EXELON Corp
Form 10-Q
November 01, 2018
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the Quarterly Period Ended September 30, 2018
or

o 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
1-16169	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
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (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
1-1910	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)	52-2297449

	701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation) 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted 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 x No o

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.

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

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. o

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

The number of shares outstanding of each registrant’s common stock as of September 30, 2018 was:

Exelon Corporation Common Stock, without par value	967,009,746
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,324
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 (formerly Pepco Holdings, Inc.)
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
Legacy PHI	PHI, 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
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc.
Constellation	Constellation Energy Group, Inc.
EEDC	Exelon Energy Delivery Company, LLC
EGR IV	ExGen Renewables IV, LLC
EGTP	ExGen Texas Power, LLC
Entergy	Entergy Nuclear FitzPatrick, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
PCI	Potomac Capital Investment Corporation and its subsidiaries
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
RPG	Renewable Power Generation
SolGen	SolGen, LLC

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.
Note "—" of the Exelon 2017 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2017 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
AGE	Albany Green Energy Project
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
BGS	Basic Generation Service
CAISO	California Independent System Operator
CAP	Customer Assistance Program
CCGTs	Combined-Cycle Gas Turbines
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	District of Columbia Public Service Commission
Default Electricity Supply	The supply of electricity by PHI's electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or Basic Generation Service
DOE	United States Department of Energy
DOEE	Department of Energy & Environment
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
EDF	Electricite de France SA and its subsidiaries

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
EE&C	Energy Efficiency and Conservation/Demand Response
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower	A Maryland demand-side management program for Pepco and DPL
EPA	United States Environmental Protection Agency
EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	Independent System Operator New England Inc.
ISO-NY	Independent System Operator New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LLRW	Low-Level Radioactive Waste
LT Plan	Long-term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
Moody’s	Moody’s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
n.m.	not meaningful
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJBPU	New Jersey Board of Public Utilities
NJDEP	New Jersey Department of Environmental Protection
NLRB	National Labor Relations Board
Non-Regulatory Agreements 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
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NUGs	Non-utility generators
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPC	Office of People’s Counsel
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PCB	Polychlorinated Biphenyl
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTEP	Regional Transmission Expansion Plan
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)
SILO	Sale-In, Lease-Out
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
TCJA	Tax Cuts and Jobs Act
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit, or Zero Emission Certificate
ZES	Zero Emission Standard

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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. 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 2017 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23, Commitments and Contingencies; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors; (b) Part 1, Financial Information, ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 17, Commitments and Contingencies; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. 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 public may read and copy any reports or other information that the Registrants file with the SEC at the SEC’s public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants’ websites at www.exeloncorp.com. Information contained on the Registrants’ websites shall not be deemed incorporated into, or to be a part of, this Report.

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PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

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

(In millions, except per share data)	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Operating revenues				
Competitive businesses revenues	$4,971	$4,455	$14,387	$12,955
Rate-regulated utility revenues	4,457	4,259	12,824	12,034
Revenues from alternative revenue programs	(25)	54	(41)	191
Total operating revenues	9,403	8,768	27,170	25,180
Operating expenses				
Competitive businesses purchased power and fuel	2,977	2,316	8,542	7,268
Rate-regulated utility purchased power and fuel	1,355	1,226	3,832	3,259
Operating and maintenance	2,346	2,275	7,036	7,658
Depreciation and amortization	1,105	1,002	3,284	2,814
Taxes other than income	469	456	1,342	1,313
Total operating expenses	8,252	7,275	24,036	22,312
(Loss) gain on sales of assets and businesses	(5)	(1)	55	4
Bargain purchase gain	—	7	—	233
Operating income	1,146	1,499	3,189	3,105
Other income and (deductions)				
Interest expense, net	(387)	(377)	(1,119)	(1,165)
Interest expense to affiliates	(6)	(9)	(19)	(29)
Other, net	194	210	212	643
Total other income and (deductions)	(199)	(176)	(926)	(551)
Income before income taxes	947	1,323	2,263	2,554
Income taxes	137	451	262	601
Equity in losses of unconsolidated affiliates	(10)	(7)	(22)	(25)
Net income	800	865	1,979	1,928
Net income attributable to noncontrolling interests	67	42	121	21
Net income attributable to common shareholders	$733	$823	$1,858	$1,907
Comprehensive income, net of income taxes				
Net income	$800	$865	$1,979	$1,928
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(17)	(14)	(50)	(42)
Actuarial loss reclassified to periodic benefit cost	62	49	186	147
Pension and non-pension postretirement benefit plan valuation adjustment	5	3	22	(55)
Unrealized gain on cash flow hedges	—	—	12	5
Unrealized gain on investments in unconsolidated affiliates	—	1	3	5
Unrealized gain (loss) on foreign currency translation	2	4	(4)	7
Unrealized gain on marketable securities	—	1	—	2
Other comprehensive income	52	44	169	69
Comprehensive income	852	909	2,148	1,997
Comprehensive income attributable to noncontrolling interests	67	42	123	19

Comprehensive income attributable to common shareholders	$785	$867	$2,025	$1,978
Average shares of common stock outstanding:				
Basic	968	962	967	941
Diluted	970	965	969	943
Earnings per average common share:				
Basic	$0.76	$0.86	$1.92	$2.03
Diluted	$0.76	$0.85	$1.92	$2.02
Dividends declared per common share	$0.35	$0.33	$1.04	$0.98

See the Combined Notes to Consolidated Financial Statements

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

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$1,979	$1,928
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	4,511	3,999
Impairment of long-lived assets and losses on regulatory assets	49	488
Gain on sales of assets and businesses	(55)	(5)
Bargain purchase gain	—	(233)
Deferred income taxes and amortization of investment tax credits	97	444
Net fair value changes related to derivatives	67	149
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(21)	(429)
Other non-cash operating activities	804	603
Changes in assets and liabilities:		
Accounts receivable	(167)	184
Inventories	(24)	(87)
Accounts payable and accrued expenses	84	(591)
Option premiums (paid) received, net	(36)	35
Collateral received (posted), net	222	(100)
Income taxes	166	167
Pension and non-pension postretirement benefit contributions	(362)	(344)
Other assets and liabilities	(639)	(535)
Net cash flows provided by operating activities	6,675	5,673
Cash flows from investing activities		
Capital expenditures	(5,497)	(5,556)
Proceeds from nuclear decommissioning trust fund sales	6,379	6,848
Investment in nuclear decommissioning trust funds	(6,553)	(7,044)
Acquisition of assets and businesses, net	(57)	(208)
Proceeds from sales of assets and businesses	90	219
Other investing activities	29	(2)
Net cash flows used in investing activities	(5,609)	(5,743)
Cash flows from financing activities		
Changes in short-term borrowings	(218)	(570)
Proceeds from short-term borrowings with maturities greater than 90 days	126	621
Repayments on short-term borrowings with maturities greater than 90 days	(1)	(610)
Issuance of long-term debt	2,664	2,616
Retirement of long-term debt	(1,480)	(1,728)
Retirement of long-term debt to financing trust	—	(250)
Sale of noncontrolling interest	—	396
Dividends paid on common stock	(999)	(921)
Common stock issued from treasury stock	—	1,150
Proceeds from employee stock plans	67	61
Other financing activities	(94)	(64)

Net cash flows provided by financing activities	65	701
Increase in cash, cash equivalents and restricted cash	1,131	631
Cash, cash equivalents and restricted cash at beginning of period	1,190	914
Cash, cash equivalents and restricted cash at end of period	$2,321	$1,545

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,918	$ 898
Restricted cash and cash equivalents	240	207
Accounts receivable, net		
Customer	4,239	4,445
Other	1,246	1,132
Mark-to-market derivative assets	696	976
Unamortized energy contract assets	42	60
Inventories, net		
Fossil fuel and emission allowances	349	340
Materials and supplies	1,316	1,311
Regulatory assets	1,340	1,267
Assets held for sale	910	—
Other	1,177	1,260
Total current assets	13,473	11,896
Property, plant and equipment, net	75,840	74,202
Deferred debits and other assets		
Regulatory assets	8,002	8,021
Nuclear decommissioning trust funds	12,464	13,272
Investments	649	640
Goodwill	6,677	6,677
Mark-to-market derivative assets	449	337
Unamortized energy contract assets	371	395
Other	1,560	1,330
Total deferred debits and other assets	30,172	30,672
Total assets[a]	$ 119,485	$ 116,770

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$834	$929
Long-term debt due within one year	771	2,088
Accounts payable	3,348	3,532
Accrued expenses	1,964	1,837
Payables to affiliates	5	5
Regulatory liabilities	689	523
Mark-to-market derivative liabilities	329	232
Unamortized energy contract liabilities	158	231
Renewable energy credit obligation	256	352
PHI merger related obligation	63	87
Liabilities held for sale	788	—
Other	935	982
Total current liabilities	10,140	10,798
Long-term debt	34,519	32,176
Long-term debt to financing trusts	390	389
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,702	11,235
Asset retirement obligations	9,747	10,029
Pension obligations	3,385	3,736
Non-pension postretirement benefit obligations	2,155	2,093
Spent nuclear fuel obligation	1,164	1,147
Regulatory liabilities	9,756	9,865
Mark-to-market derivative liabilities	482	409
Unamortized energy contract liabilities	497	609
Other	2,160	2,097
Total deferred credits and other liabilities	41,048	41,220
Total liabilities[(a)]	86,097	84,583
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 967 shares and 963 shares outstanding at September 30, 2018 and December 31, 2017, respectively)	19,063	18,964
Treasury stock, at cost (2 shares at September 30, 2018 and December 31, 2017)	(123)	(123)
Retained earnings	14,949	14,081
Accumulated other comprehensive loss, net	(2,869)	(3,026)
Total shareholders' equity	31,020	29,896
Noncontrolling interests	2,368	2,291
Total equity	33,388	32,187
Total liabilities and shareholders' equity	$119,485	$116,770

(a) Exelon's consolidated assets include $9,804 million and $9,597 million at September 30, 2018 and December 31, 2017, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,606 million and $3,618 million at September 30, 2018 and December 31, 2017, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 — Variable Interest Entities for additional information.

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

(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, 2017	965,168	$ 18,964	$ (123)	$ 14,081	$ (3,026)	$ 2,291	$ 32,187
Net income	—	—	—	1,858	—	121	1,979
Long-term incentive plan activity	2,677	32	—	—	—	—	32
Employee stock purchase plan issuances	997	67	—	—	—	—	67
Changes in equity of noncontrolling interests	—	—	—	—	—	(46)	(46)
Common stock dividends	—	—	—	(1,004)	—	—	(1,004)
Other comprehensive income, net of income taxes	—	—	—	—	167	2	169
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	—	—	14	(10)	—	4
Balance, September 30, 2018	968,842	$ 19,063	$ (123)	$ 14,949	$ (2,869)	$ 2,368	$ 33,388

See the Combined Notes to Consolidated Financial Statements

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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)	2018	2017	2018	2017
Operating revenues				
Operating revenues	$4,970	$4,454	$14,389	$12,949
Operating revenues from affiliates	308	296	979	894
Total operating revenues	5,278	4,750	15,368	13,843
Operating expenses				
Purchased power and fuel	2,977	2,315	8,542	7,267
Purchased power and fuel from affiliates	3	16	10	19
Operating and maintenance	1,218	1,205	3,643	4,343
Operating and maintenance from affiliates	152	171	483	536
Depreciation and amortization	468	410	1,383	1,046
Taxes other than income	143	141	414	425
Total operating expenses	4,961	4,258	14,475	13,636
(Loss) gain on sales of assets and businesses	(6)	(2)	48	3
Bargain purchase gain	—	7	—	233
Operating income	311	497	941	443
Other income and (deductions)				
Interest expense, net	(93)	(103)	(278)	(313)
Interest expense to affiliates	(8)	(10)	(27)	(29)
Other, net	179	209	164	648
Total other income and (deductions)	78	96	(141)	306
Income before income taxes	389	593	800	749
Income taxes	78	239	110	215
Equity in losses of unconsolidated affiliates	(11)	(8)	(23)	(26)
Net income	300	346	667	508
Net income attributable to noncontrolling interests	66	42	120	21
Net income attributable to membership interest	$234	$304	$547	$487
Comprehensive income, net of income taxes				
Net income	$300	$346	$667	$508
Other comprehensive income (loss), net of income taxes				
Unrealized gain on cash flow hedges	—	—	12	5
Unrealized gain on investments in unconsolidated affiliates	—	—	3	4
Unrealized gain (loss) on foreign currency translation	2	4	(4)	7
Other comprehensive income	2	4	11	16
Comprehensive income	302	350	678	524
Comprehensive income attributable to noncontrolling interests	66	42	122	19
Comprehensive income attributable to membership interest	$236	$308	$556	$505

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

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$667	$508
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	2,608	2,231
Impairment of long-lived assets	49	485
Gain on sales of assets and businesses	(48)	(3)
Bargain purchase gain	—	(233)
Deferred income taxes and amortization of investment tax credits	(278)	(179)
Net fair value changes related to derivatives	73	160
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(21)	(429)
Other non-cash operating activities	187	132
Changes in assets and liabilities:		
Accounts receivable	126	66
Receivables from and payables to affiliates, net	(7)	27
Inventories	(10)	(43)
Accounts payable and accrued expenses	(59)	(255)
Option premiums (paid) received, net	(36)	35
Collateral received (posted), net	228	(77)
Income taxes	220	154
Pension and non-pension postretirement benefit contributions	(134)	(122)
Other assets and liabilities	(154)	(187)
Net cash flows provided by operating activities	3,411	2,270
Cash flows from investing activities		
Capital expenditures	(1,660)	(1,654)
Proceeds from nuclear decommissioning trust fund sales	6,379	6,848
Investment in nuclear decommissioning trust funds	(6,553)	(7,044)
Acquisition of assets and businesses, net	(57)	(208)
Proceeds from sales of assets and businesses	90	218
Other investing activities	(5)	(35)
Net cash flows used in investing activities	(1,806)	(1,875)
Cash flows from financing activities		
Changes in short-term borrowings	—	(620)
Proceeds from short-term borrowings with maturities greater than 90 days	1	121
Repayments of short-term borrowings with maturities greater than 90 days	(1)	(110)
Issuance of long-term debt	14	789
Retirement of long-term debt	(100)	(541)
Changes in Exelon intercompany money pool	(54)	91
Distributions to member	(688)	(494)
Contributions from member	54	102
Sale of noncontrolling interest	—	396
Other financing activities	(46)	(31)

Net cash flows used in financing activities	(820)	(297)
Increase in cash, cash equivalents and restricted cash	785	98
Cash, cash equivalents and restricted cash at beginning of period	554	448
Cash, cash equivalents and restricted cash at end of period	$1,339	$546

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

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,187	$ 416
Restricted cash and cash equivalents	152	138
Accounts receivable, net		
Customer	2,545	2,697
Other	278	321
Mark-to-market derivative assets	696	976
Receivables from affiliates	182	140
Unamortized energy contract assets	42	60
Inventories, net		
Fossil fuel and emission allowances	255	264
Materials and supplies	948	937
Assets held for sale	910	—
Other	854	933
Total current assets	8,049	6,882
Property, plant and equipment, net	24,168	24,906
Deferred debits and other assets		
Nuclear decommissioning trust funds	12,464	13,272
Investments	433	433
Goodwill	47	47
Mark-to-market derivative assets	449	334
Prepaid pension asset	1,472	1,502
Unamortized energy contract assets	370	395
Deferred income taxes	25	16
Other	730	670
Total deferred debits and other assets	15,990	16,669
Total assets[(a)]	$ 48,207	$ 48,457

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

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$—	$2
Long-term debt due within one year	336	346
Accounts payable	1,450	1,773
Accrued expenses	1,200	1,022
Payables to affiliates	144	123
Borrowings from Exelon intercompany money pool	—	54
Mark-to-market derivative liabilities	305	211
Unamortized energy contract liabilities	33	43
Renewable energy credit obligation	256	352
Liabilities held for sale	788	—
Other	255	265
Total current liabilities	4,767	4,191
Long-term debt	7,605	7,734
Long-term debt to affiliate	901	910
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,532	3,811
Asset retirement obligations	9,521	9,844
Non-pension postretirement benefit obligations	903	916
Spent nuclear fuel obligation	1,164	1,147
Payables to affiliates	2,959	3,065
Mark-to-market derivative liabilities	237	174
Unamortized energy contract liabilities	23	48
Other	635	658
Total deferred credits and other liabilities	18,974	19,663
Total liabilities[(a)]	32,247	32,498
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,411	9,357
Undistributed earnings	4,214	4,349
Accumulated other comprehensive loss, net	(31)	(37)
Total member's equity	13,594	13,669
Noncontrolling interests	2,366	2,290
Total equity	15,960	15,959
Total liabilities and equity	$48,207	$48,457

(a) Generation's consolidated assets include $9,768 million and $9,556 million at September 30, 2018 and December 31, 2017, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,528 million and $3,516 million at September 30, 2018 and December 31, 2017, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 — Variable Interest Entities for additional information.

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

(In millions)	Member's Equity				
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2017	$9,357	$ 4,349	$ (37)	$ 2,290	$15,959
Net income	—	547	—	120	667
Changes in equity of noncontrolling interests	—	—	—	(46)	(46)
Contribution from member	54	—	—	—	54
Distributions to member	—	(688)	—	—	(688)
Other comprehensive income, net of income taxes	—	—	9	2	11
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, September 30, 2018	$9,411	$ 4,214	$ (31)	$ 2,366	$15,960

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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)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$1,609	$1,552	$4,512	$4,167
Revenues from alternative revenue programs	(15)	16	(27)	48
Operating revenues from affiliates	4	3	23	12
Total operating revenues	1,598	1,571	4,508	4,227
Operating expenses				
Purchased power	496	489	1,281	1,178
Purchased power from affiliate	123	40	421	63
Operating and maintenance	276	277	785	897
Operating and maintenance from affiliate	61	69	189	199
Depreciation and amortization	237	212	696	631
Taxes other than income	82	80	238	223
Total operating expenses	1,275	1,167	3,610	3,191
Gain on sales of assets	—	—	5	—
Operating income	323	404	903	1,036
Other income and (deductions)				
Interest expense, net	(82)	(86)	(251)	(265)
Interest expense to affiliates	(3)	(3)	(10)	(10)
Other, net	7	5	21	14
Total other income and (deductions)	(78)	(84)	(240)	(261)
Income before income taxes	245	320	663	775
Income taxes	52	131	140	328
Net income	$193	$189	$523	$447
Comprehensive income	$193	$189	$523	$447

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

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$523	$447
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	696	631
Deferred income taxes and amortization of investment tax credits	214	455
Other non-cash operating activities	187	112
Changes in assets and liabilities:		
Accounts receivable	(190)	31
Receivables from and payables to affiliates, net	8	346
Inventories	4	6
Accounts payable and accrued expenses	(38)	(706)
Collateral posted, net	(10)	(22)
Income taxes	(65)	(205)
Pension and non-pension postretirement benefit contributions	(41)	(38)
Other assets and liabilities	(170)	63
Net cash flows provided by operating activities	1,118	1,120
Cash flows from investing activities		
Capital expenditures	(1,540)	(1,698)
Other investing activities	22	17
Net cash flows used in investing activities	(1,518)	(1,681)
Cash flows from financing activities		
Issuance of long-term debt	1,350	1,000
Retirement of long-term debt	(840)	(425)
Contributions from parent	387	567
Dividends paid on common stock	(345)	(316)
Other financing activities	(16)	(14)
Net cash flows provided by financing activities	536	812
Increase in cash, cash equivalents and restricted cash	136	251
Cash, cash equivalents and restricted cash at beginning of period	144	58
Cash, cash equivalents and restricted cash at end of period	$280	$309

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

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 124	$ 76
Restricted cash	12	5
Accounts receivable, net		
Customer	590	559
Other	450	266
Receivables from affiliates	13	13
Inventories, net	146	152
Regulatory assets	256	225
Other	94	68
Total current assets	1,685	1,364
Property, plant and equipment, net	21,642	20,723
Deferred debits and other assets		
Regulatory assets	1,229	1,054
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,469	2,528
Prepaid pension asset	1,083	1,188
Other	380	238
Total deferred debits and other assets	7,792	7,639
Total assets	$ 31,119	$ 29,726

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

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Long-term debt due within one year	$ 300	$ 840
Accounts payable	576	568
Accrued expenses	253	327
Payables to affiliates	82	74
Customer deposits	111	112
Regulatory liabilities	320	249
Mark-to-market derivative liability	24	21
Other	90	103
Total current liabilities	1,756	2,294
Long-term debt	7,800	6,761
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,744	3,469
Asset retirement obligations	115	111
Non-pension postretirement benefits obligations	206	219
Regulatory liabilities	6,318	6,328
Mark-to-market derivative liability	235	235
Other	633	562
Total deferred credits and other liabilities	11,251	10,924
Total liabilities	21,012	20,184
Commitments and contingencies		
Shareholders’ equity		
Common stock	1,588	1,588
Other paid-in capital	7,209	6,822
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,949	2,771
Total shareholders’ equity	10,107	9,542
Total liabilities and shareholders’ equity	$ 31,119	$ 29,726

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

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders' Equity
Balance, December 31, 2017	$ 1,588	$ 6,822	$ (1,639)	$ 2,771	$ 9,542
Net income	—	—	523	—	523
Appropriation of retained earnings for future dividends	—	—	(523)	523	—
Common stock dividends	—	—	—	(345)	(345)
Contributions from parent	—	387	—	—	387
Balance, September 30, 2018	$ 1,588	$ 7,209	$ (1,639)	$ 2,949	$ 10,107

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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)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$697	$660	$1,886	$1,798
Natural gas operating revenues	57	53	382	338
Revenues from alternative revenue programs	1	—	2	—
Operating revenues from affiliates	2	2	5	5
Total operating revenues	757	715	2,275	2,141
Operating expenses				
Purchased power	215	190	576	483
Purchased fuel	14	14	148	126
Purchased power from affiliate	34	31	94	110
Operating and maintenance	184	161	572	488
Operating and maintenance from affiliates	35	36	114	107
Depreciation and amortization	75	72	224	213
Taxes other than income	46	42	125	116
Total operating expenses	603	546	1,853	1,643
Gain on sales of assets	—	—	1	—
Operating income	154	169	423	498
Other income and (deductions)				
Interest expense, net	(28)	(28)	(85)	(84)
Interest expense to affiliates	(4)	(3)	(11)	(9)
Other, net	2	2	4	6
Total other income and (deductions)	(30)	(29)	(92)	(87)
Income before income taxes	124	140	331	411
Income taxes	(2)	28	(5)	84
Net income	$126	$112	$336	$327
Comprehensive income	$126	$112	$336	$327

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

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$336	$327
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	224	213
Gain on sales of assets	(1)	—
Deferred income taxes and amortization of investment tax credits	5	37
Other non-cash operating activities	41	38
Changes in assets and liabilities:		
Accounts receivable	(85)	45
Receivables from and payables to affiliates, net	1	(10)
Inventories	(13)	(5)
Accounts payable and accrued expenses	(1)	(41)
Income taxes	(16)	51
Pension and non-pension postretirement benefit contributions	(25)	(23)
Other assets and liabilities	26	(29)
Net cash flows provided by operating activities	492	603
Cash flows from investing activities		
Capital expenditures	(615)	(537)
Changes in Exelon intercompany money pool	—	74
Other investing activities	6	6
Net cash flows used in investing activities	(609)	(457)
Cash flows from financing activities		
Issuance of long-term debt	700	325
Retirement of long-term debt	(500)	—
Contributions from parent	71	16
Dividends paid on common stock	(300)	(216)
Other financing activities	(22)	(4)
Net cash flows (used in) provided by financing activities	(51)	121
(Decrease) increase in cash, cash equivalents and restricted cash	(168)	267
Cash, cash equivalents and restricted cash at beginning of period	275	67
Cash, cash equivalents and restricted cash at end of period	$107	$334

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

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 102	$ 271
Restricted cash and cash equivalents	5	4
Accounts receivable, net		
Customer	307	327
Other	190	105
Inventories, net		
Fossil fuel	39	31
Materials and supplies	35	30
Prepaid utility taxes	32	8
Regulatory assets	84	29
Other	19	17
Total current assets	813	822
Property, plant and equipment, net	8,461	8,053
Deferred debits and other assets		
Regulatory assets	448	381
Investments	26	25
Receivable from affiliates	489	537
Prepaid pension asset	350	340
Other	34	12
Total deferred debits and other assets	1,347	1,295
Total assets	$ 10,621	$ 10,170

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

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$ —	$ 500
Accounts payable	387	370
Accrued expenses	89	114
Payables to affiliates	53	53
Customer deposits	67	66
Regulatory liabilities	159	141
Other	31	23
Total current liabilities	786	1,267
Long-term debt	3,083	2,403
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,909	1,789
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	288
Regulatory liabilities	581	549
Other	79	86
Total deferred credits and other liabilities	2,884	2,739
Total liabilities	6,937	6,593
Commitments and contingencies		
Shareholder’s equity		
Common stock	2,560	2,489
Retained earnings	1,124	1,087
Accumulated other comprehensive income, net	—	1
Total shareholder’s equity	3,684	3,577
Total liabilities and shareholder's equity	$ 10,621	$ 10,170

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

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder's Equity
Balance, December 31, 2017	$ 2,489	$ 1,087	$ 1	$ 3,577
Net income	—	336	—	336
Common stock dividends	—	(300)	—	(300)
Contributions from parent	71	—	—	71
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	1	(1)	—
Balance, September 30, 2018	$ 2,560	$ 1,124	$ —	$ 3,684

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$652	$626	$1,847	$1,811
Natural gas operating revenues	79	73	527	438
Revenues from alternative revenue programs	(6)	36	(23)	102
Operating revenues from affiliates	6	3	18	12
Total operating revenues	731	738	2,369	2,363
Operating expenses				
Purchased power	183	159	510	407
Purchased fuel	21	13	176	118
Purchased power from affiliate	68	97	195	328
Operating and maintenance	144	138	462	421
Operating and maintenance from affiliates	38	37	116	111
Depreciation and amortization	110	109	358	348
Taxes other than income	64	61	188	180
Total operating expenses	628	614	2,005	1,913
Gain on sales of assets	—	—	1	—
Operating income	103	124	365	450
Other income and (deductions)				
Interest expense, net	(27)	(24)	(78)	(69)
Interest expense to affiliates	—	(2)	—	(11)
Other, net	5	4	14	12
Total other income and (deductions)	(22)	(22)	(64)	(68)
Income before income taxes	81	102	301	382
Income taxes	18	40	59	151
Net income	$63	$62	$242	$231
Comprehensive income	$63	$62	$242	$231

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

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$242	$231
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	358	348
Deferred income taxes and amortization of investment tax credits	82	141
Other non-cash operating activities	42	52
Changes in assets and liabilities:		
Accounts receivable	72	95
Receivables from and payables to affiliates, net	(4)	(13)
Inventories	(8)	(18)
Accounts payable and accrued expenses	(3)	(25)
Collateral received, net	1	—
Income taxes	(48)	12
Pension and non-pension postretirement benefit contributions	(50)	(50)
Other assets and liabilities	(9)	(72)
Net cash flows provided by operating activities	675	701
Cash flows from investing activities		
Capital expenditures	(667)	(615)
Other investing activities	8	6
Net cash flows used in investing activities	(659)	(609)
Cash flows from financing activities		
Changes in short-term borrowings	(77)	(45)
Issuance of long-term debt	300	300
Retirement of long-term debt	—	(41)
Retirement of long-term debt to financing trust	—	(250)
Dividends paid on common stock	(157)	(148)
Contributions from parent	18	77
Other financing activities	(2)	(5)
Net cash flows provided by (used in) financing activities	82	(112)
Increase (decrease) in cash, cash equivalents and restricted cash	98	(20)
Cash, cash equivalents and restricted cash at beginning of period	18	50
Cash, cash equivalents and restricted cash at end of period	$116	$30

