	(451)
Total	$ 466	$ 1,456

(a) Reflects incremental accelerated depreciation of plant assets, including any ARC.

(b) Reflects contractual offset for ARO accretion, ARC depreciation, and net impacts associated with the remeasurement of the ARO for Byron and Dresden and exclude any changes in earnings in the NDT funds. Decommissioning-related activities were not offset for the Byron units starting in the second quarter of 2021 due to the inability to recognize a regulatory asset at ComEd. With Generation’s September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date. Based on the regulatory agreement with the ICC, decommissioning-related activities are offset in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income as long as the net cumulative decommissioning-related activities result in a regulatory liability at ComEd. Recognition of a regulatory asset for nuclear decommissioning-related activities at ComEd is not permissible. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd.

See Note 7 — Early Plant Retirements, Note 8 — Nuclear Decommissioning, and Note 9 - Asset Impairments of the Combined Notes to Consolidated Financial Statements for additional information.

Impacts of the February 2021 Extreme Cold Weather Event and Texas-based Generating Assets Outages

Beginning on February 15, 2021, Generation’s Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced outages as a result of extreme cold weather conditions. In addition, those weather conditions drove increased demand for service, dramatically increased wholesale power prices, and also increased gas prices in certain regions.

The estimated impact to Exelon’s and Generation’s Net income for the nine months ended September 30, 2021 arising from these market and weather conditions was a reduction of approximately $880 million. The estimated impact to Exelon's and Generation's Net income for the three months ended September 30, 2021 was not material. The nine months ended estimated impact includes certain charges associated with the natural gas business that may be reduced through waivers and/or recoveries from customers. Therefore, such charges are not included in the estimated full year earnings impact. Exelon and Generation estimate a reduction in Net income of approximately $670 million to $820 million for the full year 2021. The ultimate impact to Exelon’s and Generation’s consolidated financial statements may be affected by a number of factors, the impacts of customer and counterparty credit losses, any state or federal solutions to address the financial challenges caused by the event, and related litigation and contract disputes. See Note 3 — Regulatory Matters and Note 15 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon expects to offset between $410 million and $490 million of this impact for the full year 2021 primarily at Generation through a combination of enhanced revenue opportunities, deferral of selected non-essential maintenance, and primarily one-time cost savings.

Agreement for the Sale of a Generation Biomass Facility

On April 28, 2021, Generation and ReGenerate entered into a purchase agreement, under which ReGenerate agreed to purchase Generation's interest in the Albany Green Energy biomass facility. As a result, in the second quarter of 2021, Exelon and Generation recorded a pre-tax impairment charge of $140 million which is excluded from Exelon's and Generation's Adjusted (non-GAAP) Operating Earnings. The sale was completed on June 30, 2021 for a net purchase price of $36 million. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Utility Rates and Base Rate 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 2021. 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 (Decrease) Increase	Approved Revenue Requirement (Decrease) Increase	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois	April 16, 2020	Electric	$ (11)	$ (14)	8.38 %	December 9, 2020	January 1, 2021
PECO - Pennsylvania	September 30, 2020	Natural Gas	69	29	10.24 %	June 22, 2021	July 1, 2021
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 %		
Pepco - District of Columbia	May 30, 2019 (amended June 1, 2020)	Electric	136	109	9.275 %	June 8, 2021	July 1, 2021
Pepco - Maryland	October 26, 2020 (amended March 31, 2021)	Electric	104	52	9.55 %	June 28, 2021	June 28, 2021
DPL - Delaware	March 6, 2020 (amended February 2, 2021)	Electric	23	14	9.60 %	September 15, 2021	October 6, 2020
ACE - New Jersey	December 9, 2020 (amended February 26, 2021)	Electric	67	41	9.60 %	July 14, 2021	January 1, 2022

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Service	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ComEd - Illinois	April 16, 2021	Electric	$ 51	7.36 %	Fourth quarter of 2021
PECO - Pennsylvania	March 30, 2021	Electric	246	10.95 %	Fourth quarter of 2021
DPL - Maryland	September 1, 2021	Electric	29	10.10 %	First quarter of 2022

Transmission Formula Rates

The following total increases/(decreases) were included in the Utility Registrants' 2021 electric transmission formula rate updates. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Registrant	Initial Revenue Requirement Increase (Decrease)	Annual Reconciliation Increase	Total Revenue Requirement Increase	Allowed Return on Rate Base	Allowed ROE
ComEd	$ 33	$ 12	$ 45	8.20 %	11.50 %
PECO	(2)	26	24	7.37 %	10.35 %
BGE	38	27	65	7.35 %	10.50 %
Pepco	(9)	21	12	7.68 %	10.50 %
DPL	19	33	52	7.20 %	10.50 %
ACE	27	24	51	7.45 %	10.50 %

Other Key Business Drivers and Management Strategies

The following discussion of other key business driver and management strategies includes current developments of previously disclosed matters and new issues arising during the period that may impact future financial statements. This section should be read in conjunction with ITEM 1. Business and ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Other Key Business Drivers and Management Strategies in the Registrants' combined 2020 Form 10-K and Note 15 — Commitments and Contingencies to the Consolidated Financial Statements in this report for additional information on various environmental matters.

Power Markets

Complaint at FERC Seeking to Alter Capacity Market Default Offer Caps

On February 21, 2019, PJM's Independent Market Monitor (IMM) filed a complaint alleging that the number of performance assessment intervals used to calculate the default offer cap for bids to supply capacity in PJM is too high, resulting in an overstated default offer cap that obviates the need for most sellers to seek unit-specific approval of their offers. The IMM argued that this allows for the exercise of market power. The IMM asked FERC to require PJM to reduce the number of performance assessment intervals used to calculate the opportunity costs of a capacity supplier assuming a capacity obligation. This would, in turn, lower the default offer cap and allow the IMM to review more offers on a unit-specific basis. Several consumer advocates filed a complaint seeking similar relief several months after the IMM's complaint. On March 18, 2021, FERC granted the complaints, finding the current estimate of performance assessment intervals to be excessive compared to the reasonably expected number of performance assessment intervals which results in an unjust and unreasonable default offer cap. FERC did not establish the number of performance assessment intervals that should be used to calculate the default offer cap and instead requested briefs on the matter, including alternative approaches to mitigation in the capacity market. Exelon submitted an initial and reply briefs on May 3, 2021 and June 9, 2021, respectively, and an answer to briefs filed by other parties on June 24, 2021. On September 2, 2021, FERC issued an order adopting the IMM's unit-specific avoidable cost offer review methodology and directed PJM to submit a compliance filing establishing new deadlines for offer review and related other activities leading up to the base residual auction for the 2023-2024 planning year and an additional compliance filing revising the PJM Tariff to comply with FERC's order. Exelon filed at FERC for rehearing on this matter on October 4, 2021. Generation cannot predict the outcome of these proceedings or the financial statement impact.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96%-99% for the remainder of 2021. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk.

Generation procures natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Approximately 60% of Generation's uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's consolidated financial statements.

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

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Environmental Regulation

Exelon is well positioned to support increasingly ambitious government climate policy and to partner with our customers and communities to reduce GHG emissions.

In August 2021, the Utility Registrants announced a "path to clean" goal to collectively reduce their operations-driven emissions 50% by 2030 against a 2015 baseline, and to reach net zero operations-driven emissions by 2050. This goal builds upon Exelon's long-standing commitment to reducing our GHG emissions. The Utility Registrants "path to clean" will include efficiency and clean electricity for operations, vehicle fleet electrification, equipment and processes to reduce sulfur hexafluoride (SF6) leakage, modern natural gas infrastructure to minimize methane leaks and increase safety and reliability, and investment and collaboration to develop new technologies.

Generation produces electricity predominantly from low- and zero-carbon generating facilities (such as nuclear, hydroelectric, natural gas, wind, and solar PV) and neither owns nor operates any coal-fueled generating assets. Generation's natural gas fired generating plants produce GHG emissions, most notably CO2. However, Generation's owned-asset emission intensity, or rate of carbon dioxide equivalent (CO2e) emitted per unit of electricity generated, is among the lowest in the industry.

The United States has set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels by 2030.

Other Legislative and Regulatory Developments

FERC Supplemental Notice of Proposed Rulemaking

On April 15, 2021, FERC issued a Supplemental Notice of Proposed Rulemaking (NOPR) proposing to modify the current regulation permitting a continuous 50-basis-point ROE incentive adder for a transmission utility that joins and remains a member of a RTO. Under the NOPR, the ROE incentive adder would only be available for a period of up to three years after a transmission utility newly joins a RTO and all existing ROE incentive adders would end for transmission utilities that have been members for three or more years. The Utility Registrants' existing transmission rates include the ROE incentive adder. Exelon submitted comments to FERC on this matter on June 25, 2021. Exelon cannot predict the outcome, but a final rule as proposed could have an adverse impact to Exelon's and the Utility Registrants' financial statements. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding the Utility Registrants' transmission formula rates and regulatory proceedings at FERC.

City of Chicago Franchise Agreement

ComEd has had a Franchise Agreement with the City of Chicago (the City) since 1992. The Franchise Agreement grants rights to use the public right of way to install, maintain, and operate the wires, poles, and other infrastructure required to deliver electricity to residents and businesses across the City. 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 been reached. Accordingly, the 1992 Franchise Agreement remains in effect at this time. In April 2021, the City invited interested parties to respond to a Request for Information (RFI) regarding the franchise for electricity delivery. Under this process, the City could choose to terminate the ComEd Franchise Agreement on one year notice and grant a franchise to another party instead. Final responses to the RFI were due on July 30, 2021, however, on July 29, 2021, the City chose to extend the final submission deadline to September 30, 2021. ComEd submitted its response to the RFI by the due date and looks forward to continuing engagement with the City about its response. While Exelon and ComEd cannot predict the ultimate outcome of the RFI and the

Franchise Agreement, 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.

Employees

In the second quarter of 2021, Generation and PECO ratified CBAs as follows:

- Generation ratified its CBA with UGSOA, which covers 73 security officers at Three Mile Island. The CBA will expire in 2023.
- PECO ratified two CBAs with IBEW Local 614 which covers 1,140 operations employees and 185 customer service employees, respectively. Both CBAs expire in 2026.

In the third quarter of 2021, Generation ratified its CBA with the National Union of Nuclear Security Officers, which covers 88 security officers at Braidwood. The CBA will expire in 2024.

Critical Accounting Policies and Estimates

Management of each of the Registrants makes a number of significant estimates, assumptions, and judgments in the preparation of its financial statements. At September 30, 2021, the Registrants’ critical accounting policies and estimates had not changed significantly from December 31, 2020. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Critical Accounting Policies and Estimates in the Registrants' 2020 Form 10-K for further information.

Results of Operations by Registrant

Results of Operations — Generation

	Three Months Ended September 30,		(Unfavorable) Favorable Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2021	2020		2021	2020	
Operating revenues	$ 4,406	$ 4,659	$ (253)	$ 14,117	$ 13,272	$ 845
Operating expenses						
Purchased power and fuel	1,546	2,314	768	8,103	6,961	(1,142)
Operating and maintenance	938	1,737	799	3,413	4,188	775
Depreciation and amortization	866	558	(308)	2,735	1,161	(1,574)
Taxes other than income taxes	115	118	3	354	364	10
Total operating expenses	3,465	4,727	1,262	14,605	12,674	(1,931)
Gain on sales of assets and businesses	65	—	65	144	12	132
Operating income (loss)	1,006	(68)	1,074	(344)	610	(954)
Other income and (deductions)						
Interest expense, net	(77)	(80)	3	(225)	(277)	52
Other, net	(115)	367	(482)	561	199	362
Total other income and (deductions)	(192)	287	(479)	336	(78)	414
Income (loss) before income taxes	814	219	595	(8)	532	(540)
Income taxes	177	100	(77)	108	41	(67)
Equity in losses of unconsolidated affiliates	(4)	(2)	(2)	(6)	(6)	—
Net income (loss)	633	117	516	(122)	485	(607)
Net income (loss) attributable to noncontrolling interests	26	68	(42)	125	(85)	210
Net income (loss) attributable to membership interest	$ 607	$ 49	$ 558	$ (247)	$ 570	$ (817)

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income attributable to membership interest** increased by $558 million primarily due to:

- Absence of an impairment in the New England asset group;
- Absence of one time charges recorded in the third quarter of 2020 associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the

reversal of one-time charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;

- Higher mark-to-market gains; and
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices.