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 113	$ 17
Restricted cash and cash equivalents	3	1
Accounts receivable, net		
Customer	296	375
Other	96	94
Receivables from affiliates	—	1
Inventories, net		
Gas held in storage	46	37
Materials and supplies	39	40
Prepaid utility taxes	—	69
Regulatory assets	195	174
Other	10	3
Total current assets	798	811
Property, plant and equipment, net	8,039	7,602
Deferred debits and other assets		
Regulatory assets	402	397
Investments	5	5
Prepaid pension asset	290	285
Other	7	4
Total deferred debits and other assets	704	691
Total assets	$ 9,541	$ 9,104

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 77
Accounts payable	277	265
Accrued expenses	146	164
Payables to affiliates	47	52
Customer deposits	119	116
Regulatory liabilities	95	62
Other	23	24
Total current liabilities	707	760
Long-term debt	2,876	2,577
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,345	1,244
Asset retirement obligations	24	23
Non-pension postretirement benefits obligations	200	202
Regulatory liabilities	1,070	1,101
Other	75	56
Total deferred credits and other liabilities	2,714	2,626
Total liabilities	6,297	5,963
Commitments and contingencies		
Shareholders’ equity		
Common stock	1,623	1,605
Retained earnings	1,621	1,536
Total shareholders' equity	3,244	3,141
Total liabilities and shareholders’ equity	$ 9,541	$ 9,104

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders' Equity
Balance, December 31, 2017	$ 1,605	$ 1,536	$ 3,141
Net income	—	242	242
Common stock dividends	—	(157)	(157)
Contributions from parent	18	—	18
Balance, September 30, 2018	$ 1,623	$ 1,621	$ 3,244

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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)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$1,340	$1,278	$3,541	$3,376
Natural gas operating revenues	23	18	129	105
Revenues from alternative revenue programs	(5)	2	7	41
Operating revenues from affiliates	3	12	11	35
Total operating revenues	1,361	1,310	3,688	3,557
Operating expenses				
Purchased power	415	354	1,077	901
Purchased fuel	12	7	65	46
Purchased power and fuel from affiliates	82	112	268	371
Operating and maintenance	261	214	751	666
Operating and maintenance from affiliates	31	37	106	108
Depreciation, amortization and accretion	192	179	555	511
Taxes other than income	123	122	343	344
Total operating expenses	1,116	1,025	3,165	2,947
Gain on sales of assets	—	—	—	1
Operating income	245	285	523	611
Other income and (deductions)				
Interest expense, net	(65)	(62)	(193)	(183)
Other, net	11	13	33	40
Total other income and (deductions)	(54)	(49)	(160)	(143)
Income before income taxes	191	236	363	468
Income taxes	4	83	28	109
Equity in earnings of unconsolidated affiliate	—	—	1	—
Net income	$187	$153	$336	$359
Comprehensive income	$187	$153	$336	$359

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

(In millions)	Nine Months Ended September 30, 2018	2017
Cash flows from operating activities		
Net income	$336	$359
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	555	511
Deferred income taxes and amortization of investment tax credits	50	190
Other non-cash operating activities	109	66
Changes in assets and liabilities:		
Accounts receivable	(89)	(42)
Receivables from and payables to affiliates, net	10	(13)
Inventories	—	(29)
Accounts payable and accrued expenses	115	(49)
Income taxes	(31)	82
Pension and non-pension postretirement benefit contributions	(66)	(74)
Other assets and liabilities	(144)	(206)
Net cash flows provided by operating activities	845	795
Cash flows from investing activities		
Capital expenditures	(988)	(995)
Proceeds from sales of long-lived assets	—	1
Other investing activities	2	4
Net cash flows used in investing activities	(986)	(990)
Cash flows from financing activities		
Changes in short-term borrowings	(141)	96
Proceeds from short-term borrowings with maturities greater than 90 days	125	—
Repayments of short-term borrowings with maturities greater than 90 days	—	(500)
Issuance of long-term debt	300	202
Retirement of long-term debt	(33)	(127)
Distributions to member	(232)	(267)
Contributions from parent	237	758
Change in Exelon intercompany money pool	10	1
Other financing activities	(6)	(2)
Net cash flows provided by financing activities	260	161
Increase (decrease) in cash, cash equivalents and restricted cash	119	(34)
Cash, cash equivalents and restricted cash at beginning of period	95	236
Cash, cash equivalents and restricted cash at end of period	$214	$202

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

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 153	$ 30
Restricted cash and cash equivalents	42	42
Accounts receivable, net		
Customer	500	486
Other	266	206
Inventories, net		
Gas held in storage	9	7
Materials and supplies	149	151
Regulatory assets	521	554
Other	60	75
Total current assets	1,700	1,551
Property, plant and equipment, net	13,167	12,498
Deferred debits and other assets		
Regulatory assets	2,374	2,493
Investments	133	132
Goodwill	4,005	4,005
Long-term note receivable	—	4
Prepaid pension asset	499	490
Deferred income taxes	12	4
Other	67	70
Total deferred debits and other assets	7,090	7,198
Total assets[(a)]	$ 21,957	$ 21,247

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

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 334	$ 350
Long-term debt due within one year	117	396
Accounts payable	505	348
Accrued expenses	269	261
Payables to affiliates	102	90
Borrowings from Exelon intercompany money pool	10	—
Unamortized energy contract liabilities	125	188
Customer deposits	113	119
Merger related obligation	38	42
Regulatory liabilities	99	56
Other	57	81
Total current liabilities	1,769	1,931
Long-term debt	5,972	5,478
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,243	2,070
Asset retirement obligations	53	16
Non-pension postretirement benefit obligations	102	105
Regulatory liabilities	1,783	1,872
Unamortized energy contract liabilities	474	561
Other	395	389
Total deferred credits and other liabilities	5,050	5,013
Total liabilities[a]	12,791	12,422
Commitments and contingencies		
Member's equity		
Membership interest	9,072	8,835
Undistributed earnings (losses)	94	(10)
Total member's equity	9,166	8,825
Total liabilities and member's equity	$ 21,957	$ 21,247

(a) PHI’s consolidated total assets include $36 million and $41 million at September 30, 2018 and December 31, 2017, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI’s consolidated total liabilities include $78 million and $102 million at September 30, 2018 and December 31, 2017, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 3 — Variable Interest Entities for additional information.

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

(In millions)	Membership Interest	Undistributed Earnings (Losses)	Member's Equity
Balance, December 31, 2017	$ 8,835	$ (10)	$ 8,825
Net income	—	336	336
Distributions to member	—	(232)	(232)
Contributions from parent	237	—	237
Balance, September 30, 2018	$ 9,072	$ 94	$ 9,166

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$630	$600	$1,697	$1,622
Revenues from alternative revenue programs	(4)	3	6	23
Operating revenues from affiliates	2	1	5	4
Total operating revenues	628	604	1,708	1,649
Operating expenses				
Purchased power	131	111	354	268
Purchased power from affiliates	46	57	143	210
Operating and maintenance	84	89	216	296
Operating and maintenance from affiliates	52	14	167	40
Depreciation and amortization	99	82	286	242
Taxes other than income	104	102	288	282
Total operating expenses	516	455	1,454	1,338
Gain on sales of assets	—	—	—	1
Operating income	112	149	254	312
Other income and (deductions)				
Interest expense, net	(32)	(31)	(96)	(89)
Other, net	7	7	23	22
Total other income and (deductions)	(25)	(24)	(73)	(67)
Income before income taxes	87	125	181	245
Income taxes	(2)	38	7	57
Net income	$89	$87	$174	$188
Comprehensive income	$89	$87	$174	$188

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POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$174	$188
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	286	242
Deferred income taxes and amortization of investment tax credits	(5)	90
Other non-cash operating activities	42	8
Changes in assets and liabilities:		
Accounts receivable	(36)	(43)
Receivables from and payables to affiliates, net	(9)	(10)
Inventories	6	(15)
Accounts payable and accrued expenses	104	(24)
Income taxes	(18)	80
Pension and non-pension postretirement benefit contributions	(11)	(69)
Other assets and liabilities	(137)	(99)
Net cash flows provided by operating activities	396	348
Cash flows from investing activities		
Capital expenditures	(475)	(439)
Proceeds from sales of long-lived assets	—	1
Other investing activities	3	—
Net cash flows used in investing activities	(472)	(438)
Cash flows from financing activities		
Changes in short-term borrowings	38	(23)
Issuance of long-term debt	100	202
Retirement of long-term debt	(8)	(7)
Dividends paid on common stock	(128)	(133)
Contributions from parent	85	161
Other financing activities	(4)	(1)
Net cash flows provided by financing activities	83	199
Increase in cash, cash equivalents and restricted cash	7	109
Cash, cash equivalents and restricted cash at beginning of period	40	42
Cash, cash equivalents and restricted cash at end of period	$47	$151

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POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 12	$ 5
Restricted cash and cash equivalents	35	35
Accounts receivable, net		
Customer	235	250
Other	102	87
Inventories, net	81	87
Regulatory assets	284	213
Other	9	33
Total current assets	758	710
Property, plant and equipment, net	6,337	6,001
Deferred debits and other assets		
Regulatory assets	662	678
Investments	105	102
Prepaid pension asset	318	322
Other	19	19
Total deferred debits and other assets	1,104	1,121
Total assets	$ 8,199	$ 7,832

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POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 64	$ 26
Long-term debt due within one year	14	19
Accounts payable	234	139
Accrued expenses	141	137
Payables to affiliates	70	74
Customer deposits	53	54
Regulatory liabilities	5	3
Merger related obligation	38	42
Current portion of DC PLUG obligation	30	28
Other	9	28
Total current liabilities	658	550
Long-term debt	2,611	2,521
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,139	1,063
Non-pension postretirement benefit obligations	31	36
Regulatory liabilities	759	829
Other	337	300
Total deferred credits and other liabilities	2,266	2,228
Total liabilities	5,535	5,299
Commitments and contingencies		
Shareholder's equity		
Common stock	1,555	1,470
Retained earnings	1,109	1,063
Total shareholder's equity	2,664	2,533
Total liabilities and shareholder's equity	$ 8,199	$ 7,832

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 1,470	$ 1,063	$ 2,533
Net income	—	174	174
Common stock dividends	—	(128)	(128)
Contributions from parent	85	—	85
Balance, September 30, 2018	$ 1,555	$ 1,109	$ 2,664

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$302	$308	$861	$851
Natural gas operating revenues	24	18	129	105
Revenues from alternative revenue programs	—	(1)	5	9
Operating revenues from affiliates	2	2	6	6
Total operating revenues	328	327	1,001	971
Operating expenses				
Purchased power	96	75	258	215
Purchased fuel	11	7	64	46
Purchased power from affiliate	26	47	103	138
Operating and maintenance	44	71	137	204
Operating and maintenance from affiliates	38	8	119	23
Depreciation and amortization	47	45	135	124
Taxes other than income	15	15	43	43
Total operating expenses	277	268	859	793
Operating income	51	59	142	178
Other income and (deductions)				
Interest expense, net	(15)	(13)	(42)	(38)
Other, net	2	4	7	10
Total other income and (deductions)	(13)	(9)	(35)	(28)
Income before income taxes	38	50	107	150
Income taxes	5	19	17	43
Net income	$33	$31	$90	$107
Comprehensive income	$33	$31	$90	$107

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

(In millions)	Nine Months Ended September 30, 2018	2017
Cash flows from operating activities		
Net income	$90	$107
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	135	124
Deferred income taxes and amortization of investment tax credits	24	61
Other non-cash operating activities	16	6
Changes in assets and liabilities:		
Accounts receivable	13	7
Receivables from and payables to affiliates, net	(14)	—
Inventories	(3)	(6)
Accounts payable and accrued expenses	18	—
Income taxes	—	33
Other assets and liabilities	13	(40)
Net cash flows provided by operating activities	292	292
Cash flows from investing activities		
Capital expenditures	(254)	(294)
Other investing activities	1	1
Net cash flows used in investing activities	(253)	(293)
Cash flows from financing activities		
Changes in short-term borrowings	(216)	54
Issuance of long-term debt	200	—
Retirement of long-term debt	(4)	(14)
Dividends paid on common stock	(58)	(82)
Contributions from parent	150	—
Other financing activities	(3)	—
Net cash flows provided by (used in) financing activities	69	(42)
Increase (decrease) in cash, cash equivalents and restricted cash	108	(43)
Cash, cash equivalents and restricted cash at beginning of period	2	46
Cash, cash equivalents and restricted cash at end of period	$110	$3

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 110	$ 2
Accounts receivable, net		
Customer	121	146
Other	53	38
Inventories, net		
Gas held in storage	9	7
Materials and supplies	37	36
Regulatory assets	66	69
Other	18	27
Total current assets	414	325
Property, plant and equipment, net	3,748	3,579
Deferred debits and other assets		
Regulatory assets	235	245
Goodwill	8	8
Prepaid pension asset	188	193
Other	8	7
Total deferred debits and other assets	439	453
Total assets	$ 4,601	$ 4,357

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 216
Long-term debt due within one year	79	83
Accounts payable	104	82
Accrued expenses	52	35
Payables to affiliates	30	46
Customer deposits	35	35
Regulatory liabilities	67	42
Other	6	8
Total current liabilities	373	547
Long-term debt	1,415	1,217
Deferred credits and other liabilities		
Regulatory liabilities	587	593
Deferred income taxes and unamortized investment tax credits	645	603
Non-pension postretirement benefit obligations	15	14
Other	49	48
Total deferred credits and other liabilities	1,296	1,258
Total liabilities	3,084	3,022
Commitments and contingencies		
Shareholder's equity		
Common stock	914	764
Retained earnings	603	571
Total shareholder's equity	1,517	1,335
Total liabilities and shareholder's equity	$ 4,601	$ 4,357

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 764	$ 571	$ 1,335
Net income	—	90	90
Common stock dividends	—	(58)	(58)
Contributions from parent	150	—	150
Balance, September 30, 2018	$ 914	$ 603	$ 1,517

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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)	2018	2017	2018	2017
Operating revenues				
Electric operating revenues	$406	$370	$983	$904
Revenues from alternative revenue programs	(1)	—	(4)	9
Operating revenues from affiliates	1	—	2	2
Total operating revenues	406	370	981	915
Operating expenses				
Purchased power	188	169	465	418
Purchased power from affiliates	10	7	21	24
Operating and maintenance	52	66	146	205
Operating and maintenance from affiliates	33	6	104	20
Depreciation and amortization	38	41	107	113
Taxes other than income	1	2	4	6
Total operating expenses	322	291	847	786
Operating income	84	79	134	129
Other income and (deductions)				
Interest expense, net	(16)	(15)	(48)	(46)
Other, net	1	1	2	6
Total other income and (deductions)	(15)	(14)	(46)	(40)
Income before income taxes	69	65	88	89
Income taxes	8	24	12	12
Net income	$61	$41	$76	$77
Comprehensive income	$61	$41	$76	$77

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

	Nine Months Ended September 30,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$76	$77
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	107	113
Deferred income taxes and amortization of investment tax credits	24	28
Other non-cash operating activities	24	21
Changes in assets and liabilities:		
Accounts receivable	(66)	(7)
Receivables from and payables to affiliates, net	(3)	(5)
Inventories	(2)	(7)
Accounts payable and accrued expenses	21	9
Income taxes	(3)	(9)
Pension and non-pension postretirement benefit contributions	(6)	—
Other assets and liabilities	(12)	(62)
Net cash flows provided by operating activities	160	158
Cash flows from investing activities		
Capital expenditures	(247)	(242)
Other investing activities	(1)	—
Net cash flows used in investing activities	(248)	(242)
Cash flows from financing activities		
Changes in short-term borrowings	37	65
Proceeds from short-term borrowings with maturities greater than 90 days	125	—
Retirement of long-term debt	(22)	(25)
Dividends paid on common stock	(46)	(53)
Net cash flows provided by (used in) financing activities	94	(13)
Increase (decrease) in cash, cash equivalents and restricted cash	6	(97)
Cash, cash equivalents and restricted cash at beginning of period	31	133
Cash, cash equivalents and restricted cash at end of period	$37	$36

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

(In millions)	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 11	$ 2
Restricted cash and cash equivalents	7	6
Accounts receivable, net		
Customer	144	92
Other	59	56
Inventories, net	31	29
Regulatory assets	44	71
Other	21	2
Total current assets	317	258
Property, plant and equipment, net	2,883	2,706
Deferred debits and other assets		
Regulatory assets	383	359
Long-term note receivable	—	4
Prepaid pension asset	70	73
Other	41	45
Total deferred debits and other assets	494	481
Total assets[(a)]	$ 3,694	$ 3,445

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

(In millions)	September 30, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 270	$ 108
Long-term debt due within one year	22	281
Accounts payable	149	118
Accrued expenses	38	33
Payables to affiliates	25	29
Customer deposits	26	31
Regulatory liabilities	27	11
Other	9	8
Total current liabilities	566	619
Long-term debt	1,078	840
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	534	493
Non-pension postretirement benefit obligations	16	14
Regulatory liabilities	401	411
Other	26	25
Total deferred credits and other liabilities	977	943
Total liabilities[(a)]	2,621	2,402
Commitments and contingencies		
Shareholder's equity		
Common stock	912	912
Retained earnings	161	131
Total shareholder's equity	1,073	1,043
Total liabilities and shareholder's equity	$ 3,694	$ 3,445

(a) ACE’s consolidated total assets include $26 million and $29 million at September 30, 2018 and December 31, 2017, respectively, of ACE's consolidated VIE that can only be used to settle the liabilities of the VIE. ACE’s consolidated total liabilities include $68 million and $90 million at September 30, 2018 and December 31, 2017, respectively, of ACE's consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 — Variable Interest Entities for additional information.

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2017	$ 912	$ 131	$ 1,043
Net income	—	76	76
Common stock dividends	—	(46)	(46)
Balance, September 30, 2018	$ 912	$ 161	$ 1,073

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

Index to Combined Notes To Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the Registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
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	•	•	•		•	•			•	•	•	•		•			•	•	•
Atlantic City Electric Company	•	•	•		•	•			•	•	•	•		•			•	•	•

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

1. Significant Accounting Policies (All Registrants)
Description of Business (All Registrants)
Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses.

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.	Six reportable segments: Mid-Atlantic, Midwest, New England, 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)
	Purchase and regulated retail sale of electricity	

Atlantic City Electric Company	Transmission and distribution of electricity to retail customers	Portions of Southern New Jersey

Basis of Presentation (All Registrants)

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

The accompanying consolidated financial statements as of September 30, 2018 and 2017 and for the three and nine months then ended 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, 2017 revised 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, 2018. 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.

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Prior Period Adjustments and Reclassifications (All Registrants)

Certain prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018.

Beginning on January 1, 2018, Exelon adopted the following new accounting standards requiring reclassification or adjustments to previously reported information as follows:

- Statement of Cash Flows: Classification of Restricted Cash. The Registrants applied the new guidance using the full retrospective method and, accordingly, have recasted the presentation of restricted cash in their Consolidated Statements of Cash Flows in the prior periods presented. See Note 18 — Supplemental Financial Information for additional information.
- Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. Exelon early adopted and retrospectively applied the new guidance to when the effects of the TCJA were recognized and, accordingly, recasted its December 31, 2017 AOCI and retained earnings in its Consolidated Balance Sheet and Consolidated Statement of Changes in Shareholders' Equity. Exelon's accounting policy is to release the stranded tax effects from AOCI related to its pension and OPEB plans under a portfolio (or aggregate) approach as an entire pension or OPEB plan is liquidated or terminated. See Note 2 — New Accounting Standards for additional information.
- Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. Exelon applied this guidance retrospectively for the presentation of the service and other non-service costs components of net benefit cost and, accordingly, have recasted those amounts, which were not material, in its Consolidated Statement of Operations and Comprehensive Income in prior periods presented. As part of the adoption, Exelon elected the practical expedient that permits an employer to use the amounts disclosed in its pension and other postretirement benefit plan note for the comparative periods as the estimation basis for applying the retrospective presentation requirements. See Note 14 — Retirement Benefits for additional information.
- Revenue from Contracts with Customers. The Registrants applied the new guidance using the full retrospective method and, accordingly, have recasted certain amounts in their Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Changes in Shareholders' Equity and Combined Notes to Consolidated Financial Statements in the prior periods presented. The amounts recasted in the Registrants' Consolidated Statements of Operations and Comprehensive Income are shown in the table below. The amounts recasted in the Registrants' Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Changes in Shareholders' Equity and Combined Notes to Consolidated Financial Statements were not material. See Note 5 — Revenue from Contracts with Customers for additional information.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended September 30, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating Revenues - As reported									
Competitive business revenues	$4,456	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	4,313	—	—	—	—	—	—	—	—
Operating revenues	—	4,455	—	—	—	—	—	—	—
Electric operating revenues	—	—	1,568	660	657	1,280	603	307	370
Natural gas operating revenues	—	—	—	53	78	18	—	18	—
Operating revenues from affiliates	—	296	3	2	3	12	1	2	—
Total operating revenues	$8,769	$ 4,751	$1,571	$715	$738	$1,310	$604	$327	$370
Operating Revenues - Adjustments									
Competitive business revenues	$(1)	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	(54)	—	—	—	—	—	—	—	—
Operating revenues	—	(1)	—	—	—	—	—	—	—
Electric operating revenues	—	—	(16)	—	(31)	(2)	(3)	1	—
Natural gas operating revenues	—	—	—	—	(5)	—	—	—	—
Revenues from alternative revenue programs	54	—	16	—	36	2	3	(1)	—
Operating revenues from affiliates	—	—	—	—	—	—	—	—	—
Total operating revenues	$(1)	$ (1)	$—	$—	$—	$—	$—	$—	$—
Operating Revenues - Retrospective application									
Competitive business revenues	$4,455	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	4,259	—	—	—	—	—	—	—	—
Operating revenues	—	4,454	—	—	—	—	—	—	—
Electric operating revenues	—	—	1,552	660	626	1,278	600	308	370
Natural gas operating revenues	—	—	—	53	73	18	—	18	—
Revenues from alternative revenue programs	54	—	16	—	36	2	3	(1)	—
Operating revenues from affiliates	—	296	3	2	3	12	1	2	—
Total operating revenues	$8,768	$ 4,750	$1,571	$715	$738	$1,310	$604	$327	$370

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Nine Months Ended September 30, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating Revenues - As reported									
Competitive business revenues	$12,924	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	12,225	—	—	—	—	—	—	—	—
Operating revenues	—	12,918	—	—	—	—	—	—	—
Electric operating revenues	—	—	4,215	1,798	1,890	3,417	1,645	860	913
Natural gas operating revenues	—	—	—	338	461	105	—	105	—
Operating revenues from affiliates	—	894	12	5	12	35	4	6	2
Total operating revenues	$25,149	$ 13,812	$4,227	$2,141	$2,363	$3,557	$1,649	$971	$915
Operating Revenues - Adjustments									
Competitive business revenues	$31	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	(191)	—	—	—	—	—	—	—	—
Operating revenues	—	31	—	—	—	—	—	—	—
Electric operating revenues	—	—	(48)	—	(79)	(41)	(23)	(9)	(9)
Natural gas operating revenues	—	—	—	—	(23)	—	—	—	—
Revenues from alternative revenue programs	191	—	48	—	102	41	23	9	9
Operating revenues from affiliates	—	—	—	—	—	—	—	—	—
Total operating revenues	$31	$ 31	$—	$—	$—	$—	$—	$—	$—
Operating Revenues - Retrospective application									
Competitive business revenues	$12,955	$ —	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	12,034	—	—	—	—	—	—	—	—
Operating revenues	—	12,949	—	—	—	—	—	—	—
Electric operating revenues	—	—	4,167	1,798	1,811	3,376	1,622	851	904
Natural gas operating revenues	—	—	—	338	438	105	—	105	—
Revenues from alternative revenue programs	191	—	48	—	102	41	23	9	9
Operating revenues from affiliates	—	894	12	5	12	35	4	6	2
Total operating revenues	$25,180	$ 13,843	$4,227	$2,141	$2,363	$3,557	$1,649	$971	$915

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Revenues (All Registrants)

Operating Revenues. The Registrants' operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of energy commodities and related products and services, utility revenues from alternative revenue programs (ARP), and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that the entities expect to be entitled to in exchange for those goods or services. 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 natural gas tariff sales, distribution and transmission services. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 5 — Revenue from Contracts with Customers and Note 6 —Regulatory Matters for additional information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly sale or purchase position. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Registrants in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. To the extent a Utility Registrant receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. See Note 6 — Regulatory Matters and Note 10 — Derivative Financial Instruments for additional information.

Taxes Directly Imposed on Revenue-Producing Transactions. The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees that are levied by state or local governments on the sale or distribution of natural gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed directly on the Registrants. The Registrants do not recognize revenue or expense in their Consolidated Statements of Operations and Comprehensive Income when these taxes are imposed on the customer, such as sales taxes. However, when these taxes are imposed directly on the Registrants, such as gross receipts taxes or other surcharges or fees, the Registrants recognize revenue for the taxes collected from customers along with an offsetting expense. See Note 18 — Supplemental Financial Information for Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's utility taxes that are presented on a gross basis.

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2. New Accounting Standards (All Registrants)
New Accounting Standards Adopted: In 2018, the Registrants have adopted the following new authoritative accounting guidance issued by the FASB.
Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (Issued February 2018): Provides an election for a reclassification from AOCI to Retained earnings to eliminate the stranded tax effects resulting from the TCJA. This standard is effective January 1, 2019, with early adoption permitted, and may be applied either in the period of adoption or retrospective to each period in which the effects of the TCJA were recognized. Exelon early adopted this standard during the first quarter 2018 and elected to apply the guidance retrospectively as of December 31, 2017, which resulted in an increase to Exelon’s Retained earnings and Accumulated other comprehensive loss of $539 million related to deferred income taxes associated with Exelon’s pension and OPEB obligations. There was no impact for Generation or the Utility Registrants.
See Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K for information on other new accounting standards issued and adopted as of January 1, 2018.
New Accounting Standards Issued and Not Yet Adopted as of September 30, 2018: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements as of September 30, 2018. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation that such standards will not significantly impact the Registrants' financial reporting.
Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The standard is effective January 1, 2019. Early adoption is permitted; however, the Registrants will not early adopt the standard. The issued guidance required a modified retrospective transition approach, which requires lessees and lessors to recognize and measure leases at the beginning of the earliest period presented (January 1, 2017). In July 2018, the FASB issued an amendment to the standard giving entities the option to apply the requirements of the standard in the period of adoption (January 1, 2019) with no restatement of prior periods. Exelon will elect this expedient.
The new guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only finance lease liabilities (referred to as capital leases) are recognized in the balance sheet. In addition, the definition of a lease has been revised which may result in changes to the classification of an arrangement as a lease. Under the new guidance, an arrangement that conveys the right to control the use of an identified asset by obtaining substantially all of its economic benefits and directing how it is used is a lease, whereas the current definition focuses on the ability to control the use of the asset or to obtain its output. Quantitative and qualitative disclosures related to the amount, timing and judgments of an entity’s accounting for leases and the related cash flows are expanded. Disclosure requirements apply to both lessees and lessors, whereas current disclosures relate only to lessees. Significant changes to lease systems, processes and procedures are required to implement the requirements of the new standard. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. Lessor accounting is also largely unchanged.
The standard provides a number of transition practical expedients that entities may elect. These include a "package of three" expedients that must be taken together and allow entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not

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reassess initial direct costs associated with existing leases. The Registrants will elect this practical expedient.
In January 2018, the FASB issued additional guidance which provides another optional transition practical expedient. This practical expedient allows entities to not evaluate land easements under the new guidance at adoption if they were not previously accounted for as leases. The Registrants will elect this practical expedient.
The Registrants have assessed the lease standard and are executing a detailed implementation plan in preparation for adoption on January 1, 2019. Key activities in the implementation plan include:

- Developing a complete lease inventory and abstracting the required data attributes into a lease accounting system that supports the Registrants' lease portfolios and integrates with existing systems.
- Evaluating the transition practical expedients available under the guidance.
- Identifying, assessing and documenting technical accounting issues, policy considerations and financial reporting implications.
- Identifying and implementing changes to processes and controls to ensure all impacts of the new guidance are effectively addressed.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity's current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. The Registrants are currently assessing the impacts of this standard.
Goodwill Impairment (Issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, Generation, ComEd, PHI and DPL have goodwill as of September 30, 2018. This updated guidance is not currently expected to impact the Registrants' financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.
Derivatives and Hedging (Issued September 2017): Allows more financial and nonfinancial hedging strategies to be eligible for hedge accounting. The amendments are intended to more closely align hedge accounting with companies' risk management strategies, simplify the application of hedge accounting, and increase transparency as to the scope and results of hedging programs. There are also amendments related to effectiveness testing and disclosure requirements. The standard is effective January 1, 2019, with early adoption permitted, and must be applied using a modified retrospective transition approach. Given the de-designation of hedge accounting relationships as of July 1, 2018, this standard is not expected to impact the Registrants' financial reporting as discussed in Note 10 - Derivative Financial Instruments.