The increases were partially offset by:

- Lower net unrealized and realized gains on NDT funds;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date;
- Accelerated depreciation and amortization associated with Generation's previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and Generation's decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024; and
- Higher net unrealized and realized losses on equity investments.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income attributable to membership interest** decreased by $817 million primarily due to:

- Impacts of the February 2021 extreme cold weather event;
- Accelerated depreciation and amortization associated with Generation's previous decision in the third quarter of 2020 to early retire Byron and Dresden nuclear facilities in 2021, a decision which was reversed on September 15, 2021, and Generation's decision in the third quarter of 2020 to early retire Mystic Units 8 and 9 in 2024;
- Decommissioning-related activities that were not offset for the Byron units beginning in the second quarter of 2021 through September 15, 2021. With Generation's September 15, 2021 reversal of the previous decision to retire Byron, Generation resumed contractual offset for Byron as of that date;
- Impairments of the New England asset group, the Albany Green Energy biomass facility at Generation, and a wind project at Generation, partially offset by the absence of an impairment of the New England asset group in the third quarter of 2020; and
- The absence of a prior year one-time tax settlement.

The decreases were partially offset by:

- Higher mark-to-market gains;
- Higher net unrealized and realized gains on NDT funds;
- Absence of one time charges recorded in the third quarter of 2020 associated with Generation's decision to early retire the Byron and Dresden nuclear facilities and Mystic Units 8 and 9, and the reversal of one-time charges resulting from the reversal of the previous decision to early retire Byron and Dresden on September 15, 2021;
- Lower nuclear outage days; and
- Higher New York ZEC revenues due to higher generation and an increase in ZEC prices.

Operating revenues. The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Generation's five reportable segments are Mid-Atlantic, Midwest, New York, ERCOT, and Other Power Regions. See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall operating revenues or results of operations.

For the three and nine months ended September 30, 2021 compared to 2020, Operating revenues by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021	**2020**	**Variance**	**% Change(a)**	**2021**	**2020**	**Variance**	**% Change(a)**
Mid-Atlantic(b)	$ 1,272	$ 1,313	$ (41)	(3.1) %	$ 3,527	$ 3,561	$ (34)	(1.0) %
Midwest(c)	985	1,043	(58)	(5.6) %	2,945	3,007	(62)	(2.1) %
New York	455	406	49	12.1 %	1,173	1,061	112	10.6 %
ERCOT	358	330	28	8.5 %	890	754	136	18.0 %
Other Power Regions	1,260	1,109	151	13.6 %	3,729	2,984	745	25.0 %
Total electric revenues	4,330	4,201	129	3.1 %	12,264	11,367	897	7.9 %
Other	711	421	290	68.9 %	2,811	1,667	1,144	68.6 %
Mark-to-market (losses) gains	(635)	37	(672)		(958)	238	(1,196)	
Total Operating revenues	$ 4,406	$ 4,659	$ (253)	(5.4) %	$ 14,117	$ 13,272	$ 845	6.4 %

(a) % Change in mark-to-market is not a meaningful measure.
(b) Includes results of transactions with PECO, BGE, Pepco, DPL, and ACE.
(c) Includes results of transactions with ComEd.

Supply Sources. Generation’s supply sources by region are summarized below:

	Three Months Ended September 30,				Nine Months Ended September 30,			
Supply Source (GWhs)	**2021**	**2020**	**Variance**	**% Change**	**2021**	**2020**	**Variance**	**% Change**
Nuclear Generation[a]								
Mid-Atlantic	13,753	13,679	74	0.5 %	40,203	39,630	573	1.4 %
Midwest	23,909	24,471	(562)	(2.3)%	70,363	71,929	(1,566)	(2.2)%
New York	7,188	6,734	454	6.7 %	21,323	19,296	2,027	10.5 %
Total Nuclear Generation	44,850	44,884	(34)	(0.1)%	131,889	130,855	1,034	0.8 %
Fossil and Renewables								
Mid-Atlantic	491	304	187	61.5 %	1,675	1,864	(189)	(10.1)%
Midwest	177	196	(19)	(9.7)%	763	852	(89)	(10.4)%
New York	—	1	(1)	(100.0)%	1	3	(2)	(66.7)%
ERCOT	4,670	4,394	276	6.3 %	10,250	10,658	(408)	(3.8)%
Other Power Regions	2,409	2,794	(385)	(13.8)%	7,641	8,905	(1,264)	(14.2)%
Total Fossil and Renewables	7,747	7,689	58	0.8 %	20,330	22,282	(1,952)	(8.8)%
Purchased Power								
Mid-Atlantic	4,565	8,252	(3,687)	(44.7)%	12,123	17,924	(5,801)	(32.4)%
Midwest	77	71	6	8.5 %	386	595	(209)	(35.1)%
ERCOT	595	1,104	(509)	(46.1)%	2,626	3,351	(725)	(21.6)%
Other Power Regions	13,585	14,512	(927)	(6.4)%	38,778	37,981	797	2.1 %
Total Purchased Power	18,822	23,939	(5,117)	(21.4)%	53,913	59,851	(5,938)	(9.9)%
Total Supply/Sales by Region								
Mid-Atlantic[b]	18,809	22,235	(3,426)	(15.4)%	54,001	59,418	(5,417)	(9.1)%
Midwest[b]	24,163	24,738	(575)	(2.3)%	71,512	73,376	(1,864)	(2.5)%
New York	7,188	6,735	453	6.7 %	21,324	19,299	2,025	10.5 %
ERCOT	5,265	5,498	(233)	(4.2)%	12,876	14,009	(1,133)	(8.1)%
Other Power Regions	15,994	17,306	(1,312)	(7.6)%	46,419	46,886	(467)	(1.0)%
Total Supply/Sales by Region	71,419	76,512	(5,093)	(6.7)%	206,132	212,988	(6,856)	(3.2)%

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants. Includes the total output for fully owned plants and the total output for CENG prior to the acquisition of EDF's interest on August 6, 2021 as CENG was fully consolidated. See Note 2 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on Generation’s acquisition of EDF's interest in CENG.

(b) Includes affiliate sales to PECO, BGE, Pepco, DPL, and ACE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for the Generation-operated plants, which reflects ownership percentage of stations operated by Exelon, excluding Salem, which is operated by PSEG. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under

GAAP and may not be comparable to other companies’ presentations or be more useful than the GAAP information provided elsewhere in this report.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Nuclear fleet capacity factor	96.0 %	96.0 %	95.0 %	95.1 %
Refueling outage days	22	17	172	203
Non-refueling outage days	—	4	10	15

ZEC Prices. Generation is compensated through state programs for the carbon-free attributes of its nuclear generation. ZEC prices have a significant impact on Operating revenues. The following table presents the average ZEC prices ($/MWh) for each of Generation's major regions in which state programs have been enacted. Prices reflect the weighted average price for the various delivery periods within each calendar year.

	Three Months Ended September 30,				Nine Months Ended September 30,			
State (Region)	2021	2020	Variance	% Change	2021	2020	Variance	% Change
New Jersey (Mid-Atlantic)	$ 10.00	$ 10.00	$ —	— %	$ 10.00	$ 10.00	$ —	— %
Illinois (Midwest)	16.50	16.50	—	— %	16.50	16.50	—	— %
New York (New York)	21.38	19.59	1.79	9.1 %	20.78	19.59	1.19	6.1 %

Capacity Prices. Generation participates in capacity auctions in each of its major regions, except ERCOT which does not have a capacity market. Generation also incurs capacity costs associated with load served, except in ERCOT. Capacity prices have a significant impact on Generation's operating revenues and purchased power and fuel. The following table presents the average capacity prices ($/MW Day) for each of Generation's major regions. Prices reflect the weighted average price for the various auction periods within each calendar year.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Location (Region)	2021	2020	Variance	% Change	2021	2020	Variance	% Change
Eastern Mid-Atlantic Area Council (Mid-Atlantic and Midwest)	$ 165.73	$ 187.87	$ (22.14)	(11.8)%	$ 178.03	$ 159.50	$ 18.53	11.6 %
ComEd (Midwest)	195.55	188.12	7.43	3.9 %	191.42	194.22	(2.80)	(1.4)%
Rest of State (New York)	160.44	89.30	71.14	79.7 %	94.12	54.32	39.80	73.3 %
Southeast New England (Other)	154.37	176.67	(22.30)	(12.6)%	166.76	200.69	(33.93)	(16.9)%

Electricity Prices. The price of electricity has a significant impact on Generation's operating revenues and purchased power cost. The following table presents the average day-ahead around-the-clock price ($/MWh) for each of Generation's major regions.

	Three Months Ended September 30,				Nine Months Ended September 30,			
Location (Region)	**2021**	**2020**	**Variance**	**% Change**	**2021**	**2020**	**Variance**	**% Change**
PJM West (Mid-Atlantic)	$ 41.77	$ 22.75	$ 19.02	83.6 %	$ 33.70	$ 20.24	$ 13.46	66.5 %
ComEd (Midwest)	39.68	20.98	18.70	89.1 %	31.76	18.57	13.19	71.0 %
Central (New York)	36.27	19.53	16.74	85.7 %	26.58	16.33	10.25	62.8 %
North (ERCOT)	42.67	27.14	15.53	57.2 %	182.23	21.83	160.40	734.8 %
Southeast Massachusetts (Other)(a)	45.23	22.95	22.28	97.1 %	41.54	21.26	20.28	95.4 %

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

For the three and nine months ended September 30, 2021 compared to 2020, changes in **Operating revenues** by region were approximately as follows:

	Variance	% Change[(a)]	Three Months Ended September 30, 2021	Variance	% Change[(a)]	Nine Months Ended September 30, 2021
Mid-Atlantic	$ (41)	(3.1) %	• unfavorable wholesale load revenue of $(185) primarily due to lower volumes; partially offset by • favorable settled economic hedges of $120 due to settled prices relative to hedged prices • favorable retail load revenue of $20 primarily due to higher prices	$ (34)	(1.0) %	• unfavorable wholesale load revenue of $(370) primarily due to lower volumes; partially offset by • favorable settled economic hedges of $305 due to settled prices relative to hedged prices • favorable retail load revenue of $35 primarily due to higher prices
Midwest	(58)	(5.6) %	• unfavorable settled economic hedges of $(185) due to settled prices relative to hedged prices; partially offset by • favorable net wholesale load and generation revenue of $120 due to higher load volumes and higher prices, partially offset by decreased generation due to higher nuclear outage days	(62)	(2.1) %	• unfavorable settled economic hedges of $(375) due to settled prices relative to hedged prices; partially offset by • favorable net wholesale load and generation revenue of $315 primarily due to higher prices, partially offset by decreased generation due to higher nuclear outage days
New York	49	12.1 %	• favorable nuclear generation revenue of $20 primarily due to lower outage days and higher prices • favorable ZEC revenue of $25 due to higher prices and higher nuclear generation	112	10.6 %	• favorable nuclear generation revenue of $40 primarily due to lower outage days and higher prices • favorable ZEC revenue of $65 due to higher prices and higher nuclear generation
ERCOT	28	8.5 %	• favorable settled economic hedges of $65 due to settled prices relative to hedged prices; partially offset by • unfavorable wholesale load revenue of $(15) primarily due to lower volumes	136	18.0 %	• favorable retail load revenue of $120 primarily due to higher prices in part due to the February 2021 extreme cold weather event
Other Power Regions	151	13.6 %	• favorable retail load revenue of $175 due to higher prices and higher volumes • favorable settled economic hedges of $110 due to settled prices relative to hedged prices; partially offset by • unfavorable wholesale load revenue of $(155) primarily due to lower volumes	745	25.0 %	• favorable settled economic hedges of $520 due to settled prices relative to hedged prices • favorable retail load revenue of $400 due to higher prices and higher volumes; partially offset by • unfavorable wholesale load revenue of $(205) primarily due to lower volumes
Other	290	68.9 %	• favorable gas revenue of $250 primarily due to higher prices	1,144	68.6 %	• favorable gas revenue of $1,060 primarily due to higher prices in part due to the February 2021 extreme cold weather event
Mark-to-market[(b)]	(672)		• losses on economic hedging activities of $(635) in 2021 compared to gains of $37 in 2020	(1,196)		• losses on economic hedging activities of $(958) in 2021 compared to gains of $238 in 2020
Total	$ (253)	(5.4) %		$ 845	6.4 %	

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

Purchased power and fuel. See Operating revenues above for discussion of Generation's reportable segments and hedging strategies and for supplemental statistical data, including supply sources by region, nuclear fleet capacity factor, capacity prices, and electricity prices.