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Cloud Computing Arrangements (Issued August 2018): Aligns the requirements for capitalizing costs incurred to implement a cloud computing arrangement with the internal-use software guidance. As a result, certain implementation costs incurred in a cloud computing arrangement that are currently expensed as incurred will be deferred and amortized over the non-cancellable term of the arrangement plus any reasonably certain renewal periods. The standard is effective January 1, 2020, with early adoption permitted, and can be applied using either a prospective or retrospective transition approach. A retrospective approach requires a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. The Registrants are currently assessing the impacts of this standard.

Defined Benefit Plan Disclosures (Issued August 2018): Eliminates existing disclosure requirements related to amounts in accumulated other comprehensive income expected to be recognized in net periodic benefit cost over the next year and the effects of a one-percentage-point change in the assumed health care cost trend rates. In addition, new disclosures were added such as the weighted-average interest crediting rates for cash balance plans and an explanation for the reasons for significant gains and losses related to changes in the benefit obligation. The standard is effective January 1, 2021, with early adoption permitted, and must be applied retrospectively. Exelon will early adopt this standard in the fourth quarter 2018.

Fair Value Measurement Disclosures (Issued August 2018): Removes, modifies and adds disclosure requirements for fair value measurements and aims to reduce costs for preparers and improve the usefulness of information for financial statement users. The standard is effective January 1, 2020, with early adoption permitted, and most amendments must be applied retrospectively with the exception of three amendments which must be applied prospectively. In addition, entities are permitted to delay adoption of the additional disclosure requirements until the effective date and early adopt the removal or modified disclosure requirements. The Registrants are currently assessing the impacts of this standard as well as the potential to early adopt.

3. Variable Interest Entities (All Registrants)

A VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest) or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly affect the entity’s economic performance.

At September 30, 2018 and December 31, 2017, Exelon, Generation, PHI and ACE collectively consolidated five VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see Consolidated Variable Interest Entities below). As of September 30, 2018 and December 31, 2017, Exelon and Generation collectively had significant interests in seven 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 Variable Interest Entities below).

Consolidated Variable Interest Entities

As of September 30, 2018 and December 31, 2017, Exelon's and Generation's consolidated VIEs consist of:

- energy related companies involved in distributed generation, backup generation and energy development
- renewable energy project companies formed by Generation to build, own and operate renewable power facilities

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- certain retail power and gas companies for which Generation is the sole supplier of energy, and
- CENG.

As of September 30, 2018 and December 31, 2017, Exelon's, PHI's and ACE's consolidated VIE consist of:

- ATF, 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.

As of September 30, 2018 and December 31, 2017, ComEd, PECO, BGE, Pepco and DPL did not have any material consolidated VIEs.

As of September 30, 2018 and December 31, 2017, Exelon and Generation provided the following support to their respective consolidated VIEs:

- Generation provides operating and capital funding to the renewable energy project companies and there is limited recourse to Generation related to certain renewable energy project companies.
- Generation provides operating and capital funding to one of the energy related companies involved in backup generation.
- Generation provides approximately $34 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.
- Exelon and Generation, where indicated, provide the following support to CENG:
- under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs were suspended during the term of the RSSA, through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017,
- Generation provided a $400 million loan to CENG. As of September 30, 2018, the remaining obligation is $194 million,
- 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 17 — Commitments and Contingencies for additional information),
- Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance,
- 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

As of September 30, 2018 and December 31, 2017, Exelon, PHI and ACE provided the following support to their respective consolidated VIE:

- In the case of ATF, 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. During the three and nine months ended September 30, 2018, ACE transferred $9 million and $23 million to ATF, respectively. During the three and nine months ended September 30, 2017, ACE transferred $11 million and $39 million to ATF, respectively.

For each of the consolidated VIEs, except as otherwise noted:

- the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;
- Exelon, Generation, PHI and ACE did not provide any additional material financial support to the VIEs;
- Exelon, Generation, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and
- the creditors of the VIEs did not have recourse to Exelon's, Generation's, PHI's or ACE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in the Registrants' consolidated financial statements at September 30, 2018 and December 31, 2017 are as follows:

	September 30, 2018				December 31, 2017			
	Exelon[(a)]	Generation	PHI[(a)]	ACE	Exelon[(a)]	Generation	PHI[(a)]	ACE
Current assets	$891	$ 881	$ 10	$ 7	$662	$ 652	$ 10	$ 6
Noncurrent assets	9,259	9,233	26	19	9,317	9,286	31	23
Total assets	$10,150	$ 10,114	$ 36	$ 26	$9,979	$ 9,938	$ 41	$ 29
Current liabilities	$329	$ 303	$ 26	$ 23	$308	$ 272	$ 36	$ 32
Noncurrent liabilities	3,284	3,232	52	45	3,316	3,250	66	58
Total liabilities	$3,613	$ 3,535	$ 78	$ 68	$3,624	$ 3,522	$ 102	$ 90

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors or beneficiaries do not have recourse to the general credit of the Registrants. As of September 30, 2018 and December 31, 2017, these assets and liabilities primarily consisted of the following:

	September 30, 2018				December 31, 2017			
	Exelon[(a)]	Generation	PHI[(a)]	ACE	Exelon[(a)]	Generation	PHI[(a)]	ACE
Cash and cash equivalents	$316	$ 316	$ —	$ —	$126	$ 126	$ —	$ —
Restricted cash	77	70	7	7	64	58	6	6
Accounts receivable, net								
Customer	165	165	—	—	170	170	—	—
Other	30	30	—	—	25	25	—	—
Inventory, net								
Materials and supplies	214	214	—	—	205	205	—	—
Other current assets	65	62	3	—	45	41	4	—
Total current assets	867	857	10	7	635	625	10	6
Property, plant and equipment, net	6,158	6,158	—	—	6,186	6,186	—	—
Nuclear decommissioning trust funds	2,523	2,523	—	—	2,502	2,502	—	—
Other noncurrent assets	256	230	26	19	274	243	31	23
Total noncurrent assets	8,937	8,911	26	19	8,962	8,931	31	23
Total assets	$9,804	$ 9,768	$ 36	$ 26	$9,597	$ 9,556	$ 41	$ 29
Long-term debt due within one year	$97	$ 72	$ 25	$ 22	$102	$ 67	$ 35	$ 31
Accounts payable	128	128	—	—	114	114	—	—
Accrued expenses	73	72	1	1	67	66	1	1
Unamortized energy contract liabilities	16	16	—	—	18	18	—	—
Other current liabilities	14	14	—	—	7	7	—	—
Total current liabilities	328	302	26	23	308	272	36	32
Long-term debt	1,087	1,035	52	45	1,154	1,088	66	58
Asset retirement obligations	2,116	2,116	—	—	2,035	2,035	—	—
Other noncurrent liabilities	75	75	—	—	121	121	—	—
Total noncurrent liabilities	3,278	3,226	52	45	3,310	3,244	66	58
Total liabilities	$3,606	$ 3,528	$ 78	$ 68	$3,618	$ 3,516	$ 102	$ 90

(a) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.

Unconsolidated Variable Interest Entities

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 on Exelon's and Generation's Consolidated Balance Sheets in

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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. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

As of September 30, 2018 and December 31, 2017, Exelon's and Generation's unconsolidated VIEs consist of:

- Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.
- Asset sale agreement with ZionSolutions, LLC and EnergySolutions, Inc. in which Generation has a variable interest but has concluded that consolidation is not required.
- Equity investments in distributed energy companies for which Generation has concluded that consolidation is not required.

As of September 30, 2018 and December 31, 2017, the Utility Registrants did not have any material unconsolidated VIEs.

As of September 30, 2018 and December 31, 2017, Exelon and Generation had significant unconsolidated variable interests in seven VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $15 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $15 million included in Investments on Exelon's and Generation's Consolidated Balance Sheets. The risk of a loss was assessed to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss.

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

September 30, 2018	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 606	$ 481	$1,087
Total liabilities[(a)]	36	221	257
Exelon's ownership interest in VIE[(a)]	—	232	232
Other ownership interests in VIE[(a)]	570	28	598
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments	—	232	232
Contract intangible asset	8	—	8
Net assets pledged for Zion Station decommissioning[(b)]	—	—	—

December 31, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 625	$ 509	$1,134
Total liabilities[(a)]	37	228	265
Exelon's ownership interest in VIE[(a)]	—	251	251
Other ownership interests in VIE[(a)]	588	30	618
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments	—	251	251
Contract intangible asset	8	—	8
Net assets pledged for Zion Station decommissioning[(b)]	2	—	2

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(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon’s or Generation’s Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon’s and Generation’s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $9 million and $39 million as of September 30, 2018 and December 31, 2017, respectively; offset by payables to ZionSolutions, LLC of $9 million and $37 million as of September 30, 2018 and December 31, 2017, respectively. These items are included to provide information regarding the relative size of the ZionSolutions, LLC unconsolidated VIE. See Note 13 — Asset Retirement Obligations for additional information.

For each of the unconsolidated VIEs, Exelon and Generation have assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these VIEs.

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

Acquisition of FirstEnergy Solutions Load Business

On July 9, 2018, Generation entered into an Asset Purchase Agreement (the Purchase Agreement) with FirstEnergy Solutions Corporation (FirstEnergy). Pursuant to the Purchase Agreement, FirstEnergy will assign all of its retail electricity and wholesale load serving contracts and certain other related commodity contracts to Generation for an all cash purchase price of $140 million. Pursuant to the

Purchase Agreement, Generation has agreed to use its commercially reasonable efforts to replace the guarantees and other credit support currently being provided by FirstEnergy in support of the ongoing competitive retail businesses and to reimburse FirstEnergy for any payments arising pursuant to such arrangements continuing for any post-closing period.

The transaction is expected to close in the fourth quarter of 2018. The closing of the transaction is subject to certain conditions including the approval of the Purchase Agreement by the United States Bankruptcy Court for the Northern District of Ohio following the auction and expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. Either party may terminate the Purchase Agreement if the transaction has not been consummated by December 31, 2018. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

Acquisition of Handley Generating Station

On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware, which resulted in Exelon and Generation deconsolidating EGTP's assets and liabilities from their consolidated financial statements in the fourth quarter of 2017. Concurrently with the Chapter 11 filings, Generation entered into an asset purchase agreement to acquire one of EGTP's generating plants, the Handley Generating Station, subject to a potential adjustment for fuel oil and assumption of certain liabilities. In the Chapter 11 Filings, EGTP requested that the proposed acquisition of the Handley Generating Station be consummated through a court-approved and supervised sales process. The acquisition was approved by the Bankruptcy Court in January 2018 and closed on April 4, 2018 for a purchase price of $62 million. The Chapter 11 bankruptcy proceedings were finalized on April 17, 2018, resulting in the ownership of EGTP assets (other than the Handley Generating Station) being transferred to EGTP's lenders.

Acquisition of James A. FitzPatrick Nuclear Generating Station

On March 31, 2017, Generation acquired the 842 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $289 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $179 million. As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shut down the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick's electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034.

The fair values of FitzPatrick’s assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices. The valuations performed in the first quarter of 2017 to determine the fair value of the FitzPatrick assets acquired and liabilities assumed were updated in the third quarter of 2017. The purchase price allocation is now final.

For the three months ended March 31, 2017, an after-tax bargain purchase gain of $226 million is included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and primarily reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant. During the third quarter of 2017, Exelon and Generation

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recorded an additional after-tax bargain purchase gain of $7 million for the three months ended September 30, 2017. The total after-tax bargain purchase gain recorded at Exelon and Generation was $233 million for the twelve months ended December 31, 2017. See Note 13 — Asset Retirement Obligations and Note 14 — Retirement Benefits for additional information regarding the FitzPatrick decommissioning ARO and pension and OPEB updates.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation:

Cash paid for purchase price	$110
Cash paid for net cost reimbursement	125
Nuclear fuel transfer	54
Total consideration transferred	$289
Identifiable assets acquired and liabilities assumed	
Current assets	$60
Property, plant and equipment	298
Nuclear decommissioning trust funds	807
Other assets[(a)]	114
Total assets	$1,279
Current liabilities	$6
Nuclear decommissioning ARO	444
Pension and OPEB obligations	33
Deferred income taxes	149
Spent nuclear fuel obligation	110
Other liabilities	15
Total liabilities	$757
Total net identifiable assets, at fair value	$522
Bargain purchase gain (after-tax)	$233

(a) Includes a $110 million asset associated with a contractual right to reimbursement from the New York Power Authority (NYPA), a prior owner of FitzPatrick, associated with the DOE one-time fee obligation. See Note 23-Commitments and Contingencies of the Exelon 2017 Form 10-K for additional information regarding SNF obligations to the DOE.

Exelon and Generation incurred $16 million and $47 million of merger and integration costs related to FitzPatrick for the three and nine months ended September 30, 2017, respectively, which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Exelon and Generation did not incur any merger and integration costs related to FitzPatrick for the three and nine months ended September 30, 2018.

Disposition of Oyster Creek

On July 31, 2018, Generation entered into an agreement with Holtec International (Holtec) and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), for the sale and decommissioning of the Oyster Creek Generating Station (Oyster Creek) located in Forked River, New Jersey. On September 17, 2018, Oyster Creek permanently ceased generation operations.

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Under the terms of the transaction, Generation will transfer to OCEP substantially all the assets associated with Oyster Creek, including assets held in NDT funds, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of spent fuel until the spent fuel is moved offsite. In addition to the assumption of liability for the full decommissioning and ongoing management of spent fuel, other consideration to be received in the transaction is contingent on several factors, including a requirement that Generation deliver a minimum NDT fund balance at closing, subject to adjustment for specific terms that include income taxes that would be imposed on any net unrealized built-in gains and certain decommissioning activities to be performed during the pre-close period after the unit shuts down in the fall of 2018 and prior to the anticipated close of the transaction. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to Generation upon the occurrence of specified events.

As a result of the transaction, in the third quarter of 2018, Exelon and Generation reclassified certain Oyster Creek assets and liabilities on Exelon’s and Generation’s Consolidated Balance Sheets as held for sale at their respective fair values. Upon remeasurement of the Oyster Creek ARO in the third quarter of 2018, Exelon and Generation recognized an $84 million pre-tax charge to Operating and maintenance expense.

Completion of the transaction contemplated by the sale agreement is subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and the receipt of a private letter ruling from the IRS. Generation currently anticipates satisfaction of the closing conditions to occur in the second half of 2019.

Other Asset Disposition

In December 2017, Generation entered into an agreement to sell its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution systems. As a result, as of December 31, 2017, certain assets and liabilities were classified as held for sale and included in the Other current assets and Other current liabilities balances on Exelon's and Generation's Consolidated Balance Sheet. On February 28, 2018, Generation completed the sale of its interest for $87 million, resulting in a pre-tax gain which is included within Gain on sales of assets and businesses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In June 2018, additional proceeds were received, and a pre-tax gain was recorded within Gain on sales of assets and businesses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

5. 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. The performance obligations associated with these sources of revenue are further discussed below.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, the Registrants have the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, the Registrant's have elected to use the right to invoice practical expedient for the contracts within these revenue categories and generally recognize revenue in the amount for

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which they have the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Competitive Power Sales (Exelon and Generation)

Generation sells power and other energy-related commodities to both wholesale and retail customers across multiple geographic regions through its customer-facing business, Constellation. Power sale contracts generally contain various performance obligations including the delivery of power and other energy-related commodities such as capacity, ZECs, RECs or other ancillary services. Certain performance obligations such as power and capacity are generally delivered over time whereas other performance obligations such as RECs and ZECs are generally delivered at a point in time. In either case, revenues related to all of the performance obligations in such bundled power sale contracts are generally recognized concurrently as the power is generated. Except as noted in the paragraph below, there are no significant judgments in allocating the transaction price since all performance obligations are satisfied simultaneously upon the generation of power. Payment terms generally require that the customers pay for the power or the energy-related commodity within the month following delivery to the customer and there are generally no significant financing components.

Certain contracts may contain limits on the total amount of revenue we are able to collect over the entire term of the contract. In such cases, the Registrants estimate the total consideration expected to be received over the term of the contract net of the constraint and allocate the expected consideration to the performance obligations in the contract such that revenue is recognized ratably over the term of the entire contract as the performance obligations are satisfied.

Competitive Natural Gas Sales (Exelon and Generation)

Generation sells natural gas on a full requirements basis or for an agreed upon volume to both commercial and residential customers. The primary performance obligation associated with natural gas sale contracts is the delivery of the natural gas to the customer. Revenues related to the sale of natural gas are recognized over time as the natural gas is delivered to and consumed by the customer. Payment from customers is typically due within the month following delivery of the natural gas to the customer and there are generally no significant financing components.

Other Competitive Products and Services (Exelon and Generation)

Generation also sells other energy-related products and services such as long-term construction and installation of energy efficiency assets and new power generating facilities, primarily to commercial and industrial customers. These contracts generally contain a single performance obligation, which is the construction and/or installation of the asset for the customer. The average contract term for these projects is approximately 18 months. Revenues, and associated costs, are recognized throughout the contract term using an input method to measure progress towards completion. The method recognizes revenue based on the various inputs used to satisfy the performance obligation, such as costs incurred and total labor hours expended. The total amount of revenue that will be recognized is based on the agreed upon contractually-stated amount. Payments from customers are typically due within 30 or 45 days from the date the invoice is generated and sent to the customer.

Regulated Electric and Gas Tariff Sales (Exelon and the Utility Registrants)

The Utility Registrants sell electricity and electricity distribution services to residential, commercial, industrial and governmental customers through regulated tariff rates approved by their state regulatory commissions. PECO, BGE and DPL also sell natural gas and gas distribution services to residential, commercial, and industrial customers through regulated tariff rates approved by their state regulatory commissions. The performance obligation associated with these tariff sale contracts is the delivery of electricity and/or natural gas. Tariff sales are generally considered daily contracts given that customers

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can discontinue service at any time. Revenues are generally recognized over time (each day) as the electricity and/or natural gas is delivered to customers. Payment terms generally require that customers pay for the services within the month following delivery of the electricity or natural gas to the customer and there are generally no significant financing components or variable consideration.

Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While the Utility Registrants are required under state legislation to bill their customers for the supply and distribution of electricity and/or natural gas, they recognize revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.

Regulated Transmission Services (Exelon and the Utility Registrants)

Under FERC's open access transmission policy, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates approved by FERC. The Utility Registrants are members of PJM, the regional transmission organization designated by FERC to coordinate the movement of wholesale electricity in PJM's region, which includes portions of the mid-Atlantic and Midwest. In accordance with FERC-approved rules, the Utility Registrants and other transmission owners in the PJM region make their transmission facilities available to PJM, which directs and controls the operation of these transmission facilities and accordingly compensates the Utility Registrants and other transmission owners. The performance obligations associated with the Utility Registrants' contract with PJM include (i) Network Integration Transmission Services (NITS), (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid. These performance obligations are satisfied over time, and Utility Registrants utilize output methods to measure the progress towards their completion. Passage of time is used for NITS and access to the wholesale grid and MWhs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services. PJM pays the Utility Registrants for these services on a weekly basis and there are no financing components or variable consideration.

Costs to Obtain or Fulfill a Contract with a Customer (Exelon and Generation)

Generation incurs incremental costs in order to execute certain retail power and gas sales contracts. These costs primarily relate to retail broker fees and sales commissions. Generation has capitalized such contract acquisition costs in the amount of $30 million and $26 million as of September 30, 2018 and December 31, 2017, respectively, within Other current assets and Other deferred debits in Exelon's and Generation's Consolidated Balance Sheets. These costs are capitalized when incurred and amortized using the straight-line method over the average length of such retail contracts, which is approximately 2 years. Exelon and Generation recognized amortization expense associated with these costs in the amount of $6 million and $16 million for the three and nine months ended September 30, 2018, respectively, and $7 million and $24 million for the three and nine months ended September 30, 2017, respectively, within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Generation does not incur material costs to fulfill contracts with customers that are not already capitalized under existing guidance. In addition, the Utility Registrants do not incur any material costs to obtain or fulfill contracts with customers.

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 within Other current assets and Accounts receivable, net -

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Customer, respectively, within Exelon's and Generation's Consolidated Balance Sheets. The following table provides a rollforward of the contract assets reflected on Exelon's and Generation's Consolidated Balance Sheets from January 1, 2018 to September 30, 2018:

Contract Assets	Exelon and Generation
Balance as of January 1, 2018	$ 283
Increases as a result of changes in the estimate of the stage of completion	34
Amounts reclassified to receivables	(120)
Balance at September 30, 2018	$ 197

The Utility Registrants do not have any contract assets.

Contract Liabilities

Generation records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. Generation records contract liabilities within Other current liabilities and Other noncurrent liabilities within Exelon's and Generation's Consolidated Balance Sheets. The following table provides a rollforward of the contract liabilities reflected on Exelon's and Generation's Consolidated Balance Sheet from January 1, 2018 to September 30, 2018:

Contract Liabilities	Exelon and Generation
Balance as of January 1, 2018	$ 35
Increases as a result of additional cash received or due	389
Amounts recognized into revenues	(387)
Balance at September 30, 2018	$ 37

The Utility Registrants also record contract liabilities when consideration is received prior to the satisfaction of the performance obligations. As of September 30, 2018 and December 31, 2017, the Utility Registrants' contract liabilities were immaterial.

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, 2018. Generation has elected the exemption which permits the exclusion from this disclosure of certain variable contract consideration. As such, the majority of Generation's power and gas sales contracts are excluded from this disclosure as they contain variable volumes and/or variable pricing. Thus, 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.

The majority of the Utility Registrants' tariff sale contracts are generally day-to-day contracts and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure. Further, the Utility Registrants have elected the exemption to not disclose the transaction price allocation to remaining performance obligations for contracts with an original expected duration of one year or less. As such, gas and electric tariff sales contracts and transmission revenue contracts are excluded from this disclosure.

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	2019	2020	2021	2022	2023 and thereafter	Total
Exelon	$647	$302	$119	$47	$ 137	$1,252
Generation	647	302	119	47	137	1,252

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

6. Regulatory Matters (All Registrants)

Except for the matters noted below, the disclosures set forth in Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K reflect, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Tax Cuts and Jobs Act (Exelon and ComEd). On January 18, 2018, the ICC approved ComEd's petition filed on January 5, 2018 seeking approval to pass back to customers beginning February 1, 2018 $201 million in tax savings resulting from the enactment of the TCJA through a reduction in electric distribution rates. The amounts being passed back to customers reflect the benefit of lower income tax rates beginning January 1, 2018 and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. See Note 12 — Income Taxes for additional information on Corporate Tax Reform.

Electric Distribution Formula Rate (Exelon and ComEd). On April 16, 2018, ComEd filed its annual distribution formula rate update with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2019 after the ICC's review and approval, which is due by December 2018. The revenue requirement requested is based on 2017 actual costs plus projected 2018 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2017 to the actual costs incurred that year. ComEd's 2018 filing request includes a total decrease to the revenue requirement of $23 million, reflecting a decrease of $58 million for the initial revenue requirement for 2018 and an increase of $35 million related to the annual reconciliation for 2017. The revenue requirement for 2018 and the annual reconciliation for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points. See table below for ComEd's regulatory assets associated with its electric distribution formula rate. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on ComEd's distribution formula rate filings.

During the first quarter 2018, ComEd revised its electric distribution formula rate, as provided for by FEJA, to reduce the ROE collar calculation from plus or minus 50 basis points to 0 basis points beginning with the reconciliation filed in 2018 for the 2017 calendar year. This revision effectively offsets the favorable or unfavorable impacts to ComEd's electric distribution formula rate revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer. ComEd began reflecting the impacts of this change in its electric distribution formula rate regulatory asset in the first quarter 2017.

Energy Efficiency Formula Rate (Exelon and ComEd). On June 1, 2018, ComEd filed its annual energy efficiency formula rate update with the ICC. The filing establishes the 2019 application year revenue requirement used to set the rates that will take effect in January 2019 after the ICC's review and approval, which is due by December 2018. The revenue requirement requested is based on 2017 actual costs plus projected 2018 and 2019 expenditures as well as an annual reconciliation of the revenue requirement in effect in 2017 to the actual costs incurred that year. ComEd's 2018 filing request includes a total increase to the revenue requirement of $39 million, reflecting an increase of $38 million for the initial revenue requirement for 2018 and an increase of $1 million related to the annual reconciliation for 2017. The revenue requirement for the 2019 application year provides for a weighted average debt and equity return on rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

Zero Emission Standard (Exelon, Generation and ComEd). Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue. Winning bidders are entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the three months ended September 30, 2018, Generation recognized revenue of $61 million. During the nine months ended September 30, 2018, Generation recognized revenue of $315 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

ComEd recovers all costs associated with purchasing ZECs through a rate rider that provides for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd's retail customers in subsequent periods with interest. ComEd began billing its retail customers under its new ZEC rate rider on June 1, 2017.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state's ZEC program violates certain provisions of the U.S. Constitution. One lawsuit was filed by customers of ComEd, led by the Village of Old Mill Creek, and the other was brought by the EPSA and three other electric suppliers. Both lawsuits argued that the Illinois ZEC program would distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices and sought a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. On July 14, 2017, the district court granted the motions to dismiss. On July 17, 2017, the plaintiffs appealed the decision to the U.S. Court of Appeals for the Seventh Circuit. On February 21, 2018, the U.S. Court of Appeals for the Seventh Circuit issued an order inviting the Solicitor General to express the views of the United States on the matter. On May 29, 2018, the Solicitor General and FERC filed its brief in the U.S. Court of Appeals for the Seventh Circuit stating that the Illinois ZEC program does not violate federal law or interfere with FERC's authority to regulate wholesale power markets. On September 13, 2018, the U.S. Circuit Court of Appeals for the Seventh Circuit affirmed the lower court's dismissal of both lawsuits. On September 27, 2018, the plaintiffs filed a request for a panel rehearing with the U.S. Circuit Court of Appeals for the Seventh Circuit. On October 9, 2018, the U.S. Circuit Court of Appeals for the Seventh Circuit panel denied the request for rehearing.

See Note 8 — Early Plant Retirements for additional information regarding the economic challenges facing Generation's Clinton and Quad Cities nuclear plants and the expected benefits of the ZES.

Pennsylvania Regulatory Matters

2018 Pennsylvania Electric Distribution Base Rate Case (Exelon and PECO). On March 29, 2018, PECO filed a request with the PAPUC seeking approval to increase its electric distribution base rates by $82 million beginning January 1, 2019. This requested amount includes the effect of an approximately $71 million reduction as a result of the ongoing annual tax savings beginning January 1, 2019 associated with the TCJA. The requested ROE was 10.95%. On August 28, 2018, PECO and interested parties filed with the PAPUC a petition for partial settlement for an increase of $25 million in annual electric distribution service revenues, which includes the effect of an approximately $71 million reduction as a result of the ongoing annual tax savings beginning January 1, 2019 associated with the TCJA. No overall ROE was specified in the partial settlement. On October 18, 2018, the Administrative Law Judges issued a Recommended Decision to the PAPUC that the partial settlement be approved without modification. A final ruling from the PAPUC is expected before December 31, 2018, and if approved, the new electric distribution base rates will become effective on January 1, 2019.

Tax Cuts and Jobs Act (Exelon and PECO). On May 17, 2018, the PAPUC issued an order to all Pennsylvania utility companies, including PECO, requiring that the annual tax savings beginning on January 1, 2018 associated with TCJA be passed back to customers. The order directs Pennsylvania utility companies without an existing base rate case, including PECO's gas distribution business, to start passing back the savings from January 1, 2018 onward through a negative surcharge mechanism to be effective on July 1, 2018. Pursuant to the May 17, 2018 order, PECO filed a negative surcharge mechanism and began on July 1, 2018, to return an estimated $4 million in annual 2018 tax savings to its natural gas distribution customers. For Pennsylvania utility companies with existing base rate cases, including PECO's electric distribution base rate case, the timing of when and how to pass the annual TCJA savings to customers will be resolved through the base rate case proceeding.

As part of the rate case filing referenced above, PECO is seeking approval to pass back to electric distribution customers $68 million in 2018 TCJA tax savings of which the majority will be passed back in January 2019 with the remainder refunded over the balance of the year. The TCJA tax savings would be an additional offset to the proposed increase to its electric distribution rates. The amounts being proposed to be passed back to customers reflect the respective annual benefits of lower income tax rates established upon enactment of the TCJA.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

Maryland Regulatory Matters

Tax Cuts and Jobs Act (Exelon, BGE, PHI, Pepco and DPL). On January 12, 2018, the MDPSC issued an order that directed each of BGE, Pepco and DPL to track the impacts of the TCJA beginning January 1, 2018 and file by February 15, 2018 how and when they expect to pass through such impacts to their customers.

On January 31, 2018, the MDPSC approved BGE's petition to pass back to customers $103 million in ongoing annual tax savings resulting from the enactment of the TCJA through a reduction in distribution base rates beginning February 1, 2018, of which $72 million and $31 million were related to electric and natural gas, respectively. The amounts being passed back to customers reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. BGE's natural gas distribution rate case filing in June 2018 included a request to provide to customers the natural gas portion of the January 2018 TCJA savings over a 5-year period.

On April 20, 2018, Pepco entered into a settlement agreement with several parties to resolve all issues in its pending electric distribution base rate case, including the treatment of the annual ongoing TCJA tax savings as well as the TCJA tax savings from January 1, 2018 through the expected effective date of the rate change. On May 31, 2018, the MDPSC issued an order approving the settlement agreement with an effective date of June 1, 2018. See discussion below for additional information.

On February 9, 2018, DPL filed with the MDPSC seeking approval to pass back to customers $13 million in ongoing annual TCJA tax savings through a reduction in electric distribution base rates beginning in 2018. On April 18, 2018, the MDPSC approved a settlement agreement to pass back to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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customers $14 million in ongoing annual TCJA tax savings through a reduction in electric distribution base rates beginning April 20, 2018. The amounts being passed back to customers reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. In addition, the MDPSC separately ordered DPL to provide a one-time bill credit to customers of $2 million in June 2018 representing the TCJA tax savings from January 1, 2018 through March 31, 2018.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). On December 1, 2017 (and as amended on January 22, 2018), BGE filed an application with the MDPSC seeking approval for a new gas infrastructure replacement plan and associated surcharge, effective for the five-year period from 2019 through 2023. On May 30, 2018, the MDPSC approved with modifications a new infrastructure plan and associated surcharge, subject to BGE's acceptance of the Order. On June 1, 2018, BGE accepted the MDPSC Order and the associated surcharge will be effective in rates beginning in January 2019. The new five-year plan calls for capital expenditures over the 2019-2023 timeframe of $732 million, with an associated revenue requirement of $200 million.

2018 Maryland Natural Gas Distribution Base Rates (Exelon and BGE). On June 8, 2018, and as amended on August 24, 2018 and October 12, 2018, BGE filed an application with the MDPSC to increase natural gas revenues by $61 million, reflecting a requested ROE of 10.5%. BGE expects a decision in the first quarter of 2019 but cannot predict how much of the requested increase the MDPSC will approve.

2018 Maryland Electric Distribution Base Rates (Exelon, PHI and Pepco). On January 2, 2018, Pepco filed an application with the MDPSC to increase its annual electric distribution base rates by $41 million, reflecting a requested ROE of 10.1%. On February 5, 2018, Pepco filed with the MDPSC an update to its current distribution base rate case to reflect $31 million in ongoing annual TCJA tax savings, thereby reducing the requested annual base rate increase to $11 million. On March 8, 2018, Pepco filed with the MDPSC a subsequent update to its electric distribution base rate case, which further reduced the requested annual base rate increase to $3 million. On April 20, 2018, Pepco entered into a settlement agreement with several parties to resolve all issues in the rate case and filed the settlement agreement with the MDPSC. The settlement agreement provides for a net decrease to annual electric distribution base rates of $15 million, which includes annual ongoing TCJA tax savings, and reflects a ROE of 9.5%. In addition, the settlement agreement separately provides a one-time bill credit to customers of approximately $10 million representing the TCJA tax savings from January 1, 2018 through the expected rate effective date of June 1, 2018. On May 31, 2018, the MDPSC issued an order approving the settlement agreement with an effective date of June 1, 2018. Pepco issued the $10 million to customers in July 2018.

2017 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL). On July 14, 2017, DPL filed an application with the MDPSC to increase its annual electric distribution base rates by $27 million, which was updated to $19 million on November 16, 2017, reflecting a requested ROE of 10.1%. On December 18, 2017, a settlement agreement was filed with the MDPSC wherein DPL will be granted a base rate increase of $13 million, and a ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset carrying costs. On February 9, 2018, the MDPSC approved the settlement agreement and the new rates became effective.

In the second quarter of 2018, DPL discovered a rate design issue in Maryland such that the current rates were not sufficient to collect the full amount of the $13 million revenue increase agreed to by the parties in the recent settlement. On September 5, 2018, the MDPSC approved DPL’s proposed revisions to resolve the rate design issue on a prospective basis, effective September 5, 2018.

Delaware Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and DPL). On January 16, 2018, the DPSC opened a docket indicating that DPL's TCJA tax savings would be addressed in its pending rate cases. See discussion below for further information on the proposed treatment of the TCJA tax savings in DPL's pending electric and natural gas distribution base rate cases.

2017 Delaware Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). On August 17, 2017 (as updated on February 9, 2018 to reflect $19 million and $7 million of ongoing annual TCJA tax savings for electric and natural gas, respectively), DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $12 million and $4 million, respectively, reflecting a requested ROE of 10.1%. The ongoing annual TCJA tax savings reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Of the proposed electric and natural gas rate increases, $2.5 million of each were put into effect in the fourth quarter 2017 and an additional $3 million and $1 million, respectively, were put into effect in the first quarter 2018, all of which are subject to refund based on the final DPSC order.

On June 27, 2018, DPL entered into a settlement agreement with all active parties in the proceeding related to its pending electric distribution base rate case. The settlement agreement provides for a net decrease to annual electric distribution base rates of $7 million, which includes annual ongoing TCJA tax savings, and reflects a ROE of 9.7%. In addition, the settlement agreement separately provides a one-time bill credit to customers of approximately $3 million representing the TCJA tax savings from February 1, 2018 through March 17, 2018, when full interim rates were put into effect. On August 21, 2018, the DPSC approved the settlement agreement as filed. DPL expects to issue the $3 million to customers in the fourth quarter of 2018.

On September 7, 2018 (as amended and restated on October 2, 2018), DPL entered into a partial settlement agreement with several parties in its pending gas distribution base rate case proceeding that provides for a net decrease to annual gas distribution base rates of $4 million, which includes annual ongoing TCJA tax savings, and reflects a ROE of 9.7%. In addition, the settlement agreement separately provides a one-time bill credit to customers of approximately $1 million, which includes the TCJA tax savings from February 1, 2018 through March 17, 2018, when full interim rates were put into effect. DPL expects a decision on the settlement agreement in the fourth quarter of 2018 but cannot predict if the DPSC will approve the settlement agreement as filed.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

District of Columbia Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and Pepco). On January 23, 2018, the DCPSC opened a rate proceeding directing Pepco to track the impacts of the TCJA beginning January 1, 2018 and file its plan to reduce the current revenue requirement by customer class by February 12, 2018. The DCPSC stated it will address the impact of the TCJA on future rates within Pepco's pending electric distribution base rate case discussed below.

On February 6, 2018, Pepco filed with the DCPSC seeking approval to pass back to customers $39 million in ongoing annual tax savings resulting from the enactment of the TCJA through a reduction to existing electric distribution base rates beginning in 2018. On April 17, 2018, Pepco entered into a settlement agreement with several parties to resolve all issues in its pending electric distribution base rate case, including the treatment of the annual ongoing TCJA tax savings as well as the TCJA tax savings from January 1, 2018 through the expected effective date of the rate change. On August 9, 2018, the DCPSC approved the settlement agreement with an effective date of August 13, 2018. See discussion below for additional information.

2017 District of Columbia Electric Distribution Base Rates (Exelon, PHI and Pepco). On December 19, 2017 (and updated on February 9, 2018), Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $66 million, reflecting a requested ROE of 10.1%. On April 17, 2018, Pepco entered into a settlement agreement with several parties to resolve both the pending electric distribution base rate case and the $39 million rate reduction request in the TCJA proceeding discussed above and filed the settlement agreement with the DCPSC. The settlement agreement provides for a net decrease to annual electric distribution rates of $24 million, which includes annual ongoing TCJA tax savings, and reflects a ROE of 9.525%. On August 9, 2018, the DCPSC approved the settlement agreement with an effective date of August 13, 2018. In addition, the settlement agreement separately provides for a one-time bill credit to customers of approximately $19 million representing the TCJA benefits for the period January 1, 2018 through the expected rate effective date of July 1, 2018. As rates did not go into effect until August 13, 2018, on September 7, 2018, Pepco submitted an updated filing for a one-time bill credit to customers of approximately $20 million, and an increase of $4 million to the customer base rate credit established in connection with the merger between Exelon and PHI for residential customers, representing the TCJA benefits for the period January 1, 2018 through August 12, 2018. Following the expiration of the comment period with no objections filed, Pepco issued the $20 million to customers in September 2018.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

New Jersey Regulatory Matters

Tax Cuts and Jobs Act (Exelon, PHI and ACE). On January 31, 2018, the NJBPU issued an order mandating that New Jersey utility companies, including ACE, pass any economic benefit from the TCJA to rate payers. The order directed New Jersey utility companies to file by March 2, 2018 proposed tariff sheets reflecting TCJA benefits, with new rates to be implemented in two phases. In addition, the NJBPU directed New Jersey utility companies to file by March 2, 2018 a Petition with the NJBPU outlining how they propose to refund any over-collection associated with revised rates not being in place from January 1, 2018 through March 31, 2018, with interest.

On March 2, 2018, ACE filed with the NJBPU seeking approval to pass back to customers $23 million in ongoing annual TCJA tax savings through a reduction in electric distribution base rates beginning in 2018. The amounts being passed back to customers would reflect the ongoing annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. On March 26, 2018, the NJBPU issued an order accepting ACE’s proposed bill reduction related to the lower income tax rates. A portion of the annual decrease in electric distribution base rates totaling approximately $13 million was effective as of April 1, 2018, but considered interim. On August 29, 2018, the NJBPU issued an order approving final rates with an effective date of September 8, 2018, which reflects the full amount of ACE’s proposed $23 million reduction, including a one-time bill credit to customers of approximately $6 million representing the TCJA tax savings from January 1, 2018 through June 30, 2018. ACE expects to issue the $6 million to customers in the fourth quarter of 2018. ACE's treatment of the TCJA tax savings for the period July 1, 2018 through the effective date of the final rates is the subject of ongoing discussions, and ACE anticipates that the NJBPU will issue a clarifying order in the fourth quarter of 2018.

See Note 12 — Income Taxes for additional information on Corporate Tax Reform and the table below for regulatory liabilities recognized during 2018 associated with TCJA tax savings that will be passed through future customer rates.

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ACE Infrastructure Investment Program Filing (Exelon, PHI and ACE). On February 28, 2018, ACE filed with the NJBPU the company's Infrastructure Investment Program (IIP) proposing to seek recovery of a series of investments through a new rider mechanism, totaling $338 million, between 2019-2022 to provide safe and reliable service for its customers. The IIP will allow for more timely recovery of investments made to modernize and enhance ACE's electric system. ACE currently expects a decision in this matter in the first quarter of 2019 but cannot predict if the NJBPU will approve the application as filed.

Update and Reconciliation of Certain Over and Under Recovered Balances (Exelon, PHI and ACE). On February 5, 2018, ACE submitted its 2018 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE's long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE's uncollectible accounts. As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate decrease of $19 million, including New Jersey sales and use tax. On May 22, 2018, the NJBPU approved a stipulation of settlement among certain interested parties providing for an overall annual rate decrease of $33 million, effective June 1, 2018. The rate decrease was placed into effect provisionally, subject to a review by the NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. This rate decrease will have no effect on ACE's operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism. The matter is pending at the NJBPU.

New Jersey Clean Energy Legislation (Exelon, Generation and ACE). On May 23, 2018, the Governor of New Jersey signed new legislation, which became effective immediately, that establishes and modifies New Jersey's clean energy and energy efficiency programs and solar and renewable energy portfolio standards. The new legislation expands the state's renewable portfolio standard to require that 50% of electric generation sold be from renewable energy sources by 2030; modifies the New Jersey solar renewable energy portfolio standard to require that 5.1% of electric generation sold in New Jersey be from solar electric power by 2021, lowers the solar alternative compliance payment amount starting in 2019 and requires the NJBPU to adopt rules to replace the current solar renewable energy credit program; and requires the NJBPU to increase its offshore wind energy credit program to 3,500 MW. The new legislation further imposes an energy efficiency standard that each electric public utility will be required to reduce annual usage by 2% and provides for utilities to annually file for recovery of the costs of the programs, including the revenue impact of sales losses resulting from the programs. The NJBPU is required to initiate a study to determine the savings targets for each public utility, to adopt other rules regarding the programs, and to approve energy efficiency and peak demand reduction programs for each utility. The new legislation also requires the NJBPU to conduct an energy storage analysis including the potential costs and benefits and to initiate a proceeding to establish a goal of achieving 2,000 MW of energy storage by 2030; requires the utilities to conduct a study on voltage optimization on their distribution system; and requires the NJBPU to establish a community solar program to permit customers to participate in a solar project that is not located on the customer's property.

On the same day, the Governor of New Jersey also signed new legislation, which became effective immediately, that will establish a ZEC program providing 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. PSEG's Salem nuclear plant is expected to apply for approval to participate in the ZEC program. Under the new 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. The NJBPU has 180 days from the effective date to establish procedures for implementation of the ZEC program and 330 days from the effective date to determine which nuclear power plants are selected to receive ZECs under the program. Selected nuclear plants will receive ZEC payments for each energy year (12-

month period from June 1 through May 31) within 90 days after the completion of such energy year. The quantity of ZECs issued will be determined based on the greater of 40% of the total number of MWh of electricity distributed by the public electric distribution utilities in New Jersey in the prior year, or the total number of MWh of electricity generated in the prior year by the selected nuclear power plants. The ZEC price is approximately $10 per MWh during the first 3-year eligibility period. For eligibility periods following the first 3-year eligibility period, the NJBPU has discretion to reduce the ZEC price. Electric distribution utilities in New Jersey, including ACE, will be authorized to collect from retail distribution customers through a non-bypassable charge all costs associated with the utility's procurement of the ZECs. On August 29, 2018, the NJBPU issued an order opening a proceeding in which stakeholders can provide input on implementation of the ZEC program. See Note 8 - Early Plant Retirements for additional information on New Jersey's ZEC program potential impacts to PSEG's Salem nuclear plant.

2018 New Jersey Electric Distribution Base Rates (Exelon, PHI and ACE). On June 15, 2018, ACE submitted an application with the NJBPU to increase its annual electric distribution base rates by $99.7 million (before New Jersey sales and use tax), based upon a requested ROE of 10.1%. Included in the $99.7 million request is $40 million of higher depreciation expense related to ACE's updated depreciation study. On July 25, 2018, the NJBPU dismissed ACE's base rate case due to the number of forecasted months included in the twelve month test period. Historically, ACE and other New Jersey utilities have filed distribution base rate cases with a similar number of forecasted months in the test period.

On August 21, 2018, ACE refiled its application with the NJBPU, requesting an increase to its electric distribution rates of $109 million (before New Jersey sales and use tax), reflecting a requested ROE of 10.1%. Included in the $109 million request is $40 million of higher depreciation expense related to ACE's updated depreciation study. ACE currently expects a decision in this matter in the third quarter of 2019 but cannot predict if the NJBPU will approve the application as filed.

New York Regulatory Matters

New York Clean Energy Standard (Exelon and Generation). On August 1, 2016, the NYPSC issued an order establishing the New York CES, a component of which is a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually.

On October 19, 2016, a coalition of fossil-generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically, that the ZEC program interferes with FERC's jurisdiction over wholesale rates and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The State also filed a motion to dismiss. On July 25, 2017, the court granted both motions to dismiss. On August 24, 2017, the plaintiff appealed the decision to the U.S. Court of Appeals for the Second Circuit. On September 27, 2018, the U.S. Court of Appeals for the Second Circuit affirmed the lower court's dismissal of the complaint against the ZEC program.

In addition, on November 30, 2016, a group of parties, including certain environmental groups and individuals, filed a Petition in New York State court seeking to invalidate the ZEC program. The Petition, which was amended on January 13, 2017, argued that the NYPSC did not have authority to establish the program, that it violated state environmental law and that it violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program. On February 15, 2017, Generation and CENG filed a motion to dismiss the state court action. The NYPSC also filed a motion to dismiss the state court action. On March 24, 2017, the plaintiffs filed a memorandum of law opposing the motions to dismiss, and Generation and CENG filed a reply brief on April 28, 2017. Oral

argument was held on June 19, 2017. On January 22, 2018, the court dismissed the environmental claims and the majority of the plaintiffs from the case but denied the motions to dismiss with respect to the remaining five plaintiffs and claims, without commenting on the merits of the case. The case is now proceeding to summary judgment with the full record. Exelon's and the state's answers and briefs were filed on March 30, 2018. Plaintiffs' responses were due on May 11, 2018; however, on April 17, 2018, the plaintiffs filed an order to show cause seeking production of additional documents, including confidential financial information. Exelon and the state filed in opposition to the order to show cause. On July 18, 2018, the court denied the order to show cause and ordered the parties to provide the court with an agreed upon final schedule for the remaining brief. Negotiations over the schedule for the remaining briefing have not yet been finalized. After briefing is completed, the court will decide whether or not to set the case for hearing.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 8 — Early Plant Retirements for additional information related to Ginna and Nine Mile Point.

Federal Regulatory Matters

Tax Cuts and Jobs Act and Transmission-Related Income Tax Regulatory Assets (Exelon and the Utility Registrants). Pursuant to their respective transmission formula rates, ComEd, PECO, BGE, Pepco, DPL and ACE began passing back to customers on June 1, 2018, the benefit of lower income tax rates effective January 1, 2018. ComEd's, BGE's, Pepco's, DPL's and ACE's transmission formula rates currently do not provide for the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA.

On December 13, 2016 (and as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. ComEd, Pepco, DPL and ACE had similar transmission-related income tax regulatory liabilities and assets also requiring FERC approval. On November 16, 2017, FERC issued an order rejecting BGE's proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. FERC's rejection order focused on the lack of timeliness of BGE's request to recover amounts that would have been previously amortized but indicated that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement. Based on FERC's order, management of each company concluded that the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery was no longer probable of recovery. As a result, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE recorded charges to Income tax expense within their Consolidated Statements of Operations and Comprehensive Income in the fourth quarter of 2017, reducing their associated transmission-related income tax regulatory assets. Similar regulatory assets and liabilities at PECO are not subject to the same FERC transmission rate recovery formula and, thus, are not impacted by BGE's November 16, 2017 FERC order. See below for additional information regarding PECO's transmission formula rate filing.

On December 18, 2017, BGE filed for clarification and rehearing of FERC's order, still seeking full recovery of its existing transmission-related income tax regulatory asset amounts, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. On February 27, 2018 (and updated on March 26, 2018), BGE submitted a letter to FERC advising that the lower federal corporate income tax rate effective January 1, 2018 provided for in TCJA will be reflected in BGE's annual formula rate update effective June 1, 2018, but that the deferred income tax benefits will not be passed back to customers unless BGE's formula rate is revised to provide for pass back and recovery of transmission-related income tax-related regulatory liabilities and assets.

On February 23, 2018 (and as amended on July 9, 2018), ComEd, Pepco, DPL, and ACE each filed with FERC to revise their transmission formula rate mechanisms to facilitate passing back to customers ongoing annual TCJA tax savings and to permit recovery of transmission-related income tax regulatory assets, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery.

On September 7, 2018, FERC issued orders rejecting BGE’s December 18, 2017 request for rehearing and clarification and ComEd's, Pepco's, DPL's and ACE's February 23, 2018 (as amended on July 9, 2018) filings, again citing the lack of timeliness of the requests to recover amounts that would have been previously amortized, but indicating that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement. The orders did not address the remittance of TCJA transmission-related income tax regulatory liabilities, but rather referenced FERC’s separate Notice of Inquiry of such amounts issued on March 15, 2018.

On October 1, 2018, ComEd, BGE, Pepco, DPL, and ACE submitted new filings to recover ongoing non-TCJA amortization amounts and refund TCJA transmission-related income tax regulatory liabilities for the prospective period starting on October 1, 2018 but cannot predict the outcome of these FERC proceedings. If FERC ultimately rules that the future, ongoing non-TCJA amortization amounts are not recoverable, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately $73 million, $51 million, $13 million, $9 million, $3 million, $5 million and $1 million, respectively, as of September 30, 2018.

On October 9, 2018, ComEd, Pepco, DPL, and ACE sought rehearing of FERC's September 7, 2018 order, still seeking full recovery of their existing transmission-related income tax regulatory asset amounts, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. ComEd, Pepco, DPL, and ACE cannot predict the outcome of this rehearing request. BGE has 60 days from the FERC September 7, 2018 order to file a petition for review in the federal court of appeals.

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Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). The following total (decreases)/increases were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2018 annual electric transmission formula rate updates.

2018 Annual Transmission Updates[a][b]	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement (decrease) increase	$(44)	$10	$6	$14	$4
Annual reconciliation increase (decrease)	18	4	2	13	(4)
Dedicated facilities increase[c]	—	12	—	—	—
Total revenue requirement (decrease) increase	$(26)	$26	$8	$27	$—
Allowed return on rate base[d]	8.32 %	7.61%	7.82%	7.29%	8.02%
Allowed ROE[e]	11.50%	10.50%	10.50%	10.50%	10.50%

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(a) All rates are effective June 2018, subject to review by the FERC and other parties, which is due by fourth quarter 2018.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion above.

(c) BGE's transmission revenues include a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to a specifically designated load by BGE.

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

(e) As part of the FERC-approved settlement of ComEd’s 2007 transmission rate case, the rate of return on common equity is 11.50% 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%. 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 regional transmission organization.

See Note 3 - Regulatory Matters of the Exelon 2017 Form 10-K for additional information regarding transmission formula rate updates.

Transmission Formula Rate (Exelon and PECO). On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the final outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

PJM Transmission Rate Design (All Registrants). On June 15, 2016, a number of parties, including the Utility Registrants, filed a proposed settlement with FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. The settlement included provisions for monthly credits or charges related

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to the periods prior to January 1, 2016 that are expected to be refunded or recovered through PJM wholesale transmission rates through December 2025.

On May 31, 2018, FERC issued an order approving the settlement and directed PJM to adjust wholesale transmission rates within 30 days. Pursuant to the order, similar charges for the period January 1, 2016 through June 30, 2018 will also be refunded or recovered through PJM wholesale transmission rates over the subsequent 12-month period. PJM commenced billing the refunds and charges associated with this settlement in August 2018. The Utility Registrants expect to refund or recover these settlement amounts through prospective electric distribution customer rates. On July 2, 2018, a number of parties filed petitions for rehearing or clarification.

Pursuant to the FERC approval of the settlement and the expected refund or recovery of the associated amounts from electric distribution customers, in the second quarter of 2018 and as adjusted in the third quarter of 2018, the Utility Registrants recorded the following payables to/receivables from PJM and related regulatory assets/liabilities. Generation recorded a $41 million net payable to PJM and a pre-tax charge within Purchased power and fuel expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

	PJM Receivable	PJM Payable	Regulatory Asset	Regulatory Liability
Exelon	$ 220	$ 176	$ 136	$ 221
Generation	—	41	—	—
ComEd	122	—	—	122
PECO	85	—	—	85
BGE	—	51	51	—
PHI[(a)]	13	84	85	14
Pepco	—	84	84	—
DPL	10	—	—	10
ACE	3	—	1	4

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(a) PHI reflects the consolidated impacts of Pepco, DPL, and ACE.

Operating License Renewals (Exelon and Generation). On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year 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) with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment.

On April 21, 2016, Generation and the U.S. Fish and Wildlife Service of the U.S. Department of the Interior executed a Settlement Agreement resolving all fish passage issues between the parties. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license.

On April 27, 2018, the MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contains numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage, which could have a material, unfavorable impact on Exelon’s and Generation’s results of operations, cash flows and financial positions through an increase in capital expenditures and operating costs if implemented. On May 25, 2018, Generation filed complaints in federal and state court, along with a petition for reconsideration with MDE, alleging that the conditions are unfair and onerous violating MDE regulations, state, federal, and constitutional law. Generation also requested that FERC defer action on the federal license while these significant state and federal law issues are pending. On July 9, 2018, MDE filed a motion to dismiss Generation's complaint in state court, which was granted without prejudice on October 9, 2018. The court found MDE's Certification was not a "final decision" of Exelon's rights and that because Exelon's motion for reconsideration remains pending, as does its administrative appeal of the 401 Certification, there was no final administrative decision for the court to review at this time. Exelon continues to challenge the 401 Certification through the administrative process and in federal court. Exelon and Generation cannot predict the final outcome or its financial impact, if any, on Exelon or Generation.

As of September 30, 2018, $35 million of direct costs associated with Conowingo licensing efforts have been capitalized. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on Generation's operating license renewal efforts.

On July 10, 2018, Generation submitted a second 20-year license renewal application with the NRC for Peach Bottom Units 2 and 3. Generation anticipates the second license renewal process to take approximately 2 years from the application submission until completion of the NRC’s review process. Peach Bottom Units 2 and 3 are licensed to operate through 2033 and 2034, respectively.

Regulatory Assets and Liabilities (Exelon and the Utility Registrants)

Exelon and the Utility Registrants each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

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The following tables provide information about the regulatory assets and liabilities of Exelon and the Utility Registrants as of September 30, 2018 and December 31, 2017. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on the specific regulatory assets and liabilities.