The following business activities are not allocated to a region and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to overall purchased power and fuel expense or results of operations, and accelerated nuclear fuel amortization associated with nuclear decommissioning.

For the three and nine months ended September 30, 2021 compared to 2020, Purchased power and fuel by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021	2020	Variance	% Change[a]	2021	2020	Variance	% Change[a]
Mid-Atlantic[b]	$ 702	$ 722	$ 20	2.8 %	$ 1,815	$ 1,878	$ 63	3.4 %
Midwest[c]	330	293	(37)	(12.6) %	930	829	(101)	(12.2)%
New York	109	121	12	9.9 %	293	336	43	12.8 %
ERCOT	179	183	4	2.2 %	1,812	429	(1,383)	(322.4)%
Other Power Regions	1,049	884	(165)	(18.7) %	3,165	2,446	(719)	(29.4)%
Total electric purchased power and fuel	2,369	2,203	(166)	(7.5) %	8,015	5,918	(2,097)	(35.4)%
Other	566	329	(237)	(72.0) %	2,288	1,277	(1,011)	(79.2)%
Mark-to-market gains	(1,389)	(218)	1,171		(2,200)	(234)	1,966	
Total purchased power and fuel	$ 1,546	$ 2,314	$ 768	33.2 %	$ 8,103	$ 6,961	$ (1,142)	(16.4)%

(a) % Change in mark-to-market is not a meaningful measure.
(b) Includes results of transactions with PECO, BGE, Pepco, DPL, and ACE.
(c) Includes results of transactions with ComEd.

For the three and nine months ended September 30, 2021 compared to 2020, changes in **Purchased power and fuel** by region were approximately as follows:

	Variance	% Change[a]	Three Months Ended September 30, 2021	Variance	% Change[a]	Nine Months Ended September 30, 2021
Mid-Atlantic	$ 20	2.8 %	• no significant changes	$ 63	3.4 %	• favorable purchased power and net capacity impact of $45 primarily due to lower load and higher capacity prices earned partially offset by lower cleared capacity volumes • favorable settlement of economic hedges of $40 due to settled prices relative to hedged prices
Midwest	(37)	(12.6) %	• unfavorable purchased power of $(35) primarily due to lower nuclear generation due to higher nuclear outage days, higher energy prices, and higher load	(101)	(12.2) %	• unfavorable purchased power and net capacity impact of $(140) primarily due to lower nuclear generation due to higher nuclear outage days, higher energy prices, lower cleared capacity volumes, and lower capacity prices
New York	12	9.9 %	• no significant changes	43	12.8 %	• favorable settlement of economic hedges of $70 due to settled prices relative to hedged prices; partially offset by • unfavorable purchased power and net capacity impact of $(35) primarily due to higher energy prices partially offset by higher capacity prices earned
ERCOT	4	2.2 %	• favorable purchased power of $85 primarily due to a favorable recovery related to the February 2021 extreme cold weather event and lower load; partially offset by • unfavorable settlement of economic hedges of $(75) due to settled prices relative to hedged prices	(1,383)	(322.4) %	• unfavorable purchased power of $(750) primarily due to higher energy prices primarily during the February 2021 extreme cold weather event • unfavorable settlement of economic hedges of $(460) due to settled prices relative to hedged prices • unfavorable fuel cost of $(150) primarily due to higher gas prices
Other Power Regions	(165)	(18.7) %	• unfavorable purchased power and net capacity impact of $(190) primarily due to lower generation, higher energy prices, and lower cleared capacity volumes; partially offset by • favorable settlement of economic hedges of $45 due to settled prices relative to hedged prices	(719)	(29.4) %	• unfavorable purchased power and net capacity impact of $(680) primarily due to higher load, lower generation, higher energy prices, lower cleared capacity volumes, and lower capacity prices • unfavorable RPS expense of $(55) primarily due to higher prices and higher load • unfavorable fuel cost of $(40) primarily due to higher gas prices; partially offset by • favorable settlement of economic hedges of $80 due to settled prices relative to hedged prices
Other	(237)	(72.0) %	• unfavorable net gas purchase costs and settlement of economic hedges of $(190) • unfavorable accelerated nuclear fuel amortization associated with announced early plant retirements of $(20)	(1,011)	(79.2) %	• unfavorable net gas purchase costs and settlement of economic hedges of $(830) • unfavorable accelerated nuclear fuel amortization associated with announced early plant retirements of $(125)
Mark-to-market[b]	1,171		• gains on economic hedging activities of $1,389 in 2021 compared to gains of $218 in 2020	1,966		• gains on economic hedging activities of $2,200 in 2021 compared to gains of $234 in 2020
Total	$ 768	33.2 %		$ (1,142)	(16.4) %	

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

(b) See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on mark-to-market gains and losses.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	(Decrease) Increase	Increase (Decrease)
Asset impairments	$ (456)	$ 23
Plant retirements and divestitures[a]	(314)	(706)
ARO update	(49)	(49)
Labor, other benefits, contracting, and materials	(25)	(29)
Change in environmental liabilities	(18)	(18)
Cost management program	(12)	(24)
Corporate allocations	(8)	(19)
Credit loss expense	3	46
Acquisition related costs	6	17
Separation costs	16	25
Nuclear refueling outage costs, including the co-owned Salem plants	17	(70)
Other	41	29
Total decrease	$ (799)	$ (775)

(a) Primarily reflects contractual offset of accelerated depreciation and amortization associated with Generation's previous decision to early retire the Byron and Dresden nuclear facilities. See Note 8 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

Depreciation and amortization expense increased for the three and nine months ended September 30, 2021 compared to the same period in 2020, primarily due to the accelerated depreciation and amortization associated with Generation's previous decision to early retire the Byron and Dresden nuclear facilities. This decision was reversed on September 15, 2021 and depreciation for Byron and Dresden was adjusted beginning September 15, 2021 to reflect the extended useful life estimates. A portion of this accelerated depreciation and amortization is offset in Operating and maintenance expense.

Gain on sales of assets and businesses increased for the three and nine months ended September 30, 2021 compared to the same period in 2020, primarily due to gains on sales of equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021, and additionally increased for the nine months ended September 30, 2021 compared to the same period in 2020, due to a gain on sale of Generation's solar business.

Interest expense, net decreased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to mark-to-market gains related to the EGR IV interest swaps entered into in December 2020 and decreases in interest rates. See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on the interest swaps.

Other, net decreased for the three months ended September 30, 2021 compared to the same period in 2020 and increased for the nine months ended September 30, 2021 compared to the same period in 2020, due to activity described in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Net unrealized (losses) gains on NDT funds(a)	$ (94)	$ 254	$ 33	$ 1
Net realized gains on sale of NDT funds(a)	101	—	349	58
Interest and dividend income on NDT funds(a)	26	23	73	69
Contractual elimination of income tax expense(b)	11	89	150	46
Net unrealized losses from equity investments(c)	(179)	—	(83)	—
Other	20	1	39	25
Total other, net	$ (115)	$ 367	$ 561	$ 199

(a) Unrealized (losses) gains, realized gains, and interest and dividend income on the NDT funds are associated with the Non-Regulatory Agreement Units.
(b) Contractual elimination of income tax expense is associated with the income taxes on the NDT funds of the Regulatory Agreement units.
(c) Net unrealized losses from equity investments that became publicly traded entities in the fourth quarter of 2020 and the first half of 2021.

Effective income tax rates were 21.7% and 45.7% for the three months ended September 30, 2021 and 2020, respectively, and (1,350.0)% and 7.7% for the nine months ended September 30, 2021 and 2020, respectively. See Note 10 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Net income attributable to noncontrolling interests decreased for the three months ended September 30, 2021 compared to the same period in 2020, primarily due to lower net gains on NDT fund investments for CENG prior to Generation's acquisition of EDF's interest in CENG on August 6, 2021, and the noncontrolling portion of a wind project impairment, and increased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to higher net gains on NDT fund investments for CENG prior to Generation's acquisition of EDF's interest in CENG on August 6, 2021, partially offset by the noncontrolling portion of a wind project impairment.

Results of Operations — ComEd

	Three Months Ended September 30, 2021	Three Months Ended September 30, 2020	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	Favorable (Unfavorable) Variance
Operating revenues	$ 1,789	$ 1,643	$ 146	$ 4,840	$ 4,499	$ 341
Operating expenses						
Purchased power	703	606	(97)	1,728	1,557	(171)
Operating and maintenance	330	321	(9)	969	1,173	204
Depreciation and amortization	304	294	(10)	893	841	(52)
Taxes other than income taxes	91	81	(10)	243	227	(16)
Total operating expenses	1,428	1,302	(126)	3,833	3,798	(35)
Operating income	361	341	20	1,007	701	306
Other income and (deductions)						
Interest expense, net	(98)	(95)	(3)	(292)	(287)	(5)
Other, net	13	10	3	35	32	3
Total other income and (deductions)	(85)	(85)	—	(257)	(255)	(2)
Income before income taxes	276	256	20	750	446	304
Income taxes	56	60	4	141	142	1
Net income	$ 220	$ 196	$ 24	$ 609	$ 304	$ 305

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income** increased by $24 million as compared to the same period in 2020, primarily due to increased electric distribution formula rate earnings (reflecting the impacts of higher rate base and higher allowed electric distribution ROE due to an increase in treasury rates).

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income** increased by $305 million as compared to the same period in 2020, primarily due to increases in electric distribution formula rate earnings (reflecting the impacts of higher rate base and higher allowed electric distribution ROE due to an increase in treasury rates) and payments that ComEd made in 2020 under the Deferred Prosecution Agreement. See Note 15 - Commitments and Contingencies of the Combined Notes to the Consolidated Financial Statements for additional information related to the Deferred Prosecution Agreement.

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

	Three Months Ended September 30, 2021 Increase	Nine Months Ended September 30, 2021 Increase
Distribution	$ 25	$ 98
Transmission	10	14
Energy efficiency	10	34
Other	8	20
	53	166
Regulatory required programs	93	175
Total increase	$ 146	$ 341

Revenue Decoupling. The demand for electricity is affected by weather conditions and customer usage. Operating revenues are not impacted by abnormal weather, usage per customer or number of customers as a result of the revenue decoupling mechanisms as allowed by 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 for the three and nine months ended September 30, 2021 as compared to the same period in 2020, due to higher allowed ROE due to an increase in treasury rates and the impact of a higher rate base.

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 revenue increased for the three and nine months ended September 30, 2021 as compared to the same periods in 2020 primarily due to the impact of a higher rate base.

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 remained relatively consistent for the three months ended September 30, 2021 as compared to the same period in 2020. Energy efficiency revenue increased during the nine months ended September 30, 2021 as compared to the same period in 2020, primarily due to increased regulatory asset amortization, which is fully recoverable.

Other Revenue primarily includes assistance provided to other utilities through mutual assistance programs. Other revenue increased for the three and nine months ended September 30, 2021 as compared to the same period in 2020, 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, and costs related to electricity, ZEC and REC procurement. 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 ComEd 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, 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 ComEd's revenue disaggregation.

The increase of $97 million and of $171 million for the three and nine months ended September 30, 2021 compared to the same period in 2020, respectively, in **Purchased power expense** is offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	(Decrease) Increase
Deferred Prosecution Agreement payments[(a)]	$ —	$ (200)
Storm-related costs	4	(10)
Pension and non-pension postretirement benefits expense	1	3
Labor, other benefits, contracting and materials	(4)	6
BSC costs	6	11
Other[(b)]	(3)	(25)
	4	(215)
Regulatory required programs[(c)]	5	11
Total increase (decrease)	$ 9	$ (204)

(a) See Note 15 - Commitments and Contingencies of the Combined Notes to the Consolidated Financial Statements for additional information.
(b) Primarily reflects the absence of an impairment charge related to the acquisition of transmission assets in 2020.
(c) 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:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase
Depreciation and amortization[(a)]	$ 12	$ 36
Regulatory asset amortization[(b)]	(2)	16
Total increase	$ 10	$ 52

(a) Reflects ongoing capital expenditures.
(b) Includes amortization of ComEd's energy efficiency formula rate regulatory asset and amortization related to the August 2020 storm regulatory asset.

Effective income tax rates were 20.3% and 23.4% for the three months ended September 30, 2021 and 2020, respectively, and 18.8% and 31.8% for the nine months ended September 30, 2021 and 2020, respectively. See Note 10 — 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

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2021	2020		2021	2020	
Operating revenues	$ 818	$ 813	$ 5	$ 2,399	$ 2,306	$ 93
Operating expenses						
Purchased power and fuel	277	269	(8)	800	768	(32)
Operating and maintenance	263	251	(12)	706	742	36
Depreciation and amortization	86	85	(1)	259	259	—
Taxes other than income taxes	51	53	2	143	131	(12)
Total operating expenses	677	658	(19)	1,908	1,900	(8)
Operating income	141	155	(14)	491	406	85
Other income and (deductions)						
Interest expense, net	(40)	(39)	(1)	(119)	(108)	(11)
Other, net	7	6	1	20	12	8
Total other income and (deductions)	(33)	(33)	—	(99)	(96)	(3)
Income before income taxes	108	122	(14)	392	310	82
Income taxes	(3)	(16)	(13)	9	(7)	(16)
Net income	$ 111	$ 138	$ (27)	$ 383	$ 317	$ 66

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income** decreased by $27 million primarily due to an increase in storm cost activity, net of tax repair deductions.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income** increased by $66 million primarily due to favorable weather, an increase in primarily electric volume, and a decrease in storm cost activity, net of tax repair deductions.

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

	Three Months Ended September 30, 2021			Nine Months Ended September 30, 2021		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ (7)	$ (7)	$ (14)	$ 17	$ 17	$ 34
Volume	2	7	9	19	—	19
Pricing	2	4	6	(1)	(1)	(2)
Transmission	4	—	4	7	—	7
Other	—	—	—	(1)	—	(1)
	1	4	5	41	16	57
Regulatory required programs	3	(3)	—	46	(10)	36
Total increase	$ 4	$ 1	$ 5	$ 87	$ 6	$ 93

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. During the three months ended September 30, 2021 compared to the same period in 2020, Operating revenues related to weather fell due to unfavorable weather. During the nine months ended September 30, 2021 compared to the same period in 2020, revenues related to weather increased by the impact of favorable weather conditions in PECO's service territory.

Heating and cooling degree-days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree-days for a 30-year period in PECO's service territory. The changes in heating and cooling degree-days in

PECO's service territory for the three and nine months ended September 30, 2021 compared to the same period in 2020 and normal weather consisted of the following:

Heading and Cooling Degree-Days **Three Months Ended September 30,**				% Change	
	2021	2020	Normal	From 2020	2021 vs. Normal
Heating Degree-Days	4	37	25	(89.2)%	(84.0)%
Cooling Degree-Days	1,094	1,128	1,013	(3.0)%	8.0 %

				% Change	
Nine Months Ended September 30,	2021	2020	Normal	From 2020	2021 vs. Normal
Heating Degree-Days	2,710	2,594	2,865	4.5 %	(5.4)%
Cooling Degree-Days	1,517	1,504	1,402	0.9 %	8.2 %

Volume. Electric volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2021, compared to the same period in 2020, increased on a net basis due to an increase in overall usage for customers further increased by customer growth. Natural gas volume for the three and nine months ended September 30, 2021 compared to the same period in 2020, increased due to retail load growth.

Electric Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021	2020	% Change	Weather - Normal % Change(b)	2021	2020	% Change	Weather - Normal % Change(b)
Residential	4,318	4,477	(3.6) %	(1.4) %	11,201	10,874	3.0 %	1.0 %
Small commercial & industrial	2,157	2,017	6.9 %	7.7 %	5,796	5,493	5.5 %	3.9 %
Large commercial & industrial	3,880	3,791	2.3 %	2.7 %	10,627	10,393	2.3 %	1.8 %
Public authorities & electric railroads	155	145	6.9 %	7.2 %	425	407	4.4 %	4.3 %
Total electric retail deliveries(a)	10,510	10,430	0.8 %	2.0 %	28,049	27,167	3.2 %	2.0 %

	As of September 30,	
Number of Electric Customers	2021	2020
Residential	1,514,836	1,505,080
Small commercial & industrial	155,006	154,183
Large commercial & industrial	3,108	3,105
Public authorities & electric railroads	10,271	10,149
Total	1,683,221	1,672,517

(a) Reflects delivery volumes from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Natural Gas Deliveries to Customers (in mmcf)	Three Months Ended September 30,				Nine Months Ended September 30,			
	2021	2020	% Change	Weather - Normal % Change(b)	2021	2020	% Change	Weather - Normal % Change(b)
Residential	2,244	2,121	5.8 %	8.2 %	27,945	25,867	8.0 %	0.8 %
Small commercial & industrial	1,926	2,157	(10.7)%	(11.7)%	15,217	13,020	16.9 %	7.5 %
Large commercial & industrial	4	9	(55.6)%	1.3 %	13	20	(35.0)%	7.7 %
Transportation	5,356	5,269	1.7 %	5.0 %	18,474	17,553	5.2 %	4.0 %
Total natural gas retail deliveries(a)	9,530	9,556	(0.3)%	2.0 %	61,649	56,460	9.2 %	3.3 %

Number of Natural Gas Customers	As of September 30, 2021	2020
Residential	495,752	490,158
Small commercial & industrial	44,435	44,138
Large commercial & industrial	6	5
Transportation	670	715
Total	540,863	535,016

(a) Reflects delivery volumes from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges.

(b) Reflects the change in delivery volumes assuming normalized weather based on the historical 30-year average.

Pricing for the three and nine months ended September 30, 2021 compared to the same period in 2020 remained relatively consistent.

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.

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.

Other revenue which primarily includes revenue related to late payment charges. Other revenues for the three and nine months ended September 30, 2021 compared to the same period in 2020, remained relatively consistent.

See Note 5 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

The increase of $8 million and the increase of $32 million for the three and nine months ended September 30, 2021 compared to the same period in 2020, respectively, in Purchased power and fuel expense is partially offset in Operating revenues as part of regulatory required programs.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Storm-related costs[a]	$ 5	(54)
Credit loss expense	10	(2)
Regulatory Required Programs	(6)	(7)
BSC costs	5	12
Labor, other benefits, contracting and materials	(4)	19
Pension and non-pension post retirement benefit expense	—	1
Other	2	(5)
Total increase (decrease)	$ 12	$ (36)

(a) YTD primarily reflects the absence of costs in 2021 due to the June and August 2020 storms.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[a]	$ 6	$ 11
Regulatory asset amortization	(5)	(11)
Total increase	$ 1	$ —

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

Interest expense, net increased $1 million and $11 million for the three and nine months ended September 30, 2021 compared to the same period in 2020, respectively, primarily due to the issuance of debt in March 2021 and June 2020.

Effective income tax rates were (2.8)% and (13.1)% for the three months ended September 30, 2021 and 2020 respectively, and 2.3% and (2.3)% for the nine months ended September 30, 2021 and 2020, respectively. See Note 10 — 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

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2021	2020		2021	2020	
Operating revenues	$ 770	$ 731	$ 39	$ 2,426	$ 2,284	$ 142
Operating expenses						
Purchased power and fuel	290	250	(40)	840	731	(109)
Operating and maintenance	205	191	(14)	595	567	(28)
Depreciation and amortization	142	133	(9)	434	405	(29)
Taxes other than income taxes	72	68	(4)	211	200	(11)
Total operating expenses	709	642	(67)	2,080	1,903	(177)
Operating income	61	89	(28)	346	381	(35)
Other income and (deductions)						
Interest expense, net	(36)	(34)	(2)	(103)	(99)	(4)
Other, net	7	6	1	23	17	6
Total other income and (deductions)	(29)	(28)	(1)	(80)	(82)	2
Income before income taxes	32	61	(29)	266	299	(33)
Income taxes	(4)	8	12	(24)	26	50
Net income	$ 36	$ 53	$ (17)	$ 290	$ 273	$ 17

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income** decreased by $17 million primarily related to an increase in depreciation and amortization expense and an increase in various expenses, partially offset by favorable impacts of the multi-year plan.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income** increased by $17 million primarily due to favorable impacts of the multi-year plan, partially offset by an increase in depreciation and amortization expense and an increase in storm costs. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric and natural gas distribution multi-year plan.

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

	Three Months Ended September 30, 2021			Nine Months Ended September 30, 2021		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution	$ 1	$ 1	$ 2	$ 7	$ 2	$ 9
Transmission	(6)	—	(6)	23	—	23
Other	7	—	7	5	1	6
	2	1	3	35	3	38
Regulatory required programs	29	7	36	70	34	104
Total increase	$ 31	$ 8	$ 39	$ 105	$ 37	$ 142

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 bill stabilization adjustment (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.

Number of Electric Customers	As of September 30, 2021	As of September 30, 2020
Residential	1,194,254	1,187,498
Small commercial & industrial	114,814	114,038
Large commercial & industrial	12,584	12,428
Public authorities & electric railroads	268	267
Total	1,321,920	1,314,231

Number of Natural Gas Customers	As of September 30, 2021	As of September 30, 2020
Residential	649,745	644,872
Small commercial & industrial	38,216	38,173
Large commercial & industrial	6,167	6,083
Total	694,128	689,128

Distribution Revenue increased for the three and nine months ended September 30, 2021, compared to the same period in 2020, due to 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 decreased for the three months ended September 30, 2021, compared to the same period in 2020, primarily due to decreases in Operating and maintenance expense recoveries in 2021. Transmission revenue increased for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission related income tax regulatory liabilities.

Other Revenue includes revenue related to late payment charges, mutual assistance, off-system sales, and service application fees. Other revenue increased for both the three and nine months ended September 30, 2021, compared to the same period in 2020, as BGE had temporarily suspended customer disconnections for non-payment and temporarily ceased new late fees for customers in 2020 which has resumed in 2021.