September 30, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits[a]	$3,710	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes	391	—	381	—	10	10	—	—
AMI programs[c]	583	142	27	198	216	144	72	—
Electric distribution formula rate[d]	228	228	—	—	—	—	—	—
Energy efficiency costs	357	357	—	—	—	—	—	—
Debt costs	102	34	1	11	68	15	7	6
Fair value of long-term debt	716	—	—	—	581	—	—	—
Fair value of PHI's unamortized energy contracts	600	—	—	—	600	—	—	—
Asset retirement obligations	114	76	22	15	1	1	—	—
MGP remediation costs	318	299	19	—	—	—	—	—
Under-recovered uncollectible accounts	71	71	—	—	—	—	—	—
Renewable energy	260	259	—	—	1	—	—	1
Energy and transmission programs[e][f][g][h][i][j]	251	7	50	72	122	93	15	14
Deferred storm costs	45	—	—	—	45	11	5	29
Energy efficiency and demand response programs	561	—	2	291	268	194	74	—
Merger integration costs[k][l][m]	44	—	—	4	40	18	12	10
Under-recovered revenue decoupling[n]	64	—	—	—	64	64	—	—
COPCO acquisition adjustment	3	—	—	—	3	—	3	—
Workers compensation and long-term disability costs	36	—	—	—	36	36	—	—
Vacation accrual	24	—	11	—	13	—	8	5
Securitized stranded costs	57	—	—	—	57	—	—	57
CAP arrearage	10	—	10	—	—	—	—	—
Removal costs	555	—	—	—	555	156	97	302
DC PLUG charge	168	—	—	—	168	168	—	—
Other	74	12	9	6	47	36	8	3
Total regulatory assets	9,342	1,485	532	597	2,895	946	301	427
Less: current portion	1,340	256	84	195	521	284	66	44
Total noncurrent regulatory assets	$8,002	$1,229	$448	$402	$2,374	$662	$235	$383

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September 30, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$20	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes[b]	5,054	2,418	—	1,015	1,621	734	493	394
Nuclear decommissioning	2,958	2,469	489	—	—	—	—	—
Removal costs	1,566	1,370	—	67	129	20	109	—
Deferred rent	34	—	—	—	34	—	—	—
Energy efficiency and demand response programs	10	3	5	—	2	—	—	2
DLC program costs	7	—	7	—	—	—	—	—
Electric distribution tax repairs	10	—	10	—	—	—	—	—
Gas distribution tax repairs	4	—	4	—	—	—	—	—
Energy and transmission programs[e][f][g][h][i][j]	372	204	143	7	18	—	14	4
Over-recovered revenue decoupling[n]	21	—	—	17	4	—	4	—
Renewable portfolio standards costs	140	140	—	—	—	—	—	—
Zero emission credit costs	18	18	—	—	—	—	—	—
Over-recovered uncollectible accounts	2	—	—	—	2	—	—	2
Merger integration costs[l]	3	—	—	—	3	—	3	—
TCJA income tax benefit over-recoveries[o]	108	—	61	19	28	6	8	14
Other	118	16	21	40	41	4	23	12
Total regulatory liabilities	10,445	6,638	740	1,165	1,882	764	654	428
Less: current portion	689	320	159	95	99	5	67	27
Total noncurrent regulatory liabilities	$9,756	$6,318	$581	$1,070	$1,783	$759	$587	$401

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December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits[(a)]	$3,848	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes	306	—	297	—	9	9	—	—
AMI programs[(c)]	640	155	36	214	235	158	77	—
Electric distribution formula rate[(d)]	244	244	—	—	—	—	—	—
Energy efficiency costs	166	166	—	—	—	—	—	—
Debt costs	116	37	1	11	73	15	8	5
Fair value of long-term debt	758	—	—	—	619	—	—	—
Fair value of PHI's unamortized energy contracts	750	—	—	—	750	—	—	—
Asset retirement obligations	109	73	22	14	—	—	—	—
MGP remediation costs	295	273	22	—	—	—	—	—
Under-recovered uncollectible accounts	61	61	—	—	—	—	—	—
Renewable energy	258	256	—	—	2	—	1	1
Energy and transmission programs[(e)(g)(h)(i)(j)]	82	6	1	23	52	11	15	26
Deferred storm costs	27	—	—	—	27	7	5	15
Energy efficiency and demand response programs	596	—	1	285	310	229	81	—
Merger integration costs[(k)(l)(m)]	45	—	—	6	39	20	10	9
Under-recovered revenue decoupling[(n)]	55	—	—	14	41	38	3	—
COPCO acquisition adjustment	5	—	—	—	5	—	5	—
Workers compensation and long-term disability costs	35	—	—	—	35	35	—	—
Vacation accrual	19	—	6	—	13	—	8	5
Securitized stranded costs	79	—	—	—	79	—	—	79
CAP arrearage	8	—	8	—	—	—	—	—
Removal costs	529	—	—	—	529	150	93	286
DC PLUG charge	190	—	—	—	190	190	—	—
Other	67	8	16	4	39	29	8	4
Total regulatory assets	9,288	1,279	410	571	3,047	891	314	430
Less: current portion	1,267	225	29	174	554	213	69	71
Total noncurrent regulatory assets	$8,021	$1,054	$381	$397	$2,493	$678	$245	$359

December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$30	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes[(b)]	5,241	2,479	—	1,032	1,730	809	510	411
Nuclear decommissioning	3,064	2,528	536	—	—	—	—	—
Removal costs	1,573	1,338	—	105	130	20	110	—
Deferred rent	36	—	—	—	36	—	—	—
Energy efficiency and demand response programs	23	4	19	—	—	—	—	—
DLC program costs	7	—	7	—	—	—	—	—
Electric distribution tax repairs	35	—	35	—	—	—	—	—
Gas distribution tax repairs	9	—	9	—	—	—	—	—
Energy and transmission programs[(e)(f)(i)(j)]	111	47	60	—	4	—	1	3
Renewable portfolio standard costs	63	63	—	—	—	—	—	—
Zero emission credit costs	112	112	—	—	—	—	—	—
Over-recovered uncollectible accounts	2	—	—	—	2	—	—	2
Other	82	6	24	26	26	3	14	6

Total regulatory liabilities	10,388	6,577	690	1,163	1,928	832	635	422
Less: current portion	523	249	141	62	56	3	42	11
Total noncurrent regulatory liabilities	$9,865	$6,328	$ 549	$1,101	$1,872	$ 829	$593	$411

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(a) Includes regulatory assets established at the Constellation and PHI merger dates of $401 million and $897 million, respectively, as of September 30, 2018 and $440 million and $953 million, respectively, as of December 31, 2017 related to the rate regulated portions of the deferred costs associated with legacy Constellation's and PHI's pension and other postretirement benefit plans that are being amortized and recovered over approximately 12 years and 3 to 15 years, respectively (as established at the respective acquisition dates). The Utility Registrants are not earning or paying a return on these amounts.

(b) As of September 30, 2018, includes transmission-related income tax regulatory liabilities that require FERC approval separate from the transmission formula rate of $464 million, $135 million, $136 million, $145 million and $141 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2017, includes transmission-related income tax regulatory liabilities that require FERC approval separate from the transmission formula rate of $484 million, $137 million, $147 million, $148 million and $147 million for ComEd, BGE, Pepco, DPL and ACE, respectively.

(c) As of September 30, 2018, BGE's regulatory asset of $198 million includes $117 million of unamortized incremental deployment costs under the program, $48 million of unamortized costs of the non-AMI meters replaced under the AMI program, and $33 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. As of December 31, 2017, BGE's regulatory asset of $214 million includes $129 million of unamortized incremental deployment costs under the program, $53 million of unamortized costs of the non-AMI meters replaced under the AMI program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. Recovery of the post-test year incremental deployment costs will be addressed in a future base rate proceeding.

(d) As of September 30, 2018, ComEd's regulatory asset of $228 million was comprised of $165 million for the 2016, 2017 and 2018 annual reconciliations and $63 million related to significant one-time events. As of December 31, 2017, ComEd's regulatory asset of $244 million was comprised of $186 million for the 2016 and 2017 annual reconciliations and $58 million related to significant one-time events.

(e) As of September 30, 2018, ComEd's regulatory asset of $7 million represents transmission costs recoverable through its FERC approved formula rate. As of September 30, 2018, ComEd's regulatory liability of $204 million included $101 million related to the PJM Transmission Rate Design Settlement, $72 million related to over-recovered energy costs and $31 million associated with revenues received for renewable energy requirements. As of December 31, 2017, ComEd's regulatory asset of $6 million represents transmission costs recoverable through its FERC approved formula rate. As of December 31, 2017, ComEd's regulatory liability of $47 million included $14 million related to over-recovered energy costs and $33 million associated with revenues received for renewable energy requirements.

(f) As of September 30, 2018, PECO's regulatory asset of $50 million represents the under-recovered natural gas costs under the PGC. As of December 31, 2017, PECO's regulatory asset of $1 million is related to under-recovered costs under the TSC program. As of September 30, 2018, PECO's regulatory liability of $143 million included $85 million related to the PJM Transmission Rate Design Settlement, $43 million related to over-recovered costs under the DSP program, $3 million related to the over-recovered transmission service charges and $12 million related to over-recovered non-bypassable transmission service charges. As of December 31, 2017, PECO's regulatory liability of $60 million included $36 million related to over-recovered costs under the DSP program, $12 million related to over-recovered non-bypassable transmission service charges and $12 million related to the over-recovered natural gas costs under the PGC.

(g) As of September 30, 2018, BGE's regulatory asset of $72 million included $48 million related to the PJM Transmission Rate Design Settlement, $14 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $7 million related to under-recovered electric energy costs and $3 million of abandonment costs to be recovered upon FERC approval. As of September 30, 2018, BGE's regulatory liability of

$7 million related to over-recovered natural gas costs. As of December 31, 2017, BGE’s regulatory asset of $23 million included $7 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $5 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval and $8 million of under-recovered natural gas costs.

(h) As of September 30, 2018, Pepco's regulatory asset of $93 million included $74 million related to the PJM Transmission Rate Design Settlement, $7 million of transmission costs recoverable through its FERC approved formula rate and $12 million related to under-recovered electric energy costs. As of December 31, 2017, Pepco's regulatory asset of $11 million included $3 million of transmission costs recoverable through its FERC approved formula rate and $8 million of under-recovered electric energy costs.

(i) As of September 30, 2018, DPL's regulatory asset of $15 million included $14 million of transmission costs recoverable through its FERC approved formula rate and $1 million related to under-recovered electric energy costs. As of September 30, 2018, DPL's regulatory liability of $14 million included $10 million related to the PJM Transmission Rate Design Settlement and $4 million related to over-recovered electric energy and gas fuel costs. As of December 31, 2017, DPL's regulatory asset of $15 million included $8 million of transmission costs recoverable through its FERC approved formula rate and $7 million related to under-recovered electric energy costs. As of December 31, 2017, DPL's regulatory liability of $1 million related to over-recovered electric energy costs.

(j) As of September 30, 2018, ACE's regulatory asset of $14 million included $7 million of transmission costs recoverable through its FERC approved formula rate and $7 million of under-recovered electric energy costs. As of September 30, 2018, ACE's regulatory liability of $4 million included $3 million related to the PJM Transmission Rate Design Settlement and $1 million related to over-recovered electric energy costs. As of December 31, 2017, ACE's regulatory asset of $26 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $15 million of under-recovered electric energy costs. As of December 31, 2017, ACE's regulatory liability of $3 million related to over-recovered electric energy costs.

(k) As of September 30, 2018, Pepco’s regulatory asset of $18 million represents previously incurred PHI integration costs, including $9 million authorized for recovery in Maryland and $9 million expected to be recovered in the District of Columbia service territory. As of December 31, 2017, Pepco’s regulatory asset of $20 million represents previously incurred PHI integration costs, including $11 million authorized for recovery in Maryland and $9 million expected to be recovered in the District of Columbia service territory.

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(l) As of September 30, 2018, DPL's regulatory asset of $12 million represents previously incurred PHI integration costs, including $4 million authorized for recovery in Maryland, $5 million authorized for recovery in Delaware electric rates, $2 million authorized for recovery in Delaware gas rates and $1 million expected to be recovered in electric rates in the Delaware and Maryland service territories. As of September 30, 2018, DPL's regulatory liability of $3 million represents net synergy savings incurred related to PHI integration costs that are expected to be returned in electric and gas rates in the Delaware service territory. As of December 31, 2017, DPL's regulatory asset of $10 million represents previously incurred PHI integration costs, including $4 million authorized for recovery in Maryland, $5 million authorized for recovery in Delaware electric rates, and $1 million expected to be recovered in electric and gas rates in the Maryland and Delaware service territories.

(m) As of September 30, 2018 and December 31, 2017, ACE's regulatory asset of $10 million and $9 million, respectively, represents previously incurred PHI integration costs expected to be recovered in the New Jersey service territory.

(n) Represents the electric and natural gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of September 30, 2018, BGE had a regulatory asset of less than $1 million related to under-recovered electric revenue decoupling and a regulatory liability of $17 million related to over-recovered natural gas revenue decoupling. As of December 31, 2017, BGE had a regulatory asset of $10 million related to under-recovered electric revenue decoupling and $4 million related to under-recovered natural gas revenue decoupling.

(o) Represents over-recoveries related to the change in the federal income tax rate with the enactment of the TCJA. These regulatory liabilities will be amortized as the TCJA income tax benefits are passed back to customers. See Tax Cuts and Jobs Act disclosures above for additional information on the regulatory proceedings.

Capitalized Ratemaking Amounts Not Recognized (Exelon and the Utility Registrants)

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes on 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 our customers.

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
September 30, 2018	$ 67	$ 8	$ —	$ 50	$ 9	$ 5	$ 4	$ —

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
December 31, 2017	$ 69	$ 6	$ —	$ 53	$ 10	$ 6	$ 4	$ —

(a) Reflects ComEd's unrecognized equity returns earned 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.

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Purchase of Receivables Programs (Exelon and the Utility Registrants)
ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon and the Utility Registrants do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon’s and the Utility Registrant's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of September 30, 2018 and December 31, 2017.

As of September 30, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 379	$ 120	$ 91	$ 60	$ 108	$ 69	$ 11	$ 28
Allowance for uncollectible accounts[(a)]	(37)	(19)	(5)	(3)	(10)	(5)	(1)	(4)
Purchased receivables, net	$ 342	$ 101	$ 86	$ 57	$ 98	$ 64	$ 10	$ 24

As of December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 298	$ 87	$ 70	$ 58	$ 83	$ 56	$ 9	$ 18
Allowance for uncollectible accounts[(a)]	(31)	(14)	(5)	(3)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 267	$ 73	$ 65	$ 55	$ 74	$ 51	$ 8	$ 15

(a) For ComEd, BGE, Pepco and DPL, reflects the incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing tariff.

7. Impairment of Long-Lived Assets (Exelon and Generation)
Registrants evaluate long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 2018, updates to Exelon's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than its carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived merchant wind assets held and used with a net carrying amount of $41 million were fully impaired and a pre-tax impairment charge of $41 million was recorded during the second quarter of 2018 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.
During the first quarter of 2018, Mystic Unit 9 did not clear in the ISO-NE capacity auction for the 2021 - 2022 planning year. On March 29, 2018, Generation announced it had formally notified ISO-NE of the early retirement of its Mystic Generating Station's Units 7, 8, 9 and the Mystic Jet Unit (Mystic Generating Station assets) absent regulatory reforms. These events suggested that the carrying value of its New England asset group may be impaired. As a result, Generation completed a comprehensive

review of the estimated undiscounted future cash flows of the New England asset group and no impairment charge was required. Further developments such as the failure of ISO-NE to adopt interim and long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group, which could be material. See Note 8 — Early Plant Retirements for additional information on the early retirement of the Mystic Generating Station assets.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP's assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a pre-tax impairment charge of $460 million within Operating and maintenance expense on their Consolidated Statements of Operations and Comprehensive Income of which $418 million was recorded in the second quarter of 2017. On November 7, 2017, EGTP and its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware and, as a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements. See Note 4 — Mergers, Acquisitions and Dispositions for additional information.

8. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation’s plants. Factors that will continue to affect the economic value of Generation’s plants include, but are 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 decommissioning trust 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.

In 2015 and 2016, Generation identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York and Three Mile Island nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors.

Assuming the continued effectiveness of the Illinois ZES and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these nuclear plants could again be at heightened risk for early retirement, which could have a material impact on Exelon’s and Generation’s future results of operations, cash flows and financial positions. See Note 6 — Regulatory Matters for additional information on the Illinois ZES and New York CES.

In Pennsylvania, the TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, the third consecutive year that TMI failed to clear the PJM base residual capacity auction. The plant is currently committed to operate through May 2019 and is licensed to operate through 2034. On May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified

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Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.
On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek nuclear plant at the end of its current operating cycle in 2018. On September 17, 2018, Oyster Creek permanently ceased generation operations. In 2010, Generation announced that Oyster Creek would retire by the end of 2019 as part of an agreement with the State of New Jersey to avoid significant costs associated with the construction of cooling towers to meet the State's then new environmental regulations. Since then, like other nuclear sites, Oyster Creek has continued to face rising operating costs amid a historically low wholesale power price environment. The decision to retire Oyster Creek in 2018 at the end of its current operating cycle involved consideration of several factors, including economic and operating efficiencies, and avoids a refueling outage scheduled for the fall of 2018 that would have required advanced purchasing of fuel fabrication and materials beginning in late February 2018. Generation has filed the required market and regulatory notifications to shut down the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of Oyster Creek as proposed.
As a result of these early nuclear plant retirement decisions, Exelon and Generation recognized one-time charges in Operating and maintenance expense related to materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments, among other items. In addition to these one-time charges, annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. See Note 13 — Asset Retirement Obligations for additional information on changes to the nuclear decommissioning ARO balance.
During the three and nine months ended September 30, 2018, both Exelon's and Generation's results include a net incremental $174 million and $525 million, respectively, of total pre-tax expense associated with the early retirement decisions for TMI and Oyster Creek, as summarized in the table below.

Income statement expense (pre-tax)	Q3 2018	YTD 2018
Depreciation and amortization[(a)]		
Accelerated depreciation[(b)]	$ 152	$ 441
Accelerated nuclear fuel amortization	18	52
Operating and maintenance[(c)]	4	32
Total	$ 174	$ 525

(a) Reflects incremental accelerated depreciation and amortization for TMI and Oyster Creek for the three and nine months ended September 30, 2018. The Oyster Creek year-to-date amounts are from February 2, 2018 through September 17, 2018.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(c) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments. It does not include remeasurement of the Oyster Creek ARO. Refer to Note 13 - Asset Retirement Obligations for additional detail.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Exelon's and Generation's 2017 results included a net incremental $339 million of total pre-tax expense associated with the early retirement decision for TMI, as summarized in the table below.

Income statement expense (pre-tax)	Q2 2017	Q3 2017	Q4 2017	YTD 2017
Depreciation and amortization[(a)]				
Accelerated depreciation[(b)]	$ 35	$ 106	$ 109	$ 250
Accelerated nuclear fuel amortization	2	6	4	12
Operating and maintenance[(c)]	71	5	1	77
Total	$ 108	$ 117	$ 114	$ 339

(a) Reflects incremental charges for TMI including incremental accelerated depreciation and amortization from May 30, 2017 through December 31, 2017.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(c) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments.

In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options.

On May 23, 2018, the Governor of New Jersey signed new legislation, which became effective immediately, that will establish a ZEC program providing 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 new 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. The NJBPU has 180 days from the effective date to establish procedures for implementation of the ZEC program and 330 days from the effective date to determine which nuclear power plants are selected to receive ZECs under the program. Selected nuclear plants will receive ZEC payments for each energy year (12-month period from June 1 through May 31) within 90 days after the completion of such energy year. Assuming the successful implementation of the New Jersey ZEC program and the selection of Salem as one of the qualifying facilities, the New Jersey ZEC program has the potential to mitigate the heightened risk of earlier retirement for Salem. See Note 6 — Regulatory Matters for additional information on the New Jersey ZEC program.

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The following table provides the balance sheet amounts as of September 30, 2018 for Generation's ownership share of the significant assets and liabilities associated with Salem that would potentially be impacted by a decision to permanently cease generation operations.

	September 30, 2018
Asset Balances	
Materials and supplies inventory	$ 45
Nuclear fuel inventory, net	114
Completed plant, net	605
Construction work in progress	34
Liability Balances	
Asset retirement obligation	(455)
NRC License Renewal Term	2036 (unit 1) 2040 (unit 2)

On March 29, 2018, Generation announced it had formally notified grid operator ISO-NE of its plans to early retire its Mystic Generating Station assets absent regulatory reforms on June 1, 2022, at the end of the current capacity commitment for Mystic Units 7 and 8. Mystic Unit 9 is currently committed through May 2021. Absent any regulatory reforms to properly value reliability and regional fuel security, these units will not participate in the Forward Capacity Auction (FCA) scheduled for February 2019 for the 2022 - 2023 capacity commitment period.
The ISO-NE announced that it would take a three-step approach to fuel security. First, on May 1, 2018, ISO-NE made a filing with FERC requesting waiver of certain tariff provisions to allow it to retain Mystic Units 8 and 9 for fuel security for the 2022 - 2024 capacity commitment periods. Second, ISO-NE planned to file tariff revisions to allow it to retain other resources for fuel security in the capacity market if necessary in the future. Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE's January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic Units 8 and 9, cannot recover future operating costs, including the cost of procuring fuel.
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 and 9 for the period between June 1, 2022 - May 31, 2024. Among the costs included in the filing are costs associated with the Distrigas facility. Generation asked that FERC establish an expedited settlement process that would allow Generation to know the outcome of the cost-of-service proceeding prior to making a final decision as to whether to unconditionally retire the plants beginning June 1, 2022. A number of parties filed protests in response to the May 16, 2018 filing.
On July 2, 2018, FERC issued an order denying ISO-NE's May 1, 2018 waiver request on procedural grounds but accepting ISO-NE's conclusions that retirement of Mystic Units 8 and 9 could cause a violation of mandatory reliability standards as soon as 2022. Accordingly, FERC ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address demonstrated fuel security concerns and (ii) make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. FERC also extended the deadline by which Generation must make a retirement decision for Mystic Units 8 and 9 to January 4, 2019. In addition, notwithstanding its denial of the waiver request, FERC stated that it will continue to evaluate Mystic's May 16, 2018 cost-of-service agreement filing. On August 31, 2018,

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ISO-NE filed a compliance filing in response to FERC's July 2, 2018 order proposing short-term tariff changes to permit it to retain a resource for fuel security reliability reasons. A number of parties, including Generation, have submitted comments on the proposal, which is pending before FERC.

On July 13, 2018, FERC issued an order accepting Generation’s cost-of-service agreement for filing and making findings on certain issues, including that recovery of fuel supply costs for the Distrigas facility are not prohibited if they are just and reasonable. Additionally, the order established hearing procedures on an expedited schedule. Any settlement discussions are to be undertaken on a parallel track with the hearing. Generation has requested that FERC issue an order by December 21, 2018, but FERC is not obligated to meet this date.

Exelon and Generation cannot predict the final outcome of these proceedings or the potential financial impact, if any, on Exelon or Generation.

The following table provides the balance sheet amounts as of September 30, 2018 for Generation’s significant assets and liabilities associated with the Mystic Generating Station assets that would potentially be impacted by a decision to permanently cease generation operations.

	September 30, 2018
Asset Balances	
Materials and supplies inventory	$ 21
Fuel inventory	18
Completed plant, net	877
Construction work in progress	5
Prepaid expenses[(a)]	15
Liability Balances	
Asset retirement obligation	(5)
Accrued expenses[(a)]	(2)

(a) Reflects ending balances only as they relate to Mystic's Long-term Service Agreement.

On October 1, 2018, Generation acquired the Distrigas liquefied natural gas import terminal to ensure the continued reliable supply of fuel to Mystic Units 8 and 9 while they remain operating.

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

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

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, 2018 and December 31, 2017:

Exelon

	September 30, 2018				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$834	$—	$834	$—	$834
Long-term debt (including amounts due within one year)[b][c]	35,290	—	33,608	2,079	35,687
Long-term debt to financing trusts[d]	390	—	—	411	411
SNF obligation	1,164	—	993	—	993

	December 31, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$929	$—	$929	$—	$929
Long-term debt (including amounts due within one year)[b][c]	34,264	—	34,735	1,970	36,705
Long-term debt to financing trusts[d]	389	—	—	431	431
SNF obligation	1,147	—	936	—	936

Generation

	September 30, 2018				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	$8,842	$—	$7,563	$1,461	$9,024
SNF obligation	1,164	—	993	—	993

	December 31, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$2	$—	$2	$—	$2
Long-term debt (including amounts due within one year)[b][c]	8,990	—	7,839	1,673	9,512
SNF obligation	1,147	—	936	—	936

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

ComEd

	September 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	8,100	—	8,317	—	8,317
Long-term debt to financing trusts[d]	205	—	—	214	214

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	$7,601	$ —	$8,418	$ —	$8,418
Long-term debt to financing trusts[d]	205	—	—	227	227

PECO

	September 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	3,083	—	3,130	50	3,180
Long-term debt to financing trusts	184	—	—	196	196

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	$2,903	$ —	$3,194	$ —	$3,194
Long-term debt to financing trusts	184	—	—	204	204

BGE

	September 30, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[b][c]	2,876	—	2,933	—	2,933

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$77	$ —	$ 77	$ —	$ 77
Long-term debt (including amounts due within one year)[b][c]	2,577	—	2,825	—	2,825

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PHI

	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
September 30, 2018					
Short-term liabilities[a]	$334	$—	$334	$—	$334
Long-term debt (including amounts due within one year)[b][c]	6,089	—	5,323	568	5,891
December 31, 2017					
Short-term liabilities[a]	$350	$—	$350	$—	$350
Long-term debt (including amounts due within one year)[b][c]	5,874	—	5,722	297	6,019

Pepco

	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
September 30, 2018					
Short-term liabilities[a]	$64	$—	$64	$—	$64
Long-term debt (including amounts due within one year)[b][c]	$2,625	$—	$2,890	$101	$2,991
December 31, 2017					
Short-term liabilities[a]	$26	$—	$26	$—	$26
Long-term debt (including amounts due within one year)[b][c]	2,540	—	3,114	9	3,123

DPL

	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
September 30, 2018					
Long-term debt (including amounts due within one year)[b][c]	$1,494	$—	$1,299	$196	$1,495
December 31, 2017					
Short-term liabilities[a]	$216	$—	$216	$—	$216
Long-term debt (including amounts due within one year)[b][c]	1,300	—	1,393	—	1,393

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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ACE

	September 30, 2018				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$270	$—	$270	$—	$270
Long-term debt (including amounts due within one year)[b][c]	1,100	—	887	271	1,158

	December 31, 2017				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$108	$—	$108	$—	$108
Long-term debt (including amounts due within one year)[b][c]	1,121	—	949	288	1,237

(a) Level 1 securities consist of dividends payable (included in other current liabilities). Level 2 securities consist of short term borrowings.

(b) Includes unamortized debt issuance costs which are not fair valued of $219 million, $53 million, $64 million, $23 million, $19 million, $11 million, $34 million, $12 million and $4 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of September 30, 2018. Includes unamortized debt issuance costs which are not fair valued of $201 million, $60 million, $52 million, $17 million, $17 million, $6 million, $32 million, $11 million and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2017.

(c) Level 2 securities consist of fixed-rate taxable debt securities, fixed-rate tax-exempt debt, variable rate tax-exempt debt and variable rate non-recourse debt. Level 3 securities consist of fixed-rate private placement taxable debt securities, fixed rate nonrecourse debt, government-backed fixed rate non-recourse debt and loan agreements.

(d) Includes unamortized debt issuance costs which are not fair valued of $1 million and $1 million for Exelon and ComEd, respectively, as of September 30, 2018 and December 31, 2017.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. 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.