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 either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore BGE 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 increase of $40 million and $109 million for the three and nine months ended September 30, 2021 compared to the same period in 2020, 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:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Labor, other benefits, contracting, and materials	$ 3	$ 5
Storm-related costs	3	10
Pension and non-pension postretirement benefits expense	—	1
BSC costs	7	13
Credit loss expense	1	(5)
Other	(2)	(1)
	12	23
Regulatory required programs	2	5
Total increase	$ 14	$ 28

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[(a)]	$ 12	$ 31
Regulatory asset amortization	1	1
Regulatory required programs	(4)	(3)
Total increase	$ 9	$ 29

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

Taxes other than income taxes increased for the three and nine months ended September 30, 2021 compared to the same period in 2020, primarily due to higher property taxes.

Effective income tax rates were (12.5)% and 13.1% for the three months ended September 30, 2021 and 2020, respectively, and (9.0)% and 8.7% for the nine months ended September 30, 2021 and 2020, respectively. The change is primarily due to the multi-year plan which resulted in the acceleration of certain income tax benefits and the April 24, 2020 settlement agreement of ongoing transmission related income tax regulatory liabilities. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric and natural gas distribution multi-year plan, Note 3 — Regulatory Matters of the 2020 Exelon Form 10-K for additional information on the April 24, 2020 settlement agreement, and Note 10 — 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 three and nine months ended September 30, 2021 compared to the same period in 2020. See the Results of Operations for Pepco, DPL, and ACE for additional information.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Favorable Variance	2021	2020	Favorable Variance
PHI	$ 266	$ 216	$ 50	$ 535	$ 418	$ 117
Pepco	130	118	12	264	227	37
DPL	50	27	23	135	91	44
ACE	90	75	15	141	106	35
Other[(a)]	(4)	(4)	—	(5)	(6)	1

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

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income** increased by $50 million primarily due to higher distribution rates, customer growth at Pepco, higher transmission revenues due to an increase in capital investments in ACE's service territories, and a decrease in storm costs due to the August 2020 storms in Delaware at DPL, partially offset by an increase in depreciation and amortization expense at Pepco.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income** increased by $117 million primarily due to higher distribution rates, higher transmission revenues due to an increase in capital investments in DPL's and ACE's service territories, higher distribution revenues due to an increase in volume in ACE's service territory, favorable weather conditions in DPL's Delaware service territory, customer growth at Pepco, a decrease in credit loss expense at Pepco and DPL, and a decrease in storm costs due to the August 2020 storms in Delaware at DPL, partially offset by an increase in depreciation and amortization expense at Pepco.

Results of Operations — Pepco

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	2020	Favorable (Unfavorable) Variance	2021	2020	Favorable (Unfavorable) Variance
Operating revenues	$ 660	$ 611	$ 49	$ 1,736	$ 1,650	$ 86
Operating expenses						
Purchased power	172	163	(9)	471	467	(4)
Operating and maintenance	120	106	(14)	341	336	(5)
Depreciation and amortization	104	96	(8)	302	282	(20)
Taxes other than income taxes	105	100	(5)	282	279	(3)
Total operating expenses	501	465	(36)	1,396	1,364	(32)
Operating income	159	146	13	340	286	54
Other income and (deductions)						
Interest expense, net	(35)	(35)	—	(104)	(103)	(1)
Other, net	12	10	2	37	28	9
Total other income and (deductions)	(23)	(25)	2	(67)	(75)	8
Income before income taxes	136	121	15	273	211	62
Income taxes	6	3	(3)	9	(16)	(25)
Net income	$ 130	$ 118	$ 12	$ 264	$ 227	$ 37

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income** increased by $12 million primarily due to higher distribution rates and customer growth, partially offset by an increase in depreciation and amortization expense.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income** increased by $37 million primarily due to higher distribution rates, customer growth, a decrease in credit loss expense, and decreases in various operating expenses, partially offset by an increase in depreciation and amortization expense.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase	Increase
Distribution	$ 18	$ 23
Transmission	6	28
Other	4	3
	28	54
Regulatory required programs	21	32
Total increase	$ 49	$ 86

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 bill stabilization adjustment (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.

Number of Electric Customers	As of September 30, 2021	2020
Residential	839,574	828,578
Small commercial & industrial	53,849	53,813
Large commercial & industrial	22,586	22,485
Public authorities & electric railroads	179	167
Total	916,188	905,043

Distribution Revenue increased for both the three and nine months ended September 30, 2021 compared to the same period in 2020 due to higher distribution rates that became effective in Maryland and District of Columbia in Q3 2021 and customer growth.

Transmission Revenues. 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 three months ended September 30, 2021 compared to the same period in 2020, primarily due to increases in underlying costs. Transmission revenue increased for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission related income tax regulatory liabilities and increases in underlying costs.

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 either acts as the billing agent or the competitive supplier separately bills its own customers, 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 $9 million and $4 million for the three and nine months ended September 30, 2021, respectively compared to the same period in 2020, respectively, 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:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Storm-related costs	$ 5	$ 5
BSC and PHISCO costs	2	1
Credit loss expense	—	(4)
Pension and non-pension postretirement benefits expense	(1)	(3)
Labor, other benefits, contracting and materials	(2)	(13)
Other	6	14
	10	—
Regulatory required programs	4	5
Total increase	$ 14	$ 5

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[(a)]	$ 5	$ 13
Regulatory asset amortization	(3)	(10)
Regulatory required programs	6	17
Total increase	$ 8	$ 20

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

Effective income tax rates were 4.4% and 2.5% for the three months ended September 30, 2021 and 2020, respectively, and 3.3% and (7.6)% for the nine months ended September 30, 2021 and 2020, respectively. For the nine months ended September 30, 2021, the change is primarily due to the April 24, 2020 settlement agreement of ongoing transmission related income tax regulatory liabilities, partially offset by the multi-year plan which resulted in the acceleration of certain income tax benefits. See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the three-year electric distribution multi-year plan, Note 3 — Regulatory Matters of the 2020 Exelon Form 10-K for additional information on the April 24, 2020 settlement agreement, and Note 10 — 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

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2021	2020		2021	2020	
Operating revenues	$ 360	$ 337	$ 23	$ 1,040	$ 954	$ 86
Operating expenses						
Purchased power and fuel	138	131	(7)	402	379	(23)
Operating and maintenance	87	101	14	249	272	23
Depreciation and amortization	53	48	(5)	157	143	(14)
Taxes other than income taxes	17	16	(1)	50	49	(1)
Total operating expenses	295	296	1	858	843	(15)
Operating income	65	41	24	182	111	71
Other income and (deductions)						
Interest expense, net	(15)	(15)	—	(47)	(47)	—
Other, net	3	2	1	9	7	2
Total other income and (deductions)	(12)	(13)	1	(38)	(40)	2
Income before income taxes	53	28	25	144	71	73
Income taxes	3	1	(2)	9	(20)	(29)
Net income	$ 50	$ 27	$ 23	$ 135	$ 91	$ 44

***Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020*.** **Net income** increased by $23 million primarily due to higher electric distribution rates and a decrease in storm costs due to the August 2020 storms in Delaware.

***Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020*.** **Net income** increased by $44 million primarily due to higher electric distribution rates, a decrease in storm costs due to the August 2020 storms in Delaware, higher transmission revenues due to an increase in capital investments, a decrease in credit loss expense, and favorable weather conditions at DPL's Delaware electric service territories.

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

	Three Months Ended September 30, 2021			Nine Months Ended September 30, 2021		
	(Decrease) Increase			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ —	$ (2)	$ (2)	$ 4	$ —	$ 4
Volume	(2)	1	(1)	—	(1)	(1)
Distribution	11	(1)	10	20	1	21
Transmission	5	—	5	33	—	33
Other	—	1	1	1	—	1
	14	(1)	13	58	—	58
Regulatory required programs	9	1	10	27	1	28
Total increase	$ 23	$ —	$ 23	$ 85	$ 1	$ 86

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 bill stabilization adjustment (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.

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 three months ended September 30, 2021 compared to the same period in 2020, Operating revenues related to weather decreased due to the impact of unfavorable weather conditions in DPL's Delaware natural gas service territory. During the nine months ended September 30, 2021 compared to the same period in 2020, Operating revenues related to weather increased due to the impact of favorable weather conditions in DPL's Delaware electric 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 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 three and nine months ended September 30, 2021 compared to same period in 2020 and normal weather consisted of the following:

Delaware Electric Service Territory				% Change	
Three Months Ended September 30,	2021	2020	Normal	2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	11	55	29	(80.0)%	(62.1)%
Cooling Degree-Days	969	961	894	0.8 %	8.4 %

				% Change	
Nine Months Ended September 30,	2021	2020	Normal	2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	2,848	2,664	2,993	6.9 %	(4.8)%
Cooling Degree-Days	1,333	1,260	1,228	5.8 %	8.6 %

Delaware Natural Gas Service Territory				% Change	
Three Months Ended September 30,	2021	2020	Normal	2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	11	55	38	(80.0)%	(71.1)%

				% Change	
Nine Months Ended September 30,	2021	2020	Normal	2021 vs. 2020	2021 vs. Normal
Heating Degree-Days	2,848	2,664	3,025	6.9 %	(5.9)%

Volume, exclusive of the effects of weather, remained relatively consistent for the three and nine months ended September 30, 2021 compared to the same period in 2020.

Electric Retail Deliveries to Delaware Customers (in GWhs)	Three Months Ended September 30,		% Change	Weather - Normal % Change[b]	Nine Months Ended September 30,		% Change	Weather - Normal % Change[b]
	2021	2020			2021	2020		
Residential	973	1,028	(5.4)%	(5.1)%	2,530	2,474	2.3 %	(0.3)%
Small commercial & industrial	412	373	10.5 %	10.8 %	1,111	943	17.8 %	16.3 %
Large commercial & industrial	860	775	11.0 %	11.2 %	2,359	2,408	(2.0)%	(2.5)%
Public authorities & electric railroads	7	6	16.7 %	21.6 %	26	23	13.0 %	11.0 %
Total electric retail deliveries[a]	2,252	2,182	3.2 %	3.6 %	6,026	5,848	3.0 %	1.5 %

Number of Total Electric Customers (Maryland and Delaware)	As of September 30, 2021	2020
Residential	476,008	471,875
Small commercial & industrial	62,990	62,291
Large commercial & industrial	1,215	1,234
Public authorities & electric railroads	605	610
Total	540,818	536,010

(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)	Three Months Ended September 30, 2021	2020	% Change	Weather - Normal % Change[(b)]	Nine Months Ended September 30, 2021	2020	% Change	Weather - Normal % Change[(b)]
Residential	399	441	(9.5)%	8.8 %	5,507	5,256	4.8 %	(1.2) %
Small commercial & industrial	352	339	3.8 %	13.9 %	2,647	2,567	3.1 %	(2.2) %
Large commercial & industrial	395	402	(1.7)%	(1.8) %	1,247	1,265	(1.4)%	(1.6) %
Transportation	1,303	1,231	5.8 %	7.2 %	4,997	4,811	3.9 %	2.3 %
Total natural gas deliveries[(a)]	2,449	2,413	1.5 %	6.9 %	14,398	13,899	3.6 %	0.3 %

Number of Delaware Natural Gas Customers	As of September 30, 2021	2020
Residential	127,740	126,659
Small commercial & industrial	9,935	9,885
Large commercial & industrial	21	17
Transportation	158	160
Total	137,854	136,721

(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 three months ended September 30, 2021 compared to the same period in 2020 primarily due to higher electric distribution rates in Delaware that became effective in October 2020. Distribution revenue increased for the nine months ended September 30, 2021 compared to the same period in 2020 primarily due to higher electric distribution rates in Maryland that became effective in July 2020 and higher electric distribution rates in Delaware that became effective in October 2020.