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no material transfers between Level 1 and Level 2 during the nine months ended September 30, 2018 for cash equivalents, nuclear decommissioning trust fund investments, Pledged assets for Zion Station decommissioning, Rabbi trust investments, and Deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

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Generation and Exelon

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under "Not subject to leveling" in the table below.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation’s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2018 and December 31, 2017:

	Generation					Exelon				
As of September 30, 2018	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)]	$ 1,099	$ —	$ —	$ —	$ 1,099	$ 1,906	$ —	$ —	$ —	$ 1,906
NDT fund investments										
Cash equivalents[(b)]	278	92	—	—	370	278	92	—	—	370
Equities	3,206	1,608	1	1,942	6,757	3,206	1,608	1	1,942	6,757
Fixed income										
Corporate debt	—	1,629	231	—	1,860	—	1,629	231	—	1,860
U.S. Treasury and agencies	2,031	99	—	—	2,130	2,031	99	—	—	2,130
Foreign governments	—	49	—	—	49	—	49	—	—	49
State and municipal debt	—	165	—	—	165	—	165	—	—	165
Other[(c)]	—	29	—	854	883	—	29	—	854	883
Fixed income subtotal	2,031	1,971	231	854	5,087	2,031	1,971	231	854	5,087
Middle market lending	—	—	334	235	569	—	—	334	235	569
Private equity	—	—	—	303	303	—	—	—	303	303
Real estate	—	—	—	490	490	—	—	—	490	490
NDT fund investments subtotal[(d)]	5,515	3,671	566	3,824	13,576	5,515	3,671	566	3,824	13,576
Pledged assets for Zion Station decommissioning										
Cash equivalents	9	—	—	—	9	9	—	—	—	9
Pledged assets for Zion Station decommissioning subtotal[(e)]	9	—	—	—	9	9	—	—	—	9
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	48	—	—	—	48
Mutual funds	25	—	—	—	25	76	—	—	—	76
Fixed income	—	—	—	—	—	—	16	—	—	16
Life insurance contracts	—	23	—	—	23	—	73	37	—	110
Rabbi trust investments subtotal[(f)]	30	23	—	—	53	124	89	37	—	250

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	Generation					Exelon				
As of September 30, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Commodity derivative assets										
Economic hedges	234	2,117	2,019	—	4,370	234	2,117	2,019	—	4,370
Proprietary trading	—	84	90	—	174	—	84	90	—	174
Effect of netting and allocation of collateral[g][h]	(230)	(1,887)	(1,302)	—	(3,419)	(230)	(1,887)	(1,302)	—	(3,419)
Commodity derivative assets subtotal	4	314	807	—	1,125	4	314	807	—	1,125
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	—	—	—	—
Economic hedges	—	21	—	—	21	—	21	—	—	21
Effect of netting and allocation of collateral	—	(1)	—	—	(1)	—	(1)	—	—	(1)
Interest rate and foreign currency derivative assets subtotal	—	20	—	—	20	—	20	—	—	20
Other investments	—	—	52	—	52	—	—	52	—	52
Total assets	6,657	4,028	1,425	3,824	15,934	7,558	4,094	1,462	3,824	16,938
Liabilities										
Commodity derivative liabilities										
Economic hedges	(329)	(2,056)	(1,660)	—	(4,045)	(329)	(2,056)	(1,919)	—	(4,304)
Proprietary trading	—	(95)	(32)	—	(127)	—	(95)	(32)	—	(127)
Effect of netting and allocation of collateral[g][h]	247	1,987	1,397	—	3,631	247	1,987	1,397	—	3,631
Commodity derivative liabilities subtotal	(82)	(164)	(295)	—	(541)	(82)	(164)	(554)	—	(800)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	—	—	—	—	—	(10)	—	—	(10)
Economic hedges	—	(2)	—	—	(2)	—	(2)	—	—	(2)
Effect of netting and allocation of collateral	—	1	—	—	1	—	1	—	—	1
	—	(1)	—	—	(1)	—	(11)	—	—	(11)

Interest rate and foreign currency derivative liabilities subtotal										
Deferred compensation obligation	—	(36)	—	—	(36)	—	(142)	—	—	(142)
Total liabilities	(82)	(201)	(295)	—	(578)	(82)	(317)	(554)	—	(953)
Total net assets	$6,575	$3,827	$1,130	$3,824	$15,356	$7,476	$3,777	$908	$3,824	$15,985

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	Generation					Exelon				
As of December 31, 2017	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]	$ 168	$ —	$ —	$ —	$ 168	$ 656	$ —	$ —	$ —	$ 656
NDT fund investments										
Cash equivalents[b]	135	85	—	—	220	135	85	—	—	220
Equities	4,163	915	—	2,176	7,254	4,163	915	—	2,176	7,254
Fixed income										
Corporate debt	—	1,614	251	—	1,865	—	1,614	251	—	1,865
U.S. Treasury and agencies	1,917	52	—	—	1,969	1,917	52	—	—	1,969
Foreign governments	—	82	—	—	82	—	82	—	—	82
State and municipal debt	—	263	—	—	263	—	263	—	—	263
Other[c]	—	47	—	510	557	—	47	—	510	557
Fixed income subtotal	1,917	2,058	251	510	4,736	1,917	2,058	251	510	4,736
Middle market lending	—	—	397	131	528	—	—	397	131	528
Private equity	—	—	—	222	222	—	—	—	222	222
Real estate	—	—	—	471	471	—	—	—	471	471
NDT fund investments subtotal[d]	6,215	3,058	648	3,510	13,431	6,215	3,058	648	3,510	13,431
Pledged assets for Zion Station decommissioning										
Cash equivalents	2	—	—	—	2	2	—	—	—	2
Equities	—	1	—	—	1	—	1	—	—	1
Middle market lending	—	—	12	24	36	—	—	12	24	36
Pledged assets for Zion Station decommissioning subtotal[e]	2	1	12	24	39	2	1	12	24	39
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	77	—	—	—	77
Mutual funds	23	—	—	—	23	58	—	—	—	58
Fixed income	—	—	—	—	—	—	12	—	—	12
Life insurance contracts	—	22	—	—	22	—	71	22	—	93
Rabbi trust investments subtotal[f]	28	22	—	—	50	135	83	22	—	240
Commodity derivative assets										
Economic hedges	557	2,378	1,290	—	4,225	557	2,378	1,290	—	4,225
Proprietary trading	2	31	35	—	68	2	31	35	—	68
Effect of netting and allocation of collateral[g] [h]	(585)	(1,769)	(635)	—	(2,989)	(585)	(1,769)	(635)	—	(2,989)
Commodity derivative assets subtotal	(26)	640	690	—	1,304	(26)	640	690	—	1,304

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	3	—	—	3	—	6	—	—	6
Economic hedges	—	10	—	—	10	—	10	—	—	10
Effect of netting and allocation of collateral	(2)	(5)	—	—	(7)	(2)	(5)	—	—	(7)
Interest rate and foreign currency derivative assets subtotal	(2)	8	—	—	6	(2)	11	—	—	9
Other investments	—	—	37	—	37	—	—	37	—	37
Total assets	6,385	3,729	1,387	3,534	15,035	6,980	3,793	1,409	3,534	15,716
Liabilities										
Commodity derivative liabilities										
Economic hedges	(712)	(2,226)	(845)	—	(3,783)	(713)	(2,226)	(1,101)	—	(4,040)
Proprietary trading	(2)	(42)	(9)	—	(53)	(2)	(42)	(9)	—	(53)
Effect of netting and allocation of collateral[(g) (h)]	650	2,089	716	—	3,455	651	2,089	716	—	3,456
Commodity derivative liabilities subtotal	(64)	(179)	(138)	—	(381)	(64)	(179)	(394)	—	(637)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(2)	—	—	(2)	—	(2)	—	—	(2)
Economic hedges	(1)	(8)	—	—	(9)	(1)	(8)	—	—	(9)
Effect of netting and allocation of collateral	2	5	—	—	7	2	5	—	—	7
Interest rate and foreign currency derivative liabilities subtotal	1	(5)	—	—	(4)	1	(5)	—	—	(4)
Deferred compensation obligation	—	(38)	—	—	(38)	—	(145)	—	—	(145)
Total liabilities	(63)	(222)	(138)	—	(423)	(63)	(329)	(394)	—	(786)
Total net assets	$6,322	$3,507	$1,249	$3,534	$14,612	$6,917	$3,464	$1,015	$3,534	$14,930

(a) Generation excludes cash of $183 million and $259 million at September 30, 2018 and December 31, 2017 and restricted cash of $57 million and $127 million at September 30, 2018 and December 31, 2017. Exelon excludes cash of $330 million and $389 million at September 30, 2018 and December 31, 2017 and restricted cash of $85 million and $145 million at September 30, 2018 and December 31, 2017 and includes long-term restricted cash of $163 million and $85 million at September 30, 2018 and December 31, 2017, which is reported in Other deferred debits on the Consolidated Balance Sheets.

(b) Includes $37 million and $77 million of cash received from outstanding repurchase agreements at September 30, 2018 and December 31, 2017, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $(4) million and less than $1 million, which have a total notional amount of $915 million and $811 million at September 30, 2018 and December 31, 2017, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of Exelon and Generation's exposure to credit or market loss.

(d) Excludes net liabilities of $89 million and $82 million at September 30, 2018 and December 31, 2017, 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.

(e) Excludes net assets of less than $1 million at September 30, 2018. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

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

(f) The amount of unrealized gains/(losses) at Generation totaled less than $1 million for the three months ended September 30, 2018 and September 30, 2017. The amount of unrealized gains/(losses) at Generation totaled less than $1 million and $1 million for the nine months ended September 30, 2018 and September 30, 2017, respectively. The amount of unrealized gains/(losses) at Exelon totaled $1 million for the three months ended September 30, 2018 and September 30, 2017. The amount of unrealized gains/(losses) at Exelon totaled $2 million and $3 million for the nine months ended September 30, 2018 and September 30, 2017, respectively.

(g) Collateral posted/(received) from counterparties totaled $18 million, $100 million and $94 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2018. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $65 million, $320 million and $81 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2017.

(h) Of the collateral posted/(received), $(166) million represents variation margin on the exchanges as of September 30, 2018. Of the collateral posted/(received), $(117) million represents variation margin on the exchanges as of December 31, 2017.

Exelon and Generation hold investments without readily determinable fair values with carrying amounts of $71 million as of September 30, 2018. Changes were immaterial in fair value, cumulative adjustments and impairments for the three and nine months ended September 30, 2018.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on ComEd's, PECO's and BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2018 and December 31, 2017:

	ComEd				PECO				BGE			
As of September 30, 2018	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]	$211	$ —	$—	$211	$84	$ —	$ —	$84	$100	$ —	$ —	$100
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	11	—	11	—	—	—	—
Rabbi trust investments subtotal[b]	—	—	—	—	7	11	—	18	6	—	—	6
Total assets	211	—	—	211	91	11	—	102	106	—	—	106
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(10)	—	(10)	—	(5)	—	(5)
Mark-to-market derivative liabilities[c]	—	—	(259)	(259)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(259)	(266)	—	(10)	—	(10)	—	(5)	—	(5)
Total net assets (liabilities)	$211	$ (7)	$(259)	$(55)	$91	$ 1	$ —	$92	$106	$ (5)	$ —	$101

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	ComEd				PECO				BGE			
As of December 31, 2017	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)]	$98	$ —	$—	$98	$228	$ —	$ —	$228	$—	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[(b)]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	98	—	—	98	235	10	—	245	6	—	—	6
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(5)	—	(5)
Mark-to-market derivative liabilities[(c)]	—	—	(256)	(256)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(256)	(264)	—	(11)	—	(11)	—	(5)	—	(5)
Total net assets (liabilities)	$98	$ (8)	$(256)	$(166)	$235	$ (1)	$ —	$234	$6	$ (5)	$ —	$ 1

(a) ComEd excludes cash of $69 million and $45 million at September 30, 2018 and December 31, 2017 and includes long-term restricted cash of $144 million and $62 million at September 30, 2018 and December 31, 2017, which is reported in Other deferred debits on the Consolidated Balance Sheets. PECO excludes cash of $23 million and $47 million at September 30, 2018 and December 31, 2017. BGE excludes cash of $13 million and $17 million at September 30, 2018 and December 31, 2017 and restricted cash of $3 million and $1 million at September 30, 2018 and December 31, 2017.

(b) The amount of unrealized gains/(losses) at ComEd, PECO and BGE totaled less than $1 million for the three and nine months ended September 30, 2018 and September 30, 2017, respectively.

(c) The Level 3 balance consists of the current and noncurrent liability of $24 million and $235 million, respectively, at September 30, 2018, and $21 million and $235 million, respectively, at December 31, 2017, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2018 and December 31, 2017:

	As of September 30, 2018				As of December 31, 2017			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$182	$ —	$ —	$182	$83	$ —	$ —	$83
Rabbi trust investments								
Cash equivalents	42	—	—	42	72	—	—	72
Mutual funds	15	—	—	15	—	—	—	—
Fixed income	—	16	—	16	—	12	—	12
Life insurance contracts	—	22	37	59	—	23	22	45
Rabbi trust investments subtotal[(b)]	57	38	37	132	72	35	22	129
Total assets	239	38	37	314	155	35	22	212
Liabilities								
Deferred compensation obligation	—	(22)	—	(22)	—	(25)	—	(25)
Mark-to-market derivative liabilities[(c)]	—	—	—	—	(1)	—	—	(1)
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—
Total liabilities	—	(22)	—	(22)	—	(25)	—	(25)
Total net assets	$239	$ 16	$ 37	$292	$155	$ 10	$ 22	$187

	Pepco				DPL				ACE			
As of September 30, 2018	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	$102	$ —	$ —	$102	$26	$ —	$ —	$ 26
Rabbi trust investments												
Cash equivalents	41	—	—	41	—	—	—	—	—	—	—	—
Fixed income	—	6	—	6	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	36	58	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[(b)]	41	28	36	105	—	—	—	—	—	—	—	—
Total assets	76	28	36	140	102	—	—	102	26	—	—	26
Liabilities												
Deferred compensation obligation	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$76	$ 25	$ 36	$137	$102	$ (1)	$ —	$101	$26	$ —	$ —	$ 26

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Pepco				DPL				ACE			
As of December 31, 2017	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	$ —	$ —	$ —	$ —	$29	$ —	$ —	$ 29
Rabbi trust investments												
Cash equivalents	44	—	—	44	—	—	—	—	—	—	—	—
Fixed income	—	12	—	12	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	22	45	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[(b)]	44	35	22	101	—	—	—	—	—	—	—	—
Total assets	80	35	22	137	—	—	—	—	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Mark-to-market derivative liabilities[(c)]	—	—	—	—	(1)	—	—	(1)	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1	—	—	—	—
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$80	$ 31	$ 22	$133	$ —	$ (1)	$ —	$ (1)	$29	$ —	$ —	$ 29

(a) PHI excludes cash of $33 million and $12 million at September 30, 2018 and December 31, 2017, respectively, and includes long-term restricted cash of $19 million and $23 million at September 30, 2018 and December 31, 2017, respectively, which is reported in Other deferred debits on the Consolidated Balance Sheets. Pepco excludes cash of $12 million and $4 million at September 30, 2018 and December 31, 2017, respectively. DPL excludes cash of $8 million and $2 million at September 30, 2018 and December 31, 2017, respectively. ACE excludes cash of $11 million and $2 million at September 30, 2018 and December 31, 2017, respectively, and includes long-term restricted cash of $19 million and $23 million at September 30, 2018 and December 31, 2017, respectively, which is reported in Other deferred debits on the Consolidated Balance Sheets.

(b) The amount of unrealized gains/(losses) at PHI totaled less than $1 million for the three months ended September 30, 2018 and 2017, respectively. The amount of unrealized gains/(losses) at Pepco totaled $1 million and less than $1 million for the three months ended September 30, 2018 and 2017, respectively. The amount of unrealized gains/(losses) at PHI totaled $1 million and less than $1 million for the nine months ended September 30, 2018 and 2017, respectively. The amount of unrealized gains/(losses) at Pepco totaled less than $1 million for the nine months ended September 30, 2018 and 2017, respectively.

(c) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

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, 2018 and 2017:

	Generation					ComEd	PHI		Exelon
Three Months Ended September 30, 2018	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation	Total
Balance as of June 30, 2018	$585	$ 18	$ 737	$ 36	$ 1,376	$ (252)	$ 36	$ —	$1,160
Total realized / unrealized gains (losses)									
Included in net income	(1)	—	(259) [(a)]	13	(247)	—	1	—	(246)
Included in noncurrent payables to affiliates	(4)	—	—	—	(4)	—	—	4	—
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	—	2
Included in regulatory assets/liabilities	—	—	—	—	—	(7) [(b)]	—	(4)	(11)
Change in collateral	—	—	(44)	—	(44)	—	—	—	(44)
Purchases, sales, issuances and settlements									
Purchases	15	—	81	3	99	—	—	—	99
Sales	—	(20)	—	—	(20)	—	—	—	(20)
Settlements	(29)	—	—	—	(29)	—	—	—	(29)
Transfers into Level 3	—	—	3	—	3	—	—	—	3
Transfers out of Level 3	—	—	(6)	—	(6)	—	—	—	(6)
Balance at September 30, 2018	$566	$ —	$ 512	$ 52	$ 1,130	$ (259)	$ 37	$ —	$908
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2018	$(1)	$ —	$ (104)	$ 13	$ (92)	$ —	$ —	$ —	$(92)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					ComEd	PHI		Exelon
Nine Months Ended September 30, 2018	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts (c)	Eliminated in Consolidation	Total
Balance as of December 31, 2017	$648	$ 12	$ 552	$ 37	$ 1,249	$ (256)	$ 22	$ —	$1,015
Total realized / unrealized gains (losses)									
Included in net income	(1)	—	(188) (a)	14	(175)	—	3	—	(172)
Included in noncurrent payables to affiliates	—	—	—	—	—	—	—	—	—
Included in payable for Zion Station decommissioning	—	7	—	—	7	—	—	—	7
Included in regulatory assets	—	—	—	—	—	(3) (b)	—	—	(3)
Change in collateral	—	—	14	—	14	—	—	—	14
Purchases, sales, issuances and settlements									
Purchases	34	1	181	3	219	—	—	—	219
Sales	—	(20)	(3)	—	(23)	—	—	—	(23)
Settlements	(115)	—	—	—	(115)	—	12	—	(103)
Transfers into Level 3	—	—	(21)	—	(21)	—	—	—	(21)
Transfers out of Level 3	—	—	(23)	(2)	(25)	—	—	—	(25)
Balance as of September 30, 2018	$566	$ —	$ 512	$ 52	$ 1,130	$ (259)	$ 37	$ —	$908
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2018	$(5)	$ —	$ 159	$ 14	$ 168	$ —	$ —	$ —	$168

(a) Includes a reduction for the reclassification of $155 million and $347 million of realized losses due to the settlement of derivative contracts for the three and nine months ended September 30, 2018, respectively.
(b) Includes $4 million of increases in fair value and an increase for realized losses due to settlements of $3 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2018. Includes $9 million of decreases in fair value and an increase for realized losses due to settlements of $12 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the nine months ended September 30, 2018.
(c) The amounts represented are life insurance contracts at Pepco.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended September 30, 2017	Generation NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	ComEd Mark-to-Market Derivatives	PHI Life Insurance Contracts	Exelon Total[c]
Balance as of June 30, 2017	$683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$ 1,098
Total realized / unrealized gains (losses)								
Included in net income	—	—	(82) [a]	1	(81)	—	1	(80)
Included in noncurrent payables to affiliates	—	—	—	—	—	—	—	—
Included in payable for Zion Station decommissioning	—	(4)	—	—	(4)	—	—	(4)
Included in regulatory assets	—	—	—	—	—	(21) [b]	—	(21)
Change in collateral	—	—	11	—	11	—	—	11
Purchases, sales, issuances and settlements								
Purchases	19	—	57	1	77	—	—	77
Sales	—	—	—	—	—	—	—	—
Settlements	(31)	—	10	—	(21)	—	—	(21)
Transfers into Level 3	—	—	—	—	—	—	—	—
Transfers out of Level 3	—	—	10	—	10	—	—	10
Balance as of September 30, 2017	$671	$ 17	$ 595	$ 43	$ 1,326	$ (277)	$ 21	$ 1,070
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2017	$—	$ —	$ 24	$ 1	$ 25	$ —	$ 1	$ 26

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Generation					ComEd	PHI		Exelon
Nine Months Ended September 30, 2017	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts[c]	Eliminated in Consolidation	Total
Balance as of December 31, 2016	$677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$993
Total realized / unrealized gains (losses)									
Included in net income	4	—	(110) [a]	2	(104)	—	2	—	(102)
Included in noncurrent payables to affiliates	13	—	—	—	13	—	—	(13)	—
Included in payable for Zion Station decommissioning	—	(3)	—	—	(3)	—	—	—	(3)
Included in regulatory assets	—	—	—	—	—	(19) [b]	—	13	(6)
Change in collateral	—	—	81	—	81	—	—	—	81
Purchases, sales, issuances and settlements									
Purchases	54	1	146	4	205	—	—	—	205
Sales	—	—	(15)	—	(15)	—	—	—	(15)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(77)		(8)		(85)	—	—	—	(85)
Transfers into Level 3	—	—	(9)	—	(9)	—	—	—	(9)
Transfers out of Level 3	—	—	17	(5)	12	—	—	—	12
Balance as of September 30, 2017	$671	$ 17	$ 595	$ 43	$ 1,326	$ (277)	$ 21	$ —	$1,070
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2017	$2	$ —	$ 161	$ 2	$ 165	$ —	$ 2	$ —	$167

(a) Includes a reduction for the reclassification of $96 million and $279 million of realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2017, respectively.

(b) Includes $24 million of increases in fair value and an increase for realized losses due to settlements of $3 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2017. Includes $32 million of decreases in fair value and an increase for realized losses due to settlements of $13 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the nine months ended September 30, 2017.

(c) The amounts represented are life insurance contracts at Pepco.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

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, 2018 and 2017:

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net
Total gains (losses) included in net income for the three months ended September 30, 2018	$(176)	$ (83)	$ 12	$ 1	$(176)	$ (83)	$ 1	$ 12
Total gains (losses) included in net income for the nine months ended September 30, 2018	(32)	(156)	13	3	(32)	(156)	3	13
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2018	(64)	(40)	12	—	(64)	(40)	—	12
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2018	174	(15)	9	—	174	(15)	—	9

	Generation			PHI	Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net
Total gains (losses) included in net income for the three months ended September 30, 2017	$(3)	$ (69)	$ 1	$ 1	$(3)	$ (69)	$ 2
Total gains (losses) included in net income for the nine months ended September 30, 2017	34	(152)	6	2	34	(152)	8
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2017	47	(23)	1	1	47	(23)	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2017	222	(61)	4	2	222	(61)	6

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (All Registrants). The Registrants' cash equivalents include investments with original maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities and Fixed Income. Generation's and CENG's NDT fund investments policies outline investment guidelines for the trusts and limit the trust funds’ exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1 or Level 2.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds which are based on quoted prices in active markets are categorized in Level 1. Certain equity securities have been categorized as Level 2 because they are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third-party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity and fixed income commingled funds and mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives such as holding short-term fixed income securities or tracking the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For commingled funds and mutual funds, which are not publicly quoted, the funds are valued using NAV as a practical expedient for fair value, which is primarily derived from the quoted prices in active markets on the underlying securities, and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its

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equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending 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. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. 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.

As of September 30, 2018, Generation has outstanding commitments to invest in fixed income, middle market lending, private equity and real estate investments of approximately $135 million, $208 million, $349 million, and $227 million, respectively. These commitments will be funded by Generation’s existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of September 30, 2018. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of September 30, 2018, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 13 — Asset Retirement Obligations for additional information on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, and Pepco). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon’s executive management and directors. The Rabbi trusts assets are included in investments in the Registrants’ Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon’s overall investment strategy. Money market funds and mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The fair values of fixed income securities are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

Mark-to-Market Derivatives (Exelon, Generation, ComEd, PHI and DPL). Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives’ pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants’ derivatives are predominantly at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

Deferred Compensation Obligations (All Registrants). The Registrants’ deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants’ deferred compensation obligations is based on the market value of the participants’ notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

The value of certain employment agreement obligations (which are included with the Deferred Compensation Obligation in the tables above) are based on a known and certain stream of payments to be made over time and are categorized as Level 2 within the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd, PHI, Pepco, DPL and ACE)

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers’ inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations.

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Rabbi Trust Investments - Life insurance contracts (Exelon, PHI, and Pepco). For life insurance policies categorized as Level 3, the fair value is determined based on the cash surrender value of the policy, which contains unobservable inputs and assumptions. Because Exelon relies on its third-party insurance provider to develop the inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Exelon. Exelon gains an understanding of the types of inputs and assumptions used in preparing the valuations and performs procedures to assess the reasonableness of the valuations.

Mark-to-Market Derivatives (Exelon, Generation and ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. 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. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas and certain transmission congestion contracts. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.38 and $0.46 for power and natural gas, respectively. Many of the commodity derivatives are short-term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 10 —Derivative Financial Instruments for additional information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at September 30, 2018	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(b)]	$ 359	Discounted Cash Flow	Forward power price	$9	-$158
			Forward gas price	$1.10	-$12.57
		Option Model	Volatility percentage	8%	-211%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(b)]	$ 58	Discounted Cash Flow	Forward power price	$17	-$158
Mark-to-market derivatives (Exelon and ComEd)	$ (259)	Discounted Cash Flow	Forward heat rate[(c)]	10x	-11x
			Marketability reserve	4%	-8%
			Renewable factor	86%	-121%

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Type of trade	Fair Value at December 31, 2017	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[(a)(b)]	$ 445	Discounted Cash Flow	Forward power price	$3 - $124
			Forward gas price	$1.27 - $12.80
		Option Model	Volatility percentage	11% - 139%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[(a)(b)]	$ 26	Discounted Cash Flow	Forward power price	$14 - $94
Mark-to-market derivatives (Exelon and ComEd)	$ (256)	Discounted Cash Flow	Forward heat rate[(c)]	9x - 10x
			Marketability reserve	4% - 8%
			Renewable factor	88% - 120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $94 million and $81 million as of September 30, 2018 and December 31, 2017, 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 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.

10. 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.

Commodity Price Risk (All Registrants)

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. 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

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instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Derivative 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 normal purchase normal sale (NPNS), cash flow hedges and fair value hedges. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the consolidated company, referred to as economic hedges in the following tables. 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.

Fair value authoritative guidance and disclosures 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 Sheet. 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 referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation’s use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, 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 column. As of September 30, 2018, $23 million of cash collateral posted, and as of December 31, 2017, $4 million of cash collateral held, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or had no positions to offset as of the balance sheet date. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd’s use of cash collateral is generally unrestricted unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

Cash collateral held by PECO and BGE must be deposited in an unaffiliated major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

In the table below, DPL's economic hedges are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of September 30, 2018:

	Generation				ComEd	DPL			Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(e)]	Subtotal[(b)]	Economic Hedges[(c)]	Economic Hedges[(d)]	Collateral and Netting[(a)]	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 2,987	$ 113	$ (2,406)	$ 694	$ —	$ —	$ —	$ —	$ 694
Mark-to-market derivative assets (noncurrent assets)	1,383	61	(1,013)	431	—	—	—	—	431
Total mark-to-market derivative assets	4,370	174	(3,419)	1,125	—	—	—	—	1,125
Mark-to-market derivative liabilities (current liabilities)	(2,761)	(86)	2,543	(304)	(24)	—	—	—	(328)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,284)	(41)	1,088	(237)	(235)	—	—	—	(472)
Total mark-to-market derivative liabilities	(4,045)	(127)	3,631	(541)	(259)	—	—	—	(800)
Total mark-to-market derivative net assets (liabilities)	$ 325	$ 47	$ 212	$ 584	$ (259)	$ —	$ —	$ —	$ 325

(a) Exelon, Generation and DPL net all available amounts allowed under the derivative authoritative guidance on 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. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $71 million and $28 million, respectively, and current and noncurrent liabilities are shown net of collateral of $66 million and $47 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $212 million at September 30, 2018.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $(166) million represents variation margin on the exchanges.

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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2017:

	Generation				ComEd	DPL			Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(e)]	Subtotal[(b)]	Economic Hedges[(c)]	Economic Hedges[(d)]	Collateral and Netting[(a)]	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$3,061	$ 56	$ (2,144)	$ 973	$ —	$ —	$ —	$ —	$ 973
Mark-to-market derivative assets (noncurrent assets)	1,164	12	(845)	331	—	—	—	—	331
Total mark-to-market derivative assets	4,225	68	(2,989)	1,304	—	—	—	—	1,304
Mark-to-market derivative liabilities (current liabilities)	(2,646)	(43)	2,480	(209)	(21)	(1)	1	—	(230)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,137)	(10)	975	(172)	(235)	—	—	—	(407)
Total mark-to-market derivative liabilities	(3,783)	(53)	3,455	(381)	(256)	(1)	1	—	(637)
Total mark-to-market derivative net assets (liabilities)	$442	$ 15	$ 466	$ 923	$ (256)	$ (1)	$ 1	$ —	$ 667

(a) Exelon, Generation and DPL net all available amounts allowed under the derivative authoritative guidance on 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, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $169 million and $53 million, respectively, and current and noncurrent liabilities are shown net of collateral of $167 million and $77 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $466 million at December 31, 2017.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

(d) Represents natural gas futures purchased by DPL as part of a natural gas hedging program approved by the DPSC.