Transmission Revenues. 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 three months ended September 30, 2021 compared to the same period in 2020, primarily due to increases in underlying costs. Transmission revenue increased for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission related income tax regulatory liabilities and increases in underlying costs and capital investments.

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. Customers have the choice to purchase electricity from competitive electric generation 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 from competitive suppliers, DPL either acts as the billing agent or the competitive supplier separately bills its own customers, and therefore DPL does not record Operating revenues or Purchased power and fuel expense related to the electricity. For customers that choose to purchase electric generation from DPL, DPL is permitted to recover the electricity and REC procurement costs from customers with a slight mark-up and therefore records the amounts related to the electricity and RECs in Operating revenues and Purchased power and fuel expense. DPL recovers natural gas costs without mark-up and records the amount in Operating revenues and Purchased power and fuel expense.

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

The increase of $7 million and $23 million for the three and nine months ended September 30, 2021, compared to the same period in 2020, respectively, 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:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	(Decrease) Increase	(Decrease) Increase
Storm-related costs	$ (16)	$ (20)
Pension and non-pension postretirement benefits expense	(1)	(2)
Credit loss expense	(1)	(7)
Labor, other benefits, contracting and materials	2	(1)
BSC and PHISCO costs	3	5
Other	(1)	3
	(14)	(22)
Regulatory required programs	—	(1)
Total decrease	$ (14)	$ (23)

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase	Increase (Decrease)
Depreciation and amortization[(a)]	$ 3	$ 10
Regulatory asset amortization	—	(1)
Regulatory required programs	2	5
Total increase	$ 5	$ 14

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

Effective income tax rates were 5.7% and 3.6% for the three months ended September 30, 2021 and 2020, respectively, and 6.3% and (28.2)% for the nine months ended September 30, 2021 and 2020, respectively. For the nine months ended September 30, 2021, compared to the same period in 2020, the change is primarily due to the April 24, 2020 settlement agreement of ongoing transmission related income tax regulatory liabilities. See Note 3 — Regulatory Matters of the 2020 Exelon Form 10-K for additional information on the April 24, 2020 settlement agreement, and Note 10 — 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 — ACE

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2021	2020		2021	2020	
Operating revenues	$ 451	$ 420	$ 31	$ 1,080	$ 952	$ 128
Operating expenses						
Purchased power	230	211	(19)	541	469	(72)
Operating and maintenance	81	77	(4)	231	238	7
Depreciation and amortization	46	48	2	133	134	1
Taxes other than income taxes	2	2	—	6	6	—
Total operating expenses	359	338	(21)	911	847	(64)
Gain on sales of assets	—	—	—	—	2	(2)
Operating income	92	82	10	169	107	62
Other income and (deductions)						
Interest expense, net	(14)	(15)	1	(43)	(45)	2
Other, net	1	1	—	3	5	(2)
Total other income and (deductions)	(13)	(14)	1	(40)	(40)	—
Income before income taxes	79	68	11	129	67	62
Income taxes	(11)	(7)	4	(12)	(39)	(27)
Net income	$ 90	$ 75	$ 15	$ 141	$ 106	$ 35

Three Months Ended September 30, 2021 Compared to Three Months Ended September 30, 2020. **Net income** increased by $15 million primarily due to higher distribution rates and higher transmission revenues due to an increase in capital investments.

Nine Months Ended September 30, 2021 Compared to Nine Months Ended September 30, 2020. **Net income** increased by $35 million primarily due to higher distribution rates, higher distribution revenues due to an increase in volume in ACE's service territory, and higher transmission revenues due to an increase in capital investments.

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	(Decrease) Increase	Increase (Decrease)
Weather	$ (3)	$ —
Volume	3	19
Distribution	4	3
Transmission	10	46
Other	(1)	(1)
	13	67
Regulatory required programs	18	61
Total increase	$ 31	$ 128

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 Conservation Incentive Program (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.

Weather. Prior to the third quarter of 2021, the demand for electricity was affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the three months ended September 30, 2021 compared to the same period in 2020, Operating revenues related to weather decreased due to the absence of impacts in the third quarter of 2021 as a result of the CIP. During the nine months ended September 30, 2021 compared to the same period in 2020, Operating revenues related to weather remained relatively consistent.

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 ACE’s service territory. The changes in heating and cooling degree days in ACE’s service territory for the nine months ended September 30, 2021 compared to same period in 2020 and normal weather consisted of the following:

Heating and Cooling Degree-Days Nine Months Ended September 30,	2021	2020	Normal	% Change 2021 vs. 2020	% Change 2021 vs. Normal
Heating Degree-Days	2,884	2,618	3,042	10.2 %	(5.2)%
Cooling Degree-Days	1,246	1,300	1,165	(4.2)%	7.0 %

Volume, exclusive of the effects of weather, increased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to customer growth and usage.

Electric Retail Deliveries to Customers (in GWhs)	Nine Months Ended September 30, 2021	Nine Months Ended September 30, 2020	% Change	Weather - Normal % Change[(b)]
Residential	3,443	3,193	7.8 %	7.1 %
Small commercial & industrial	1,073	967	11.0 %	11.1 %
Large commercial & industrial	2,351	2,287	2.8 %	3.1 %
Public authorities & electric railroads	33	33	— %	0.7 %
Total electric retail deliveries[(a)]	6,900	6,480	6.5 %	6.3 %

Number of Electric Customers	As of September 30, 2021	As of September 30, 2020
Residential	499,775	497,222
Small commercial & industrial	61,838	61,521
Large commercial & industrial	3,209	3,305
Public authorities & electric railroads	707	694
Total	565,529	562,742

(a) Reflects delivery volumes from customers purchasing electricity directly from ACE 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.

Distribution Revenue increased for the three and nine months ended September 30, 2021 compared to the same period in 2020 due to higher distribution rates.

Transmission Revenues. 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 three months ended September 30, 2021 compared to the same period in 2020, primarily due to increases in capital investment. Transmission revenue increased for the nine months ended September 30, 2021 compared to the same period in 2020, primarily due to the reduction in revenue in 2020 due to the settlement agreement of ongoing transmission related income tax regulatory liabilities and increases in capital investment.

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 either acts as the billing agent or the competitive supplier separately bills its own customers, 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 $19 million and $72 million for the three and nine months ended September 30, 2021 compared to the same period in 2020, respectively, 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:

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
BSC and PHISCO costs	$ 2	$ 4
Labor, other benefits, contracting and materials	2	(2)
Pension and non-pension postretirement benefits expense	—	(1)
Storm-related costs	(2)	(5)
Other	(3)	(2)
	(1)	(6)
Regulatory required programs[(a)]	5	(1)
Total increase (decrease)	$ 4	$ (7)

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

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
	Increase (Decrease)	Increase (Decrease)
Depreciation and amortization[(a)]	$ 4	$ 11
Regulatory asset amortization	—	(1)
Regulatory required programs	(6)	(11)
Total decrease	$ (2)	$ (1)

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

Effective income tax rates were (13.9)% and (10.3)% for the three months ended September 30, 2021 and 2020, respectively, and (9.3)% and (58.2)% for the nine months ended September 30, 2021 and 2020, respectively. For the nine months ended September 30, 2021, compared to the same period in 2020, the change is primarily due to the April 24, 2020 settlement agreement of ongoing transmission related income tax regulatory liabilities, partially offset by the July 14, 2021 settlement which allowed ACE to retain certain tax benefits. See Note 3 — Regulatory Matters of the 2020 Exelon Form 10-K for additional information on the April 24, 2020 settlement. See Note 3 — Regulatory Matters and Note 10 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information on the July 14, 2021 settlement agreement and regarding the components of the effective income tax rates, respectively.

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, the sale of certain receivables, 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, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). 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 $10.3 billion. 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” section below for additional information. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs, and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and OPEB obligations, and invest in new and existing ventures. 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. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants’ debt and credit agreements.

NRC Minimum Funding Requirements (Exelon and Generation)

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are typically based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant’s owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 8 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional information.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT funds could appreciate in value. A shortfall could require that Generation address the shortfall by providing additional financial assurances such as surety bonds, letters of credit, or parent company guarantees for Generation’s share of the funding assurance. However, the amount of any assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT fund investment performance going forward. No later than two years after shutting down a plant, Generation must submit a PSDAR to the NRC that includes the planned option for decommissioning the site. As a result of the early retirement reversal, additional financial assurance is no longer required for Byron.

Upon issuance of any required financial assurance, subject to satisfying various regulatory preconditions, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, under the regulations, the NRC must approve an exemption in order for Generation to utilize the NDT funds to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs, if applicable). If a unit does not receive this exemption, those costs would be borne by Generation without reimbursement from or access to the NDT funds.

As of September 30, 2021, Generation is not required to provide any additional financial assurances for TMI Unit 1 under the SAFSTOR scenario which is the planned decommissioning option as described in the TMI Unit 1 PSDAR filed by Generation with the NRC on April 5, 2019. On October 16, 2019, the NRC granted Generation's exemption request to use the TMI Unit 1 NDT funds for spent fuel management costs. An additional exemption request to allow the TMI Unit 1 NDT funds to be used for site restoration costs was submitted to the NRC on May 20, 2021 and is pending NRC review.

Cash Flows from Operating Activities (All Registrants)

Generation’s cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation’s future cash flows from operating activities may be affected by future demand for, and market prices of, energy and its ability to continue to produce and supply power at competitive costs, as well as to obtain collections from customers and the sale of certain receivables.

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.

See Note 3 — Regulatory Matters and Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2020 Form 10-K for additional information on regulatory and legal proceedings and proposed legislation.

The following table provides a summary of the change in cash flows from operating activities for the nine months ended September 30, 2021 and 2020 by Registrant:

(Decrease) increase in cash flows from operating activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net income	$ (78)	$ (607)	$ 305	$ 66	$ 17	$ 117	$ 37	$ 44	$ 35
Adjustments to reconcile net income to cash:									
Non-cash operating activities	(899)	(527)	(216)	1	(4)	(22)	8	(10)	(23)
Pension and non-pension postretirement benefit contributions	(22)	12	(31)	3	(2)	(8)	(1)	—	—
Income taxes	281	65	13	7	(43)	31	1	31	6
Changes in working capital and other noncurrent assets and liabilities	(775)	(611)	(28)	(75)	(25)	(92)	(134)	28	27
Option premiums paid, net	(55)	(55)	—	—	—	—	—	—	—
Collateral received, net	1,467	1,334	65	—	—	—	—	—	—
(Decrease) increase in cash flows from operating activities	$ (81)	$ (389)	$ 108	$ 2	$ (57)	$ 26	$ (89)	$ 93	$ 45

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. In addition, significant operating cash flow impacts for the Registrants for the nine months ended September 30, 2021 and 2020 were as follows:

- See Note 18 — 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**.

- See Note 10 — 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 working capital and other noncurrent assets and liabilities** include a decrease in Accounts receivable resulting from the impact of cash received at Exelon and Generation in 2020 related to the revolving accounts receivable financing arrangement entered into on April 8, 2020 and an increase in Accounts payable and accrued expenses resulting from the impact of certain penalties for natural gas delivery associated with the February 2021 extreme cold weather event at Exelon and Generation. See Note 6 – Accounts Receivable and Note 3 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the sales of customer accounts receivable and on the February 2021 extreme cold weather event, respectively.
- Depending upon whether Generation is in a net mark-to-market liability or asset position, **collateral** may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the over-the-counter markets. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants' collateral.