(e) Of the collateral posted/(received), $(117) million represents variation margin on the exchanges.

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Economic Hedges (Commodity Price Risk)
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. For the three and nine months ended September 30, 2018 and 2017, 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" on the Consolidated Statements of Cash Flows.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Income Statement Location	Gain (Loss)			
Operating revenues	$8	$ 55	$(99)	$(41)
Purchased power and fuel	66	21	(4)	(114)
Total Exelon and Generation	$74	$ 76	$(103)	$(155)

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, 2018, the percentage of expected generation hedged is 98%-101%, 82%-85% and 48%-51% for 2018, 2019 and 2020, respectively.
On December 17, 2010, ComEd executed several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.
PECO’s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches to achieve system supply reliability at the least cost. PECO’s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO’s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2018 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-

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term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2018 and previous PGC settlements, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 20% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's results of operations and financial position as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. BGE's commodity price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco's commodity price risk related to electric supply procurement is limited. Pepco locks in fixed prices for its SOS requirements through full requirements contracts. Certain of Pepco's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative costs. DPL locks in fixed prices for its SOS requirements through full requirements contracts. DPL's commodity price risk related to electric supply procurement is limited. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up against forecasts on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas

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commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to 50% of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The 50% hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its gas hedging program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the gas hedging program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's commodity price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. Certain of ACE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

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. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the 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 revenue from energy marketing activities. 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. For the three and nine months ended September 30, 2018 and 2017 Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also included in the "Net fair value changes related to derivatives" on the Consolidated Statements of Cash Flows. The Utility Registrants do not execute derivatives for proprietary trading purposes.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Income Statement Location	Gain (Loss)			
Operating revenues	$(3)	$ 5	$ 14	$ 4

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants also utilize interest rate swaps, which are treated as economic hedges, to manage their interest rate exposure. To manage foreign exchange rate exposure associated with

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international commodity purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are treated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of September 30, 2018:

	Generation			Exelon Corporate	Exelon
Description	Economic Hedges	Collateral and Netting(a)	Subtotal	Economic Hedges	Total
Mark-to-market derivative assets (current assets)	$3	$ (1)	$ 2	$ —	$ 2
Mark-to-market derivative assets (noncurrent assets)	18	—	18	—	18
Total mark-to-market derivative assets	21	(1)	20	—	20
Mark-to-market derivative liabilities (current liabilities)	(2)	1	(1)	—	(1)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	—	—	(10)	(10)
Total mark-to-market derivative liabilities	(2)	1	(1)	(10)	(11)
Total mark-to-market derivative net assets (liabilities)	$19	$ —	$ 19	$ (10)	$ 9

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on 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 counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2017:

	Generation				Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting(a)	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$—	$ 10	$ (7)	$ 3	$ —	$ 3
Mark-to-market derivative assets (noncurrent assets)	3	—	—	3	3	6
Total mark-to-market derivative assets	3	10	(7)	6	3	9
Mark-to-market derivative liabilities (current liabilities)	(2)	(7)	7	(2)	—	(2)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(2)	—	(2)	—	(2)
Total mark-to-market derivative liabilities	(2)	(9)	7	(4)	—	(4)
Total mark-to-market derivative net assets	$1	$ 1	$ —	$ 2	$ 3	$ 5

(a) Exelon and Generation net all available amounts allowed under the derivative authoritative guidance on 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 counterparty exposures subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral, which are not reflected in the table above.

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Economic Hedges (Interest Rate and Foreign Exchange Risk)
Exelon and Generation execute these instruments to mitigate exposure to fluctuations in interest rates or foreign exchange but for which the fair value or cash flow hedge elections were not made. On July 1, 2018, Exelon de-designated its fair value hedges related to interest rate risk and Generation de-designated its cash flow hedges related to interest rate risk. The amount deferred in AOCI associated with the previously designated cash flow hedges will be reclassified into earnings as the underlying forecasted transaction occurs. The result of this de-designation is that all economic hedges for interest rate swaps will be recorded at fair value through earnings going forward, referred to as economic hedges in the following tables.
The following table provides notional amounts outstanding held by Exelon and Generation at September 30, 2018 related to interest rate swaps and foreign currency exchange rate swaps.

	Generation	Exelon Corporate	Exelon
Foreign currency exchange rate swaps	$ 88	$ —	$88
Interest rate swaps	625	800	1,425
Total	$ 713	$ 800	$1,513

The following table provides notional amounts outstanding held by Exelon and Generation at December 31, 2017 related to interest rate swaps and foreign currency exchange rate swaps.

	Generation	Exelon Corporate	Exelon
Foreign currency exchange rate swaps	$ 94	$ —	$ 94
Interest rate swaps[(a)]	1	—	1
Total	$ 95	$ —	$ 95

(a) On July 1, 2018, Exelon and Generation de-designated its fair value and cash flow hedges. The table excludes amounts of $800 million of fixed-to-floating hedges that were previously designated as fair value hedges by Exelon and $636 million of floating-to-fixed hedges that were previously designated as cash flow hedges by Exelon and Generation as of December 31, 2017.

For the three and nine months ended September 30, 2018 and 2017, Exelon and Generation recognized the following net pre-tax mark-to-market gains (losses) in the Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s and Generation’s Consolidated Statements of Cash Flows.

		Three Months Ended September 30,		Nine Months Ended September 30,	
		2018	2017	2018	2017
	Income Statement Location	Gain (Loss)			
Generation	Operating Revenues	$(2)	$(3)	$3	$(6)
Generation	Purchased Power and Fuel	(1)	—	(4)	—
Generation	Interest Expense	4	—	4	—
Total Generation		$1	$(3)	$3	$(6)

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		Three Months Ended September 30,		Nine Months Ended September 30,	
		2018	2017	2018	2017
	Income Statement Location	Gain (Loss)			
Exelon	Operating Revenues	$(2)	$(3)	$3	$(6)
Exelon	Purchased Power and Fuel	(1)	—	(4)	—
Exelon	Interest Expense	2	—	2	—
Total Exelon		$(1)	$(3)	$1	$(6)

Fair Value Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in earnings immediately. Exelon had no fixed-to-floating swaps designated as fair value hedges as of September 30, 2018 and had $800 million notional amounts designated as fair value hedges as of December 31, 2017. Exelon and Generation include the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps as follows:

		Three Months Ended September 30,			
	Income Statement Location	2018	2017	2018	2017
		Loss on Swaps		Gain on Borrowings	
Exelon	Interest expense	$—	$(2)	$ —	$ 6

		Nine Months Ended September 30,			
	Income Statement Location	2018	2017	2018	2017
		Loss on Swaps		Gain on Borrowings	
Exelon	Interest expense	$(11)	$(6)	$ 20	$ 17

During the three months ended September 30, 2018, due to the de-designation of fair value hedges, there was no impact on the results of operations as a result of ineffectiveness from fair value hedges. During the three months ended September 30, 2017, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $4 million gain. During the nine months ended September 30, 2018 and 2017, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $9 million gain and a $11 million gain, respectively.

Cash Flow Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as cash flow hedges, the gain or loss on the effective portion of the derivative will be deferred in AOCI and reclassified into earnings when the underlying transaction occurs. Exelon and Generation have no floating-to-fixed swaps designated as cash flow hedges as of September 30, 2018, and had $636 million notional amounts designated as cash flow hedges as of December 31, 2017.

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The tables below provide the activity of OCI related to cash flow hedges for the three and nine months ended September 30, 2018 and 2017, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from OCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended September 30, 2018	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at June 30, 2018		$ (4)	$ (2)
Reclassifications from AOCI to net income	Interest Expense	—	—
AOCI derivative loss at September 30, 2018		$ (4)	$ (2)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Nine Months Ended September 30, 2018	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at December 31, 2017		$ (16)	$ (14)
Effective portion of changes in fair value		11	11
Reclassifications from AOCI to net income	Interest Expense	1	1
AOCI derivative loss at September 30, 2018		$ (4)	$ (2)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended September 30, 2017	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at June 30, 2017		$ (14)	$ (12)
Effective portion of changes in fair value		1	1
Reclassifications from AOCI to net income	Interest Expense	(1) [(a)]	(1) [(a)]
AOCI derivative loss at September 30, 2017		$ (14)	$ (12)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Nine Months Ended September 30, 2017	Income Statement Location	Generation Total Cash Flow	Exelon Total Cash

		Hedges	Flow Hedges
AOCI derivative loss at December 31, 2016		$ (19)	$ (17)
Effective portion of changes in fair value		2	2
Reclassifications from AOCI to net income	Interest Expense	3 (b)	3 (b)
AOCI derivative loss at September 30, 2017		$ (14)	$ (12)

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(a) Amount is net of related income tax benefit of $1 million for the three months ended September 30, 2017.
(b) Amount is net of related income tax expense of $2 million for the nine months ended September 30, 2017.

During the three months ended September 30, 2018, due to the de-designation of cash flow hedges, there was no impact on the results of operations as a result of ineffectiveness. During the nine months ended September 30, 2018 and the three and nine months ended September 30, 2017, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial. The estimated amount of existing gains and losses that are reported in AOCI at the reporting date that are expected to be reclassified into earnings within the next twelve months is immaterial.

Proprietary Trading (Interest Rate and Foreign Exchange Risk)

Generation also executes derivative contracts for proprietary trading purposes to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. 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 "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. For the three and nine months ended September 30, 2018 and for the three months ended September 30, 2017, Exelon and Generation recognized no net pre-tax commodity mark-to-market gains or losses. For the nine months ended September 30, 2017, Exelon and Generation recognized a $1 million net pre-tax commodity mark-to-market loss.

Credit Risk, Collateral and Contingent-Related Features (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. 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.

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The following tables provide information on Generation’s credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2018. 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 figures 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. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $47 million, $26 million, $23 million, $39 million, $8 million, and $6 million as of September 30, 2018, respectively.

Rating as of September 30, 2018	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	$ 647	$ —	$ 647	1	$ 176
Non-investment grade	101	20	81		
No external ratings					
Internally rated — investment grade	179	1	178		
Internally rated — non-investment grade	139	17	122		
Total	$ 1,066	$ 38	$ 1,028	1	$ 176

Net Credit Exposure by Type of Counterparty	As of September 30, 2018
Financial institutions	$ 19
Investor-owned utilities, marketers, power producers	572
Energy cooperatives and municipalities	357
Other	80
Total	$ 1,028

(a) As of September 30, 2018, credit collateral held from counterparties where Generation had credit exposure included $4 million of cash and $34 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd’s power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on daily, updated forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price on a given day, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd’s net credit exposure. As of September 30, 2018, ComEd’s net credit exposure to suppliers was less than $2 million.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd’s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

PECO’s unsecured credit used by the suppliers represents PECO’s net credit exposure. As of September 30, 2018, PECO had no material net credit exposure to suppliers.

PECO’s natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO’s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. As of September 30, 2018, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE’s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

BGE’s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier’s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. As of September 30, 2018, BGE's net credit exposure to suppliers was immaterial.

BGE’s regulated gas business is exposed to market-price risk. At September 30, 2018, BGE's credit exposure related to off-system sales, which is mitigated by parental guarantees, letters of credit or right to offset clauses within other contracts with those third-party suppliers, was immaterial.

Pepco’s, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier’s lowest credit rating from the major credit rating agencies and the supplier’s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier’s unsecured credit limit. The unsecured credit used by the suppliers represents Pepco’s, DPL's and ACE's net credit exposure. As of September 30, 2018, Pepco’s, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco’s, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

DPL’s natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL’s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of September 30, 2018, DPL's credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

Collateral (All Registrants)

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

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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, 2018	December 31, 2017
Gross fair value of derivative contracts containing this feature[(a)]	$ (1,704)	$ (926)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	1,249	577
Net fair value of derivative contracts containing this feature[(c)]	$ (455)	$ (349)

(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 a Registrant 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.

Generation had cash collateral posted of $255 million and letters of credit posted of $283 million and cash collateral held of $20 million and letters of credit held of $48 million as of September 30, 2018 for external counterparties with derivative positions. Generation had cash collateral posted of $497 million and letters of credit posted of $293 million and cash collateral held of $35 million and letters of credit held of $33 million at December 31, 2017 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody’s), Generation would have been required to post additional collateral of $1.8 billion as of September 30, 2018 and December 31, 2017. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.
Generation’s and Exelon’s interest rate swaps contain provisions that, in the event of a merger, if Generation’s debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of September 30, 2018, Generation's and Exelon's swaps were in an asset position of $19 million and $9 million, respectively.

See Note 25 — Segment Information of the Exelon 2017 Form 10-K for additional information regarding the letters of credit supporting the cash collateral.

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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. Under the terms of ComEd’s standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of September 30, 2018, ComEd held $6 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's REC and ZEC contracts, collateral postings are required to cover a percentage of the REC and ZEC contract value. As of September 30, 2018, ComEd held $20 million in collateral from suppliers for REC and ZEC contract obligations. Under the terms of ComEd’s long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of September 30, 2018, ComEd held $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of September 30, 2018, it would have been required to post approximately $8 million of collateral to its counterparties. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information.

PECO’s natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO’s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of September 30, 2018, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2018, PECO could have been required to post $22 million of collateral to its counterparties.

PECO’s supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE’s natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE’s credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of September 30, 2018, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2018, BGE could have been required to post $31 million of collateral to its counterparties.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of September 30, 2018, DPL could have been required to post an additional amount of $10 million of collateral to its counterparties.

BGE's, Pepco's, DPL's and ACE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE, Pepco, DPL or ACE to post collateral.

11. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon Corporate, ComEd, BGE, Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity

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requirements primarily through the issuance of commercial paper and borrowings from the Exelon 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 Registrants had the following amounts of commercial paper borrowings outstanding as of September 30, 2018 and December 31, 2017:

Commercial Paper Borrowings	September 30, 2018	December 31, 2017
Exelon	$ 209	$ 427
BGE	—	77
PHI[(a)]	209	350
Pepco	64	26
DPL	—	216
ACE	145	108

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(a) PHI reflects the commercial paper borrowings outstanding of Pepco, DPL and ACE.

Short-Term Loan Agreements

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured. On March 23, 2017, the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement was fully repaid and the loan terminated. On March 23, 2017, Exelon Corporate entered into a similar type term loan for $500 million which expired March 22, 2018. The loan agreement was renewed on March 22, 2018 and will expire on March 21, 2019. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% and all indebtedness thereunder is unsecured.

On May 23, 2018, ACE entered into two term loan agreements in the aggregate amount of $125 million, which expire on May 22, 2019. Pursuant to the term loan agreements, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.55% and all indebtedness thereunder is unsecured.

Credit Agreements

As of March 15, 2018, the credit agreement for a Generation bilateral credit facility of $30 million was amended to increase the overall facility size to $95 million. This facility will solely be used by Generation to issue letters of credit.

On May 26, 2018, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2023.

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Long-Term Debt
Issuance of Long-Term Debt
During the nine months ended September 30, 2018, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.72 %	November 30, 2018	$ 4	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Energy Efficiency Project Financing	3.17 %	October 31, 2018	$ 1	Funding to install energy conservation measures in Brooklyn, NY.
Generation	Energy Efficiency Project Financing	2.61 %	September 30, 2018	$ 5	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing	4.17 %	January 1, 2019	$ 1	Funding to install energy conservation measures for the General Services Administration Philadelphia project.
Generation	Energy Efficiency Project Financing	4.26 %	May 1, 2019	$ 3	Funding to install energy conservation measures for the National Institutes of Health Multi-Buildings Phase II project.
ComEd	First Mortgage Bonds, Series 124	4.00 %	March 1, 2048	$ 800	Refinance one series of maturing first mortgage bonds, to repay a portion of ComEd's outstanding commercial paper obligations and to fund general corporate purposes.
ComEd	First Mortgage Bonds, Series 125	3.70 %	August 15, 2028	$ 550	Repay a portion of ComEd's outstanding commercial paper obligations and to fund general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.90 %	March 1, 2048	$ 325	Refinance a portion of maturing mortgage bonds.
PECO	Loan Agreement	2.00 %	June 20, 2023	$ 50	Funding to implement Electric Long-term Infrastructure Improvement Plan.
PECO	First and Refunding Mortgage Bonds	3.90 %	March 1, 2048	$ 325	Satisfy short-term borrowings from the Exelon intercompany money pool and for general corporate purposes.
BGE	Senior Notes	4.25 %	September 15, 2048	$ 300	Repay commercial paper obligations and for general corporate purposes.
Pepco	First Mortgage Bonds	4.27 %	June 15, 2048	$ 100	Repay existing indebtedness and for general corporate purposes.
DPL	First Mortgage Bonds	4.27 %	June 15, 2048	$ 200	Repay existing indebtedness and for general corporate purposes.

On October 16, 2018, ACE issued $350 million of 4.00% First Mortgage Bonds due October 15, 2028. The proceeds will be used to refinance ACE's 7.75% First Mortgage Bonds due November 15, 2018, reduce short-term borrowings and for general corporate purposes.
On November 1, 2018, Pepco issued $100 million of 4.31% First Mortgage Bonds due November 1, 2048. The proceeds will be used to repay existing indebtedness and for general corporate purposes.
12. Income Taxes (All Registrants)
Corporate Tax Reform (All Registrants)
On December 22, 2017, President Trump signed the TCJA into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to

21%; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5)

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eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017. The most significant change that impacts the Registrants is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018.

Pursuant to the enactment of the TCJA, the Registrants remeasured their existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to their net deferred income tax liability balances as shown in the table below. Generation recorded a corresponding net decrease to income tax expense, while the Utility Registrants recorded corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. The amount and timing of potential settlements of the established net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. See Note 6 — Regulatory Matters for additional information.

The Registrants assessed the majority of the applicable provisions in the TCJA and have recorded the associated impacts as of December 31, 2017. As discussed further below, under SAB 118 issued by the SEC in December 2017, the Registrants have recorded provisional income tax amounts as of December 31, 2017 for changes pursuant to the TCJA related to depreciation for which the impacts could not be finalized upon issuance of the Registrants' financial statements, but for which reasonable estimates could be determined.

On August 3, 2018, the U.S. Department of Treasury in conjunction with the IRS released proposed regulations clarifying the immediate expensing depreciation provisions enacted by the TCJA, specifically that regulated utility property acquired after September 27, 2017 and placed in service by December 31, 2017 qualifies for 100% expensing. Until the proposed regulations are finalized, taxpayers may rely on the proposed regulations for tax years ending after September 28, 2017.

While the Registrants have recorded the impacts of the TCJA based on their interpretation of the provisions as enacted, it is expected that Treasury and the IRS will issue additional interpretative guidance in the future which could result in changes to previously finalized provisions. At this time, many of the states in which Exelon does business have issued guidance regarding TCJA and the impact is not material.

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The one-time impacts recorded by the Registrants to remeasure their deferred income tax balances at the 21% corporate federal income tax rate as of December 31, 2017 are presented below. The impact of the August 3, 2018 proposed regulations to these balances is not material.

	Exelon[b]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Decrease to Deferred Income Tax Liability Balances	$ 8,624	$ 1,895	$2,819	$1,407	$1,120	$1,944	$968	$540	$456

	Exelon	Generation	ComEd	PECO[c]	BGE	PHI	Pepco	DPL	ACE
Net Regulatory Liability Recorded[a]	$7,315	N/A	$2,818	$ 1,394	$1,124	$1,979	$976	$545	$458

	Exelon[b]	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Net Deferred Income Tax Benefit/(Expense) Recorded	$ 1,309	$ 1,895	$ 1	$ 13	$(4)	$(35)	$(8)	$(5)	$(2)

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(a) Reflects the net regulatory liabilities recorded on a pre-tax basis before taking into consideration the income tax benefits associated with the ultimate settlement with customers.

(b) Amounts do not sum across due to deferred tax adjustments recorded at the Exelon Corporation parent company, primarily related to certain employee compensation plans.

(c) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO was in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. See Note 6 - Regulatory Matters for additional information.

The net regulatory liabilities above include (1) amounts subject to IRS “normalization” rules that are required to be passed back to customers generally over the remaining useful life of the underlying assets giving rise to the associated deferred income taxes, and (2) amounts for which the timing of settlement with customers is subject to determinations by the rate regulators. The table below sets forth the Registrants’ estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

	Exelon	ComEd	PECO[a]	BGE	PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$3,040	$1,400	$ 533	$459	$648	$ 299	$195	$153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$4,734	$1,973	$ 576	$783	$1,402	$ 690	$389	$323

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(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. See Note 6 - Regulatory Matters for additional information.

The net regulatory liability amounts subject to the IRS normalization rules generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the other amounts, the pass back period is subject to determinations by the rate regulators. See Note 6 - Regulatory Matters for the status of and information regarding the Registrants' TCJA-related regulatory filings.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	(1.2)	(9.0)	8.3	(3.6)	7.3	0.2	1.0	6.6	7.3
Qualified nuclear decommissioning trust fund income	2.4	5.8	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.6)	(1.1)	(0.2)	(0.1)	—	(0.2)	(0.1)	(0.3)	(0.3)
Plant basis differences	(2.5)	—	(0.3)	(15.2)	(0.8)	(2.0)	(3.4)	(0.7)	(1.3)
Production tax credits and other credits	(1.2)	(2.9)	(0.1)	—	—	—	—	—	—
Noncontrolling interests	(1.1)	(2.8)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.8)	—	(7.8)	(4.6)	(7.9)	(17.7)	(21.2)	(14.0)	(15.4)
Tax Cuts and Jobs Act of 2017	1.3	3.5	—	—	—	0.2	0.1	—	—
Other	3.2	5.6	0.3	0.9	2.6	0.6	0.3	0.6	0.3
Effective income tax rate	14.5%	20.1%	21.2%	(1.6)%	22.2%	2.1%	(2.3)%	13.2%	11.6%

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Three Months Ended September 30, 2017[(a)]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	2.2	5.6	6.6	(0.1)	5.3	5.1	2.2	5.3	5.6
Qualified nuclear decommissioning trust fund income	2.6	5.8	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.1)	(2.2)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.4)
Plant basis differences	(2.6)	—	(0.3)	(14.6)	(0.8)	(4.9)	(6.7)	(1.9)	(3.4)
Production tax credits and other credits	(2.2)	(4.9)	—	—	—	—	—	—	—
Noncontrolling interests	0.5	1.1	—	—	—	—	—	—	—
Fitzpatrick bargain purchase gain	(0.2)	(0.4)	—	—	—	—	—	—	—
Other	(0.1)	0.3	(0.2)	(0.2)	(0.2)	0.2	—	(0.2)	0.1
Effective income tax rate	34.1%	40.3%	40.9%	20.0%	39.2%	35.2%	30.4%	38.0%	36.9%

	Nine Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	1.7	(2.6)	8.2	(3.6)	6.6	2.7	2.4	6.5	7.3
Qualified nuclear decommissioning trust fund income	0.9	2.6	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(2.2)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.3)	(0.3)
Plant basis differences	(2.7)	—	(0.1)	(15.4)	(0.7)	(1.9)	(2.9)	(0.7)	(1.3)
Production tax credits and other credits	(1.8)	(5.1)	(0.1)	—	—	—	—	—	—
Noncontrolling interests	(1.1)	(3.2)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.1)	—	(7.6)	(3.4)	(8.1)	(14.5)	(16.5)	(11.0)	(14.0)
Tax Cuts and Jobs Act of 2017	0.2	1.3	(0.2)	—	—	0.3	—	—	—
Other	0.4	2.0	0.1	—	0.9	0.3	—	0.4	0.9
Effective income tax rate	11.6%	13.8%	21.1%	(1.5)%	19.6%	7.7%	3.9%	15.9%	13.6%

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Nine Months Ended September 30, 2017[a]								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	0.7	2.2	5.9	(0.1)	5.2	4.9	3.0	5.1	5.6
Qualified nuclear decommissioning trust fund income	4.0	13.6	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(2.7)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.4)
Plant basis differences	(3.4)	—	(0.3)	(14.4)	(0.8)	(4.6)	(6.3)	(1.8)	(3.4)
Production tax credits and other credits	(1.8)	(6.0)	—	—	—	—	—	—	—
Noncontrolling interests	0.1	0.3	—	—	—	—	—	—	—
Merger expenses[c]	(5.4)	(2.4)	—	—	—	(11.8)	(8.0)	(10.0)	(23.0)
FitzPatrick bargain purchase gain	(3.2)	(10.9)	—	—	—	—	—	—	—
Like-Kind Exchange[b]	(1.7)	—	1.7	—	—	—	—	—	—
Other	0.1	(0.4)	0.2	—	0.2	—	(0.3)	0.6	(0.3)
Effective income tax rate	23.5%	28.7%	42.3%	20.4%	39.5%	23.3%	23.3%	28.7%	13.5%

(a) Exelon retrospectively adopted the new standard Revenue from Contracts with Customers. The standard was adopted as of January 1, 2018. The effective income tax rates are recast to reflect the impact of the new standard.
(b) Exelon and ComEd recorded the impact of the IRS's finalization of the LKE computation in the second quarter of 2017.
(c) Includes a remeasurement of uncertain federal and state income tax positions.

Accounting for Uncertainty in Income Taxes

The Registrants have the following unrecognized tax benefits as of September 30, 2018 and December 31, 2017:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
September 30, 2018	$ 804	$ 527	$ 2	$ —	$ 120	$ 134	$ 67	$ 21	$ 14

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2017	$ 743	$ 468	$ 2	$ —	$ 120	$ 125	$ 59	$ 21	$ 14

As a result of a court decision issued in July 2018 to an unrelated taxpayer, Exelon's and Generation’s unrecognized federal and state tax benefits increased in the third quarter of 2018 by approximately $71 million. Approximately $20 million of this increase impacted Exelon's and Generation’s effective tax rate and resulted in a charge to earnings in the third quarter of 2018.

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

Like-Kind Exchange

As of September 30, 2018, Exelon and ComEd have approximately $33 million and $2 million, respectively, of unrecognized federal and state tax benefits related to the like-kind exchange litigation described further below. If Exelon decides not to appeal the October 2018 U.S. Court of Appeals for the Seventh Circuit's decision, Exelon's and ComEd's unrecognized tax benefits will decrease in the fourth quarter. See below for further details.

Settlement of Income Tax Audits, Refund Claims, and Litigation

As of September 30, 2018, Exelon, Generation, PHI and ACE have approximately $515 million, $501 million, $14 million and $14 million of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, and the outcomes of pending court cases. Of the above unrecognized tax benefits, Exelon and Generation have $473 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to PHI and ACE, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

As of September 30, 2018, Exelon, Generation, BGE, PHI, Pepco and DPL have approximately $241 million, $33 million, $120 million, $88 million, $67 million, and $21 million, respectively, of unrecognized state tax benefits that will decrease in the fourth quarter of 2018 due to the receipt of favorable guidance with respect to the deductibility of certain depreciable fixed assets. The recognition of these tax benefits will decrease the effective tax rate at Exelon and Generation in the fourth quarter of 2018, which will result in an income tax benefit of approximately $26 million. The recognition of the tax benefits related to BGE, PHI, Pepco and DPL will be offset by corresponding regulatory liabilities and that portion will have no immediate impact to their effective tax rate.

Other Income Tax Matters

Like-Kind Exchange (Exelon and ComEd)

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd’s fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. As previously disclosed, Exelon terminated its investment in one of the leases in 2014 and the remaining two leases were terminated in 2016.

The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which is a listed transaction that the IRS has identified as a potentially abusive tax shelter. Thus, they disagreed with Exelon's position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. In 2013, the IRS issued a notice of deficiency to Exelon and Exelon filed a petition to initiate litigation in the United States Tax Court. In 2016, the Tax Court held that Exelon was not entitled to defer gain on the transaction. In addition to the tax and interest related to the gain deferral, the Tax Court also ruled that Exelon was liable for $90 million in penalties and interest on the penalties. Exelon has fully paid the amounts assessed resulting from the Tax Court decision.