Cash Flows from Investing Activities (All Registrants)

The following table provides a summary of the change in cash flows from investing activities for the nine months ended September 30, 2021 and 2020 by Registrant:

Increase (decrease) in cash flows from investing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Capital expenditures	$ (364)	$ 126	$ (140)	$ (54)	$ (69)	$ (227)	$ (129)	$ (42)	$ (55)
Proceeds from NDT fund sales, net	(66)	(66)	—	—	—	—	—	—	—
Proceeds from sales of assets and businesses	755	756	—	—	—	—	—	—	—
Changes in intercompany money pool	—	—	—	(68)	—	—	117	—	—
Collection of DPP	534	534	—	—	—	—	—	—	—
Other investing activities	42	—	20	1	13	(4)	1	4	(4)
Increase (decrease) in cash flows from investing activities	$ 901	$ 1,350	$ (120)	$ (121)	$ (56)	$ (231)	$ (11)	$ (38)	$ (59)

Significant investing cash flow impacts for the Registrants for nine months ended September 30, 2021 and 2020 were as follows:

- Variances in **capital expenditures** are primarily due to the timing of cash expenditures for capital projects. Refer below for additional information on projected capital expenditure spending.
- **Proceeds from sales of assets and businesses** increased primarily due to the sale of a significant portion of Generation's solar business and a biomass facility and proceeds received on sales of equity investments. See Note 2 – Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the sale of Generation's solar business and biomass facility.
- Changes in **intercompany money pool** are driven by short-term borrowing needs. Refer below for more information regarding the intercompany money pool.
- See Note 6 – Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information on the **Collection of DPP**.

Capital Expenditure Spending

As of September 30, 2021, the most recent estimates of capital expenditures for plant additions and improvements for 2021 are as follows:

(In millions)	Transmission	Distribution	Gas	Total
Exelon	N/A	N/A	N/A	$ 8,175
Generation	N/A	N/A	N/A	1,450
ComEd	475	1,925	N/A	2,400
PECO	150	775	350	1,275
BGE	325	475	400	1,200
PHI	550	1,125	75	1,750
Pepco	250	650	N/A	900
DPL	100	250	75	425
ACE	200	225	N/A	425

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Cash Flows from Financing Activities (All Registrants)

The following table provides a summary of the change in cash flows from financing activities for the nine months ended September 30, 2021 and 2020 by Registrant:

Increase (decrease) in cash flows from financing activities	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Changes in short-term borrowings, net	$ 825	$ 320	$ (334)	$ —	$ 76	$ 127	$ 87	$ (68)	$ 108
Long-term debt, net	190	1,271	300	100	(100)	13	(24)	26	11
Changes in intercompany money pool	—	(285)	—	(40)	—	(14)	—	—	(117)
Dividends paid on common stock	(2)	—	(6)	1	(33)	—	(47)	(7)	(169)
Acquisition of noncontrolling interest	(885)	(885)	—	—	—	—	—	—	—
Distributions to member	—	33	—	—	—	(154)	—	—	—
Contributions from parent/member	—	—	105	166	(27)	174	(18)	8	186
Other financing activities	12	3	(2)	(4)	2	(2)	2	(3)	(4)
Increase (decrease) in cash flows from financing activities	$ 140	$ 457	$ 63	$ 223	$ (82)	$ 144	$ —	$ (44)	$ 15

Significant financing cash flow impacts for the Registrants for the nine months ended September 30, 2021 and 2020 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on short-term borrowings.
- **Long-term debt, net**, varies due to debt issuances and redemptions each year. Refer to Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on debt issuances. Refer to the debt redemptions table below for additional information.
- **Changes in intercompany money pool** are driven by short-term borrowing needs. Refer below for more information regarding the intercompany money pool.

- 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 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2020 Form 10-K for additional information on dividend restrictions. See below for quarterly dividends declared.
- See Note 2 – Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information related to the **acquisition** of CENG noncontrolling interest.
- For the nine months ended September 30, 2021, **other financing activities** primarily consists of debt issuance costs. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants’ debt issuances.

Debt

See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants’ debt issuances.

During the nine months ended September 30, 2021, the following long-term debt was retired and/or redeemed:

Company[a]	Type	Interest Rate	Maturity	Amount
Exelon	Senior Notes	2.45 %	April 15, 2021	$ 300
Exelon	Long-Term Software License Agreement	3.95 %	May 1, 2024	24
Exelon	Long-Term Software License Agreements	3.62 %	December 1, 2025	1
Generation	Continental Wind Nonrecourse Debt[b]	6.00 %	February 28, 2033	35
Generation	EGR IV Nonrecourse Debt[b]	3 month LIBOR + 2.50 % [c]	December 15, 2027	17
Generation	SolGen Nonrecourse Debt[b]	3.93 %	September 30, 2036	7
Generation	Antelope Valley DOE Nonrecourse Debt[b]	2.29% - 3.56%	January 5, 2037	13
Generation	West Medway II Nonrecourse Debt[b]	LIBOR + 3% [d]	March 31, 2026	8
Generation	RPG Nonrecourse Debt[a]	4.11 %	March 31, 2035	9
ComEd	First Mortgage Bonds	3.40 %	September 1, 2021	350
PECO	First Mortgage Bonds	1.70 %	September 15, 2021	300
BGE	Senior Notes	3.50 %	November 15, 2021	300
ACE	First Mortgage Bonds	4.35 %	April 1, 2021	200
ACE	Tax-Exempt First Mortgage Bonds	6.80 %	March 1, 2021	39
ACE	Transition Bonds	5.55 %	October 20, 2021	15

(a) On October 5, 2021, Generation redeemed $11 million of 2.29% - 3.56% Antelope Valley DOE nonrecourse debt. On October 20, 2021, ACE redeemed $6 million of 5.55% transition bonds.
(b) See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on nonrecourse debt.
(c) The interest rate was amended to 3 month LIBOR + 2.50 % on June 16, 2021.
(d) The nonrecourse debt has an average blended interest rate.

Dividends

Quarterly dividends declared by the Exelon Board of Directors during the nine months ended September 30, 2021 and for the fourth quarter of 2021 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2021	February 21, 2021	March 8, 2021	March 15, 2021	$ 0.3825
Second Quarter 2021	April 27, 2021	May 14, 2021	June 10, 2021	$ 0.3825
Third Quarter 2021	July 27, 2021	August 13, 2021	September 10, 2021	$ 0.3825
Fourth Quarter 2021	October 29, 2021	November 15, 2021	December 10, 2021	$ 0.3825

(a) Exelon's Board of Directors approved an updated dividend policy for 2021. The 2021 quarterly dividend will remain the same as the 2020 dividend of $0.3825 per share.

Credit Matters (All Registrants)

The Registrants fund liquidity needs for capital investment, 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 $10.3 billion in aggregate total commitments of which $7.7 billion was available to support additional commercial paper as of September 30, 2021, and of which no financial institution has more than 7% 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 the nine months ended September 30, 2021 to fund their short-term liquidity needs, when necessary. Generation used its available credit facilities to manage short-term liquidity needs as a result of the impacts of the February 2021 extreme cold weather event and continues to believe it has sufficient cash on hand and available capacity on its revolver to meet its liquidity requirements. 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 have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising, and merger activity. See PART I. ITEM 1A. RISK FACTORS of the Exelon 2020 Form 10-K 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. If Generation lost its investment grade credit rating as of September 30, 2021, it would have been required to provide incremental collateral of approximately $3.0 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts, and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within the $4.3 billion of available credit capacity of its revolver.

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 September 30, 2021 and available credit facility capacity prior to any incremental collateral at September 30, 2021:

	PJM Credit Policy Collateral	Other Incremental Collateral Required(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 27	$ —	$ 998
PECO	1	23	600
BGE	4	46	600
Pepco	3	—	260
DPL	4	11	278
ACE	1	—	75

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

Project Financing (Exelon and Generation)

Project financing is used to help mitigate risk of specific generating assets. Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by the specific asset or portfolio of assets. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful lives. Additionally, project financing has credit facilities. Refer to Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on credit facilities and nonrecourse debt.

Credit Facilities (All Registrants)

Exelon Corporate, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the Registrants’ short-term borrowing activity. See Note 17 — Debt and Credit Agreements of the Exelon 2020 Form 10-K for additional information on the Registrants’ credit facilities.

Security Ratings (All Registrants)

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

The credit ratings for Exelon Corporate and the Utility Registrants did not change for the nine months ended September 30, 2021.

On February 24, 2021, S&P lowered Generation’s senior unsecured debt rating to ‘BBB-‘ from ‘BBB’ in response to the financial impacts of the February 2021 weather event and Texas-based generating assets outages. See Significant 2021 Transactions and Developments for additional information. The S&P ratings changes did not materially impact Generation's financial statements. Furthermore, there were no material increases in required collateral or financial assurances or material impacts to our anticipated access to liquidity or cost of financing.

Intercompany Money Pool (All Registrants)

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 September 30, 2021, are presented in the following table. ACE had no activity within the PHI Intercompany Money Pool for the nine months ended September 30, 2021.

	During the Nine Months Ended September 30, 2021		As of September 30, 2021
Exelon Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 735	$ —	$ 239
Generation	—	(426)	—
PECO	303	(100)	—
BSC	—	(435)	(273)
PHI Corporate	—	(40)	(16)
PCI	60	—	50

	During the Nine Months Ended September 30, 2021		As of September 30, 2021
PHI Intercompany Money Pool	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Pepco	$ —	$ (30)	$ —
DPL	30	—	—

Shelf Registration Statements (All Registrants)

Exelon, Generation, and the Utility Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2022. 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 (All Registrants)

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

	As of September 30, 2021					
	Short-term Financing Authority[(a)(b)]			Remaining Long-term Financing Authority[(a)]		
	Commission	**Expiration Date**	**Amount**	**Commission**	**Expiration Date**	**Amount**
ComEd[(c)]	FERC	December 31, 2021	$ 2,500	ICC	February 1, 2023	$ 93
PECO[(d)]	FERC	December 31, 2021	1,500	PAPUC	December 31, 2021	475
BGE	FERC	December 31, 2021	700	MDPSC	N/A	500
Pepco	FERC	December 31, 2021	500	MDPSC / DCPSC	December 31, 2022	625
DPL	FERC	December 31, 2021	500	MDPSC / DPSC	December 31, 2022	172
ACE	NJBPU	December 31, 2021	350	NJBPU	December 31, 2022	250

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) On October 15, 2021, ComEd, PECO, BGE, Pepco, and DPL filed applications with FERC and on July 21, 2021, ACE filed an application with NJBPU for renewal of their short-term financing authority through December 31, 2023. ComEd, PECO, BGE, Pepco, DPL, and ACE expect approval of their applications by December 31, 2021.

(c) ComEd had $93 million available in new money long-term debt financing authority from the ICC as of September 30, 2021 and has an expiration date of February 1, 2023. On June 29, 2021, ComEd filed an application for $2 billion in new money long-term debt financing authority from the ICC and expects approval by December 31, 2021.

(d) PECO is currently in the process of renewing its long-term financing authority with PAPUC and expects approval by December 31, 2021.

Contractual Obligations and Off-Balance Sheet Arrangements

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 15 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd and PECO have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements in the Exelon 2020 Form 10-K for additional information.

For an in-depth discussion of the Registrants' contractual obligations and off-balance sheet arrangements, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations and Off-Balance Sheet Arrangements" in the Exelon 2020 Form 10-K and Note 6 — Accounts Receivable of the Combined Notes to Consolidated Financial Statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates, and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer, and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of Exelon's 2020 Annual Report on Form 10-K incorporated herein by reference.

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 generates and 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, fossil fuel, and other commodities.

Generation

Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards, and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2021 through 2023.

As of September 30, 2021, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 96%-99% for the remainder of 2021. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on September 30, 2021 market conditions and hedged position would be immaterial for 2021. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

Approximately 60% of Generation's uranium concentrate requirements from 2021 through 2025 are supplied by three suppliers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact in Exelon's and Generation's financial statements.

Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to commodity price risk that were described in ITEM 1A. RISK FACTORS of Exelon's 2020 Annual Report on Form 10-K. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding commodity price risk exposure.

Trading and Non-Trading Marketing Activities

The following table detailing Exelon's, Generation's, and ComEd's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2020 to September 30, 2021. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all NPNS contracts and does not segregate proprietary trading activity. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of September 30, 2021 and December 31, 2020.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2020[a]	$ 428	$ 729	$ (301)
Total change in fair value during 2021 of contracts recorded in results of operations	1,434	1,434	—
Reclassification to realized at settlement of contracts recorded in results of operations	(186)	(186)	—
Changes in fair value — recorded through regulatory assets[b]	87	—	87
Changes in allocated collateral	(2,061)	(2,061)	—
Net option premium paid	186	186	—
Option premium amortization	(45)	(45)	—
Upfront payments and amortizations[c]	(107)	(107)	—
Total mark-to-market energy contract net liabilities at September 30, 2021[a]	$ (264)	$ (50)	$ (214)

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets. As of September 30, 2021, ComEd recorded a regulatory asset of $214 million related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the nine months ended September 30, 2021, ComEd recorded $72 million of increases in fair value and an increase for realized losses due to settlements of $15 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

(c) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation, and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 14 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$ 302	$ 578	$ 63	$ 53	$ 38	$ 23	$ 1,057
Prices provided by external sources (Level 2)	17	737	40	(40)	—	—	754
Prices based on model or other valuation methods (Level 3)(c)	(566)	(1,304)	17	(15)	(18)	(189)	(2,075)
Total	$ (247)	$ 11	$ 120	$ (2)	$ 20	$ (166)	$ (264)

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.
(b) Amounts are shown net of collateral paid/(received) from counterparties (and offset against mark-to-market assets and liabilities) of $(1,645) million at September 30, 2021.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts(a)(b):							
Actively quoted prices (Level 1)	$ 302	$ 578	$ 63	$ 53	$ 38	$ 23	$ 1,057
Prices provided by external sources (Level 2)	17	737	40	(40)	—	—	754
Prices based on model or other valuation methods (Level 3)	(565)	(1,293)	39	8	5	(55)	(1,861)
Total	$ (246)	$ 22	$ 142	$ 21	$ 43	$ (32)	$ (50)

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.
(b) Amounts are shown net of collateral paid/(received) from counterparties (and offset against mark-to-market assets and liabilities) of $(1,645) million at September 30, 2021.

ComEd

	Maturities Within						
	2021	2022	2023	2024	2025	2026 and Beyond	Total Fair Value
Commodity derivative contracts(a):							
Prices based on model or other valuation methods (Level 3)(a)	$ (1)	$ (11)	$ (22)	$ (23)	$ (23)	$ (134)	$ (214)

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

Credit Risk (All Registrants)

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for detailed discussion of credit risk.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2021. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The amounts in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, and commodity exchanges, which are discussed below.

Rating as of September 30, 2021	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 701	$ 254	$ 447	—	$ —
Non-investment grade	23	2	21	—	—
No external ratings					
Internally rated — investment grade	110	1	109	—	—
Internally rated — non-investment grade	309	48	261	—	—
Total	$ 1,143	$ 305	$ 838	—	$ —

(a) As of September 30, 2021, credit collateral held from counterparties where Generation had credit exposure included $188 million of cash and $117 million of letters of credit.

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2021	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 579	$ 69	$ 53	$ 701
Non-investment grade	23	—	—	23
No external ratings				
Internally rated — investment grade	96	10	4	110
Internally rated — non-investment grade	251	49	9	309
Total	$ 949	$ 128	$ 66	$ 1,143

Net Credit Exposure by Type of Counterparty	As of September 30, 2021
Financial institutions	$ 53
Investor-owned utilities, marketers, power producers	652
Energy cooperatives and municipalities	62
Other	71
Total	$ 838

The Utility Registrants

There have been no significant changes or additions to the Utility Registrants exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2020 Annual Report on Form 10-K. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding credit exposure to suppliers.

Credit-Risk-Related Contingent Features (All Registrants)

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas, and other commodities. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 15 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's financial statements. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. To post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Note 17 — Debt and Credit Agreements of Exelon's 2020 Annual Report on Form 10-K for additional information.

Utility Registrants

As of September 30, 2021, the Utility Registrants were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Interest Rate and Foreign Exchange Risk (Exelon and Generation)

Exelon and Generation use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon and Generation may also utilize interest rate swaps to manage their interest rate exposure. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $1 million decrease in Exelon pre-tax income for the nine months ended September 30, 2021. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of September 30, 2021, Generation's NDT funds are reflected at fair value in its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 25 basis points increase in interest rates and 10% decrease in equity prices would result in a $863 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices.

ITEM 4. CONTROLS AND PROCEDURES

During the third quarter of 2021, each of the Registrants' management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing, and reporting of information in its 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 Exelon'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 September 30, 2021, 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. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. There were no changes in internal control over financial reporting during the third quarter of 2021 that materially affected, or are reasonably likely to materially affect, any of the Registrants' internal control over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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 (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2020 Form 10-K and (b) Notes 3 — Regulatory Matters and 15 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

ITEM 1A. RISK FACTORS

Risks Related to All Registrants

At September 30, 2021, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2020 Form 10-K in ITEM 1A. RISK FACTORS, except for the updates below.

We could be negatively affected by the impacts of weather (Exelon and Generation).

Our operations are affected by weather, which affects demand for electricity and natural gas, the price of energy commodities, as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, we could require greater resources to meet our contractual commitments. Extreme weather conditions or storms have affected the availability of generation and its transmission, limiting our ability to source or send power to where it is sold, and have also affected the transportation of natural gas to our generating assets and our ability to supply natural gas to our customers. In addition, drought-like conditions limiting water usage could impact our ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could cause us to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

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

Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. We estimate a reduction in Net income at Exelon and Generation of approximately $670 million to $820 million for the full year 2021 arising from these market and weather conditions. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Significant 2021 Transactions and Developments — Impacts of February 21 Extreme Weather Event and Texas-based Generating Assets Outages for additional information.

ITEM 4. MINE SAFETY DISCLOSURES

All Registrants

Not applicable to the Registrants.

ITEM 5. OTHER INFORMATION

All Registrants

None.

ITEM 6. EXHIBITS

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

Exhibit No.	Description
4.1	Supplemental Indenture, dated as of August 2, 2021, from ComEd to BNY Mellon Trust Company of Illinois, as trustee, and D.G. Donovan, as co-trustee (File No. 001-01839, Form 8-K dated August 12, 2021, Exhibit 4.1)
4.2	One Hundred and Twentieth Supplemental Indenture dated as of September 1, 2021 from PECO to U.S. Bank National Association, as trustee (File No. 000-16844, Form 8-K dated September 14, 2021, Exhibit 4.1).
10.1	Settlement Agreement, dated August 6, 2021, between Generation and EDF Inc.*
10.2	364-Day Term Loan Credit Agreement, dated August 6, 2021, between Generation and Barclays Bank PLC*
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)

*Filed herewith

Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2021 filed by the following officers for the following companies:

Exhibit No.	Description
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Joseph Nigro for Exelon Corporation
31-3	Filed by Joseph Dominguez for Exelon Generation Company, LLC
31-4	Filed by Daniel L. Eggers for Exelon Generation Company, LLC
31-5	Filed by Calvin G. Butler for Commonwealth Edison Company
31-6	Filed by Jeanne M. Jones for Commonwealth Edison Company
31-7	Filed by Michael A. Innocenzo for PECO Energy Company
31-8	Filed by Robert J. Stefani for PECO Energy Company
31-9	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Phillip S. Barnett for Pepco Holdings LLC
31-13	Filed by David M. Velazquez for Potomac Electric Power Company
31-14	Filed by Phillip S. Barnett for Potomac Electric Power Company
31-15	Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	Filed by Phillip S. Barnett for Delmarva Power & Light Company
31-17	Filed by David M. Velazquez for Atlantic City Electric Company
31-18	Filed by Phillip S. Barnett for Atlantic City Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes — Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2021 filed by the following officers for the following companies:

Exhibit No.	**Description**
32-1	Filed by Christopher M. Crane for Exelon Corporation
32-2	Filed by Joseph Nigro for Exelon Corporation
32-3	Filed by Joseph Dominguez for Exelon Generation Company, LLC
32-4	Filed by Daniel L. Eggers for Exelon Generation Company, LLC
32-5	Filed by Calvin G. Butler for Commonwealth Edison Company
32-6	Filed by Jeanne M. Jones for Commonwealth Edison Company
32-7	Filed by Michael A. Innocenzo for PECO Energy Company
32-8	Filed by Robert J. Stefani for PECO Energy Company
32-9	Filed by Carim V. Khouzami for Baltimore Gas and Electric Company
32-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
32-11	Filed by David M. Velazquez for Pepco Holdings LLC
32-12	Filed by Phillip S. Barnett for Pepco Holdings LLC
32-13	Filed by David M. Velazquez for Potomac Electric Power Company
32-14	Filed by Phillip S. Barnett for Potomac Electric Power Company
32-15	Filed by David M. Velazquez for Delmarva Power & Light Company
32-16	Filed by Phillip S. Barnett for Delmarva Power & Light Company
32-17	Filed by David M. Velazquez for Atlantic City Electric Company
32-18	Filed by Phillip S. Barnett for Atlantic City Electric Company

SIGNATURES

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

EXELON CORPORATION

/s/ CHRISTOPHER M. CRANE
Christopher M. Crane
President, Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JOSEPH NIGRO
Joseph Nigro
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ FABIAN E. SOUZA
Fabian E. Souza
Senior Vice President and Corporate Controller
(Principal Accounting Officer)

November 3, 2021

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

EXELON GENERATION COMPANY, LLC

/s/ JOSEPH DOMINGUEZ	/s/ DANIEL L. EGGERS
Joseph Dominguez Chief Executive Officer (Principal Executive Officer)	Daniel L. Eggers Chief Financial Officer (Principal Financial Officer)
/s/ MATTHEW N. BAUER	
Matthew N. Bauer Vice President and Controller (Principal Accounting Officer)	

November 3, 2021

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

COMMONWEALTH EDISON COMPANY

/s/ CALVIN G. BUTLER	/s/ JEANNE M. JONES
Calvin G. Butler	Jeanne M. Jones
Interim Chief Executive Officer (Principal Executive Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ STEVEN J. CICHOCKI	
Steven J. Cichocki	
Director, Accounting (Principal Accounting Officer)	

November 3, 2021

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

PECO ENERGY COMPANY

/s/ MICHAEL A. INNOCENZO	/s/ ROBERT J. STEFANI
Michael A. Innocenzo President and Chief Executive Officer (Principal Executive Officer)	Robert J. Stefani Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ CAROLINE FULGINITI	
Caroline Fulginiti Director, Accounting (Principal Accounting Officer)	

November 3, 2021

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

BALTIMORE GAS AND ELECTRIC COMPANY

/s/ CARIM V. KHOUZAMI	/s/ DAVID M. VAHOS
Carim V. Khouzami Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2021

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

PEPCO HOLDINGS LLC

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2021

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

POTOMAC ELECTRIC POWER COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez	Phillip S. Barnett
President and Chief Executive Officer (Principal Executive Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JULIE E. GIESE	
Julie E. Giese	
Director, Accounting (Principal Accounting Officer)	

November 3, 2021

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

DELMARVA POWER & LIGHT COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez President and Chief Executive Officer (Principal Executive Officer)	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)	

November 3, 2021

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

ATLANTIC CITY ELECTRIC COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ PHILLIP S. BARNETT
David M. Velazquez	Phillip S. Barnett
President and Chief Executive Officer (Principal Executive Officer)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ JULIE E. GIESE	
Julie E. Giese	
Director, Accounting (Principal Accounting Officer)	

November 3, 2021