In September 2017, Exelon appealed the Tax Court decision to the U.S. Court of Appeals for the Seventh Circuit. In October 2018, the U.S. Court of Appeals for the Seventh Circuit affirmed the Tax Court’s decision. Exelon is evaluating whether to pursue any further appeals of the decision.

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State Income Tax Law Changes

On April 24, 2018, Maryland enacted companion bills, House Bill 1794 and Senate Bill 1090, providing for a phase in of a single sales factor apportionment formula from the current three factor formula for determining an entity's Maryland state income taxes. The single sales factor will be fully phased in by 2022.

In the second quarter of 2018, Exelon, Generation, PHI, Pepco and DPL recorded a one-time increase to deferred income taxes of approximately $16 million, $5 million, $17 million, $16 million and $1 million, respectively. At PHI, Pepco and DPL, the increase to the Maryland deferred income tax liability was offset by regulatory assets. Further, the change in tax law is not expected to have a material ongoing impact to Exelon's, Generation's, PHI's, Pepco's or DPL's future results of operations.

Long-Term Marginal State Income Tax Rate (Exelon, Generation, PHI and Pepco)

In the third quarter of 2018, Exelon reviewed and updated its marginal state income tax rates based on 2017 state apportionment rates. As a result of the rate changes, in the third quarter of 2018, Exelon, Generation, PHI and DPL recorded a one-time decrease to deferred income taxes of approximately $50 million, $53 million, $4 million and $2 million, respectively. Pepco recorded a one-time increase to deferred incomes taxes of approximately $1 million. Exelon, PHI and DPL recorded a corresponding regulatory liability of approximately $1 million, $1 million and $2 million, respectively. Pepco recorded a corresponding regulatory asset of approximately $1 million. In the third quarter of 2018, Exelon, Generation and PHI recorded a decrease to income tax expense (net of federal taxes) of approximately $50 million, $53 million and $3 million, respectively.

13. Asset Retirement Obligations (Exelon, Generation and Pepco)

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

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 following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon’s and Generation’s Consolidated Balance Sheets from December 31, 2017 to September 30, 2018:

Nuclear decommissioning ARO at December 31, 2017 [a]	$9,662
Oyster Creek transferred to Liabilities held for sale	(783)
Accretion expense	357
Net increase due to changes in, and timing of, estimated future cash flows	116
Costs incurred related to decommissioning plants	(35)
Nuclear decommissioning ARO at September 30, 2018 [a]	$9,317

(a) Includes $12 million and $13 million for the current portion of the ARO at September 30, 2018 and December 31, 2017, respectively, which is included in Other current liabilities on Exelon’s and Generation’s Consolidated Balance Sheets.

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During the nine months ended September 30, 2018, Generation's total nuclear ARO decreased by approximately $345 million, primarily reflecting the reclassification of Oyster Creek ARO as Liabilities held for sale on Exelon's and Generation's Consolidated Balance Sheets following the announced agreement to sell Oyster Creek, offset by the accretion of the ARO liability due to the passage of time, and the impacts of ARO updates completed during 2018. The $116 million increase in the ARO during 2018 due to changes in the amounts and timing of estimated decommissioning cash flows includes a $32 million increase in the first quarter for the impact of the early retirement of Oyster Creek and a $84 million increase in the third quarter for the remeasurement of the ARO to reflect the announced pending sale of Oyster Creek. See Note 4 — Mergers, Acquisitions and Dispositions and Note 8 - Early Plant Retirements for additional information.

Nuclear Decommissioning Trust Fund Investments (Exelon and Generation)

NDT funds have been established for each generation station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2018, and the effective rates currently yield annual collections of approximately $4 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2023. See Note 15 — Asset Retirement Obligations of Exelon's 2017 Form 10-K, for information regarding the amount collected from PECO ratepayers for decommissioning costs.

Exelon and Generation had NDT fund investments totaling $12,584 million and $13,349 million at September 30, 2018 and December 31, 2017, respectively. The decrease is primarily driven by the reclassification of $903 million of Oyster Creek NDT as Assets held for sale on Exelon's and Generation's Consolidated Balance Sheets, partially offset by improved market performance. See Note 4 - Mergers, Acquisitions and Dispositions for additional information regarding the announced pending sale of Oyster Creek. The NDT fund investments include $120 million and $77 million for the current portion of the NDT at September 30, 2018 and December 31, 2017, respectively, which are included in Other current assets on Exelon's and Generation's Consolidated Balance Sheets.

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The following table provides net unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2018 and 2017:

	Exelon and Generation Three Months Ended September 30,		Exelon and Generation Nine Months Ended September 30,	
	2018	2017	2018	2017
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units[(a)]	$(66)	$ 44	$(335)	$253
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units[(b)(c)]	72	111	(143)	347

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.

(b) Excludes $9 million and $4 million of net unrealized losses related to the Zion Station pledged assets for the three months ended September 30, 2018 and 2017, respectively. Excludes $7 million and $5 million of net unrealized losses related to the Zion Station pledged assets for the nine months ended September 30, 2018 and 2017, respectively. Net unrealized losses related to Zion Station pledged assets are included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

(c) Net unrealized gains (losses) related to Generation's NDT funds with Non-Regulatory Agreement Units are included in Other, net on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units are eliminated in Other, net on Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

See Note 3 — Regulatory Matters and Note 26 — Related Party Transactions of the Exelon 2017 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning (Exelon and Generation)

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 15 — Asset Retirement Obligations of the Exelon 2017 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction. ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, are recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal and will complete all remaining decommissioning activities associated with the SNF dry storage facility.

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Generation has a liability of approximately $118 million which is included within the nuclear decommissioning ARO at September 30, 2018. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at September 30, 2018 and December 31, 2017:

	Exelon and Generation	
	September 30, 2018	December 31, 2017
Carrying value of Zion Station pledged assets[(a)]	$ 9	$ 39
Payable to Zion Solutions[(b)(c)]	9	37
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(d)]	965	942

(a) Included in Other current assets within Exelon's and Generation's Consolidated Balance sheets.
(b) Excludes a liability recorded within Exelon’s and Generation’s Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT funds. The NDT funds will be utilized to satisfy the tax obligations as gains and losses are realized.
(c) Included in Other current liabilities within Exelon’s and Generation’s Consolidated Balance Sheets.
(d) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

NRC Minimum Funding Requirements (Exelon and Generation)

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 March 30, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions (see Zion Station Decommissioning above). The status report demonstrated adequate decommissioning funding assurance for all units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed under Nuclear Decommissioning Trust Fund Investments above, the amount collected from PECO ratepayers has been adjusted effective January 1, 2018.

On March 28, 2018, Generation submitted its annual decommissioning funding status report with the NRC for shutdown reactors, reactors within five years of shut down except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above), and reactor involved in an acquisition. This report reflected the status of decommissioning funding assurance as of December 31, 2017 and included an update for the acquisition of FitzPatrick on March 31, 2017, the early retirement of TMI announced on May 30, 2017, an adjustment for the February 2, 2018 announced retirement date of Oyster Creek, and the updated status of Peach Bottom Unit 1 based on the new collections rate described above. As of December 31, 2017, Generation provided adequate decommissioning funding assurance for all of its shutdown reactors, reactors within five years of shutdown, and reactor involved in an acquisition.

Generation will file its next decommissioning funding status report for all units with the NRC by March 31, 2019. This report will reflect the status of decommissioning funding assurance as of December 31, 2018. A shortfall at any unit could necessitate that Generation address the shortfall by, among other

things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantee or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the decommissioning trust fund investment performance going forward.

Non-Nuclear Asset Retirement Obligations (Pepco)

Pepco has AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. In the third quarter of 2018, Pepco recorded an increase of $22 million in Operating and maintenance expense primarily related to asbestos identified at its Buzzard Point property as part of an annual ARO study. Buzzard Point is a waterfront property in the District of Columbia occupied by an active substation and former Pepco operated steam plant building, which Pepco retired and closed in 1981. Pepco’s AROs were $38 million and $3 million at September 30, 2018 and December 31, 2017, respectively.

14. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired Generation and BSC non-represented employees are not eligible for pension benefits and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits.

During the first quarter of 2017, in connection with the acquisition of FitzPatrick, Exelon established a new qualified pension plan and a new OPEB plan and recorded a provisional obligation for Fitzpatrick employees based on information available at the merger date of $38 million and $11 million, respectively. As permitted by business combinations authoritative guidance, during the third quarter of 2017, Exelon updated those obligations based on a final valuation for FitzPatrick employees as of the merger date of March 31, 2017. The updated obligations for pension and OPEB were $16 million and $17 million, respectively. See Note 4 — Mergers, Acquisitions and Dispositions for additional information of the acquisition of FitzPatrick.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2018, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2018. This valuation resulted in an increase to the pension and OPEB obligations of $23 million and $14 million, respectively. Additionally, accumulated other comprehensive loss decreased by $18 million (after-tax) and regulatory assets and liabilities increased by $61 million and $1 million, respectively.

The majority of the 2018 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.62%. The majority of the 2018 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.60% for funded plans and a discount rate of 3.61%.

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A portion of the net periodic benefit cost for all plans is capitalized within 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, 2018 and 2017.

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2018	2017[(a)]	2018	2017[(a)]
Components of net periodic benefit cost:				
Service cost	$100	$98	$28	$26
Interest cost	201	211	43	45
Expected return on assets	(312)	(300)	(43)	(39)
Amortization of:				
Prior service cost (benefit)	—	(1)	(47)	(47)
Actuarial loss	158	152	18	15
Settlement charges	—	1	—	—
Net periodic benefit cost	$147	$161	$(1)	$—

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2018	2017[(a)]	2018	2017[(a)]
Components of net periodic benefit cost:				
Service cost	$303	$290	$84	$79
Interest cost	602	632	131	136
Expected return on assets	(939)	(898)	(130)	(121)
Amortization of:				
Prior service cost (benefit)	1	—	(140)	(140)
Actuarial loss	472	455	50	46
Settlement charges	1	3	—	—
Net periodic benefit cost	$440	$482	$(5)	$—

(a) FitzPatrick net benefit costs are included for the period after the acquisition date of March 31, 2017.

The amounts below represent Exelon's, Generation's, ComEd's, PECO's, BGE's, BSC's, PHI's, Pepco's, DPL's, ACE's, and PHISCO's allocated portion of the pension and postretirement benefit plan costs. As a result of new pension guidance effective on January 1, 2018, certain balances have been reclassified on Exelon’s Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2017. The amounts below represent the Registrants’ as well as BSC's and PHISCO's pension and postretirement benefit plan net periodic benefit costs. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant and equipment, net, for the three and nine months ended September 30, 2018 and 2017, while the non-service cost components are included in Other, net and Regulatory assets for the three and nine months ended September 30, 2018 and in Other, net and Property, plant and equipment, net, for the three and nine months ended September 30, 2017. For the Registrants other than Exelon, the service cost and non-service cost components are included in Operating and maintenance expense and Property, plant and equipment, net on their consolidated financial statements for the three and nine months ended September 30, 2018 and 2017.

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Pension and Other Postretirement Benefit Costs	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Exelon[(a)(b)]	$145	$161	$435	$482
Generation[(b)]	50	57	151	170
ComEd	45	44	133	131
PECO	5	7	14	21
BGE	15	16	44	48
BSC[(c)]	13	13	42	40
PHI[(a)]	17	24	51	72
Pepco	3	6	10	19
DPL	2	3	5	10
ACE	3	3	10	10
PHISCO[(d)]	9	12	26	33

(a) Exelon reflects the consolidated pension and other postretirement benefit costs of Generation, ComEd, PECO, BGE, BSC, and PHI. PHI reflects the consolidated pension and other postretirement benefit costs of Pepco, DPL, ACE, and PHISCO.
(b) FitzPatrick net benefit costs are included for the period after the acquisition date of March 31, 2017.
(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, ACE or PHISCO amounts above.
(d) These amounts represent amounts billed to Pepco, DPL and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

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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 during the three and nine months ended September 30, 2018 and 2017, respectively.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Savings Plan Matching Contributions	2018	2017	2018	2017
Exelon[(a)(b)]	$ 44	$ 34	$ 126	$ 97
Generation[(b)]	23	14	65	42
ComEd	8	9	23	24
PECO	2	3	7	7
BGE	2	3	5	7
BSC[(c)]	5	2	16	7
PHI[(a)]	4	3	10	10
Pepco	1	1	2	3
DPL	1	1	2	2
ACE	1	—	2	1
PHISCO[(d)]	1	1	4	4

(a) Exelon reflects the consolidated savings plan matching contributions of Generation, ComEd, PECO, BGE, BSC, and PHI. PHI reflects the consolidated savings plan matching contributions of Pepco, DPL, ACE, and PHISCO.
(b) FitzPatrick net benefit costs are included for the period after the acquisition date of March 31, 2017.
(c) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, ACE or PHISCO amounts above.
(d) These amounts represent amounts billed to Pepco and DPL through intercompany allocations. These amounts are not included in Pepco or DPL amounts above.

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15. Changes in Accumulated Other Comprehensive Income (Exelon, Generation and PECO)
The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the nine months ended September 30, 2018 and 2017:

Nine Months Ended September 30, 2018	Gains (Losses) on Cash Flow Hedges	Unrealized gains (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates	Total
Exelon[a]						
Beginning balance	$ (14)	$ 10	$ (2,998) [d]	$ (23)	$ (1)	$ (3,026)
OCI before reclassifications	11	—	22	(4)	1	30
Amounts reclassified from AOCI[b]	1	—	136	—	—	137
Net current-period OCI	12	—	158	(4)	1	167
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(10) [c]	—	—	—	(10)
Ending balance	$ (2)	$ —	$ (2,840)	$ (27)	$ —	$ (2,869)
Generation[a]						
Beginning balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
OCI before reclassifications	11	—	—	(4)	1	8
Amounts reclassified from AOCI[b]	1	—	—	—	—	1
Net current-period OCI	12	—	—	(4)	1	9
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(3) [c]	—	—	—	(3)
Ending balance	$ (4)	$ —	$ —	$ (27)	$ —	$ (31)
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(1) [c]	—	—	—	(1)
Ending balance	$ —	$ —	$ —	$ —	$ —	$ —

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Nine Months Ended September 30, 2017	Gains (Losses) on Cash Flow Hedges	Unrealized gains (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments in Unconsolidated Affiliates	Total
Exelon[(a)]						
Beginning balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$(2,660)
OCI before reclassifications	2	2	(55)	7	7	(37)
Amounts reclassified from AOCI[(b)]	3	—	105	—	—	108
Net current-period OCI	5	2	50	7	7	71
Ending balance	$ (12)	$ 6	$ (2,560)	$ (23)	$ —	$(2,589)
Generation[(a)]						
Beginning balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$(54)
OCI before reclassifications	2	—	—	7	6	15
Amounts reclassified from AOCI[(b)]	3	—	—	—	—	3
Net current-period OCI	5	—	—	7	6	18
Ending balance	$ (14)	$ 2	$ —	$ (23)	$ (1)	$(36)
PECO[(a)]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[(b)]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$1

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) Exelon prospectively adopted the new standard Recognition and Measurement of Financial Assets and Liabilities. The standard was adopted as of January 1, 2018, which resulted in an increase to Retained earnings and Accumulated other comprehensive loss of $10 million, $3 million and $1 million for Exelon, Generation and PECO, respectively. The amounts reclassified related to Rabbi Trusts. See Note 2 — New Accounting Standards for additional information.
(d) Exelon early adopted the new standard Reclassification of Certain Tax Effects from AOCI. The standard was adopted retrospectively as of December 31, 2017, which resulted in an increase to Exelon's Retained earnings and Accumulated other comprehensive loss of $539 million, primarily related to deferred income taxes associated with Exelon's pension and OPEB obligations. See Note 2 — New Accounting Standards for additional information.

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ComEd, PECO, BGE, PHI, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three and nine months ended September 30, 2018 and 2017. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the three and nine months ended September 30, 2018 and 2017.

Three Months Ended September 30, 2018

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ —	$ —	Interest expense
	—	—	Total before tax
	—	—	Tax benefit
	$ —	$ —	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 23	$ —	
Actuarial losses[b]	(83)	—	
	(60)	—	Total before tax
	15	—	Tax benefit
	$ (45)	$ —	Net of tax
Total Reclassifications	$ (45)	$ —	Net of tax

Nine Months Ended September 30, 2018

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ (1)	$ (1)	Interest expense
	(1)	(1)	Total before tax
	—	—	Tax benefit
	$ (1)	$ (1)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 68	$ —	
Actuarial losses[b]	(251)	—	
	(183)	—	Total before tax
	47	—	Tax benefit
	$ (136)	$ —	Net of tax
Total Reclassifications	$ (137)	$ (1)	Net of tax

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Three Months Ended September 30, 2017

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ 2	$ 2	Interest expense
	2	2	Total before tax
	(1)	(1)	Tax expense
	$ 1	$ 1	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 23	$ —	
Actuarial losses[b]	(81)	—	
	(58)	—	Total before tax
	23	—	Tax benefit
	$ (35)	$ —	Net of tax
Total Reclassifications	$ (34)	$ 1	Net of tax

Nine Months Ended September 30, 2017

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ (5)	$ (5)	Interest expense
	(5)	(5)	Total before tax
	2	2	Tax benefit
	$ (3)	$ (3)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 69	$ —	
Actuarial losses[b]	(243)	—	
	(174)	—	Total before tax
	69	—	Tax benefit
	$ (105)	$ —	Net of tax
Total Reclassifications	$ (108)	$ (3)	Net of tax

(a) Amounts in parenthesis represent a decrease in AOCI.
(b) This AOCI component is included in the computation of net periodic pension and OPEB cost (see Note 14 — Retirement Benefits for additional information).

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The following table presents income tax benefit (expense) allocated to each component of other comprehensive income (loss) during the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$6	$9	$18	$27
Actuarial loss reclassified to periodic benefit cost	(21)	(32)	(65)	(96)
Pension and non-pension postretirement benefit plans valuation adjustment	(2)	—	(8)	2
Change in unrealized gains on cash flow hedges	—	—	(5)	(3)
Change in unrealized gains (losses) on investments in unconsolidated affiliates	—	1	(1)	(2)
Change in unrealized gains on marketable securities	—	—	—	(2)
Total	$(17)	$(22)	$(61)	$(74)
Generation				
Change in unrealized gains on cash flow hedges	$—	$—	$(4)	$(3)
Change in unrealized gains on investments in unconsolidated affiliates	—	—	(1)	(2)
Change in unrealized gains on marketable securities	—	—	—	(1)
Total	$—	$—	$(5)	$(6)

16. Earnings Per Share and Equity (Exelon)

Earnings per Share

Basic earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding, including the effect of issuing common stock assuming (i) stock options are exercised, and (ii) performance share awards and restricted stock awards are fully vested under the treasury stock method.

The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock awards on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Exelon				
Net income attributable to common shareholders	$733	$823	$1,858	$1,907
Weighted average common shares outstanding — basic	968	962	967	941
Assumed exercise and/or distributions of stock-based awards	2	3	2	2
Weighted average common shares outstanding — diluted	970	965	969	943

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The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 2 million and 3 million for the three and nine months ended September 30, 2018, respectively, and 7 million and 9 million for the three and nine months ended September 30, 2017, respectively. There were no equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the three and nine months ended September 30, 2018 and 2017. See Note 19 — Shareholders' Equity of the Exelon 2017 Form 10-K for additional information regarding the equity units.

Under share repurchase programs, 2 million shares of common stock are held as treasury stock with a cost of $123 million as of September 30, 2018.

17. Commitments and Contingencies (All Registrants)

The following is an update to the current status of commitments and contingencies set forth in Note 23 of the Exelon 2017 Form 10-K. See Note 4 — Mergers, Acquisitions and Dispositions of the Exelon 2017 Form 10-K for additional information on the PHI Merger commitments.

Commitments

PHI Merger Commitments (Exelon, PHI, Pepco, DPL and ACE)

The merger of Exelon and PHI was approved in Delaware, New Jersey, Maryland and the District of Columbia. Exelon and PHI agreed to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a “most favored nation” provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date and the remaining obligations as of September 30, 2018:

Description	Expected Payment Period	Exelon	PHI	Pepco	DPL	ACE
Rate credits	2016 - 2021	$ 259	$259	$ 91	$ 67	$101
Energy efficiency	2016 - 2021	122	—	—	—	—
Charitable contributions	2016 - 2026	50	50	28	12	10
Delivery system modernization	Q2 2017	22	—	—	—	—
Green sustainability fund	Q2 2017	14	—	—	—	—
Workforce development	2016 - 2020	17	—	—	—	—
Other		29	6	1	5	—
Total commitments		$ 513	$315	$ 120	$ 84	$111
Remaining commitments		$ 138	$94	$ 75	$ 12	$7

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are expected to be completed in 2018. These investments are expected to total approximately $137 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100 MWs of wind energy in

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PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions.

Pursuant to the various jurisdictions' merger approval conditions, over specified periods Pepco, DPL and ACE are not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process and have made other commitments regarding hiring and relocation of positions.

Constellation Merger Commitments (Exelon and Generation)

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to develop or assist in the development of 285-300 MWs of new generation. Exelon and Generation have incurred $458 million towards satisfying the commitment for new generation development in the State of Maryland, with 220 MW of new generation in operations to date and 10 MW of this commitment satisfied through a liquidated damages payment made in the fourth quarter of 2016. The remaining 55 MW is expected to be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, as of September 30, 2018 Exelon’s and Generation’s Consolidated Balance Sheets include a $50 million liability within Deferred credits and other liabilities for this remaining commitment, to be paid on or before January 15, 2023 unless the period is extended by consent of Exelon and the State of Maryland. See Note 23 - Commitments and Contingencies of the Exelon 2017 Form 10-K for additional information regarding the Constellation Merger Commitments.

Commercial Commitments (All Registrants)

The Registrants’ commercial commitments as of September 30, 2018, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Letters of credit (non-debt)[(a)]	$1,584	$ 1,565	$ 2	$ —	$ 3	$4	$ 4	$ —	$ —
Surety bonds[(b)]	1,402	1,201	9	9	25	65	32	4	3
Financing trust guarantees	378	—	200	178	—	—	—	—	—
Guaranteed lease residual values[(c)]	22	—	—	—	—	22	7	9	6
Total commercial commitments	$3,386	$ 2,766	$ 211	$ 187	$ 28	$91	$ 43	$ 13	$ 9

(a) Letters of credit (non-debt) - Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties. Includes letters of credits issued under credit facility agreements arranged at minority and community banks and nonrecourse debt letters of credits.

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

(c) 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 maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $60 million, $17 million of which is a guarantee by Pepco, $25 million by DPL and $17 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Nuclear Insurance (Exelon and Generation)

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of September 30, 2018, the current liability limit per incident is $13.1 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Changes to account for the effects of inflation occur at least once every five years with the last adjustment effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. Effective January 1, 2017, the required amount of nuclear energy liability insurance purchased is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool, as required by the Price Anderson-Act, which provides the additional $12.6 billion per incident in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Exelon's share of this secondary layer would be approximately $2.8 billion, however any amounts payable under this secondary layer would be capped at $420 million per year.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.1 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates 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. See Note 2 — Variable Interest Entities of the Exelon 2017 Form 10-K for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. In March 2018, NEIL declared a supplemental distribution. Generation's portion of the supplemental distribution declared by NEIL was $31 million and was recorded as a reduction to Operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income for the nine months ended September 30, 2018.

Premiums paid to NEIL by its members are also subject to a potential assessment for adverse loss experience in the form of a retrospective premium obligation. NEIL has never assessed this retrospective premium since its formation in 1973, and Generation cannot predict the level of future assessments if any. The current maximum aggregate annual retrospective premium obligation for Generation is approximately $345 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing

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of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery by Exelon will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon’s and Generation’s financial condition, results of operations and cash flows.

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 conditions, results of operations and cash flows.

MGP Sites (Exelon, ComEd, PECO, BGE, PHI and DPL)

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 identified 42 sites, 20 of which have been remediated and approved by the Illinois EPA or the U.S. EPA and 22 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 2023.
- PECO has identified 26 sites, 17 of which have been remediated in accordance with applicable PA DEP regulatory requirements and 9 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 2022.
- BGE has identified 13 sites, 9 of which have been remediated and approved by the MDE and 4 that require some level of remediation and/or ongoing activity. BGE expects the majority of the remediation at these sites to continue through at least 2019.
- DPL has identified 3 sites, for 2 of which remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control.

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The remaining site is 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. See Note 6 — Regulatory Matters for additional information regarding the associated regulatory assets. 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.

During the third quarter of 2018, the Utility Registrants completed an annual study of their future estimated MGP remediation requirements. The study resulted in a $48 million increase to the environmental liability and related regulatory asset for ComEd. The increase was primarily due to a revised closure strategy at one site, which resulted in an increase in the excavation area and depth of impacted soils from the site. The study did not result in a material change to the environmental liability for PECO, BGE, Pepco, DPL and ACE.

As of September 30, 2018 and December 31, 2017, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

September 30, 2018	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 486	$ 352
Generation	102	—
ComEd	323	321
PECO	28	27
BGE	6	4
PHI	27	—
Pepco	25	—
DPL	1	—
ACE	1	—

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December 31, 2017	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 466	$ 315
Generation	117	—
ComEd	285	283
PECO	30	28
BGE	5	4
PHI	29	—
Pepco	27	—
DPL	1	—
ACE	1	—

Solid and Hazardous Waste

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. On May 29, 2008, the EPA issued a Record of Decision (ROD) approving a landfill cover remediation approach. Generation had previously recorded an estimated liability for its anticipated share of a landfill cover remedy that was estimated to cost approximately $90 million in total. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study. This further analysis was focused on a partial excavation remedial option. The PRPs provided the final Remedial Investigation and Feasibility Study (RI/FS) to the EPA in January 2018, which formed the basis for EPA's final remedy selection, as discussed below. There are currently 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.

On September 27, 2018 the EPA issued its ROD Amendment for the selection of the final remedy for the West Lake Landfill Superfund site. The ROD modifies the EPA's previously proposed plan for partial excavation of the radiological materials by reducing the depths of the excavation. The ROD also allows for variation in depths of excavation depending on radiological concentrations. The EPA estimates that the ROD will result in a reduction of both radiological and non-radiological waste excavated, with corresponding reductions in the cost and schedule for the remedy. The next step is the negotiation of a Consent Agreement by the EPA with the PRPs to implement the ROD, a process that is expected to be completed in the first quarter of 2020. The estimated cost of the remedy, taking into account the current EPA technical requirements and the total costs expected to be incurred by the PRPs in fully executing the remedy, is approximately $280 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 for the entire remediation effort. 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 remediation 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 Generation’s associated allocable share could differ significantly once these uncertainties are resolved, which could have a material impact on Exelon's and Generation's future financial conditions, results of operations and cash flows.

On January 16, 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 RI/FS and reimbursement of EPA’s oversight costs. The purposes of this new RI/FS are to define the nature and extent of any groundwater contamination from the West Lake Landfill site, determine the potential risk posed to human health and the environment, and evaluate remedial alternatives. Generation estimates the undiscounted cost for the groundwater RI/FS for West Lake to be approximately $20 million and Generation 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 will be required and cannot estimate a reasonably possible range of loss for response costs beyond those associated with the RI/FS component. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Exelon’s and Generation’s future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action, and the work is expected to be completed in 2018. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill 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, Generation believes that the requirement to build a barrier wall is remote in light of other technologies that have been employed by the adjacent landfill owner. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the 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 on Exelon’s and Generation's financial conditions, results of operations and cash flows.

On August 8, 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 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. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million from all PRPs. The DOJ and the PRPs agreed to toll the statute of limitations until August 2019 so that settlement discussions could proceed. Generation has determined that a loss associated with this matter is probable under its

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indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above. Commencing in February 2012, a number of lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, as well as Cotter, which remains a defendant. The suits allege that individuals living in the North St. Louis area developed some form of cancer or other serious illness due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs are asserting public liability claims under the Price-Anderson Act. Their state law claims for negligence, strict liability, emotional distress, and medical monitoring have been dismissed. In the event of a finding of liability against Cotter, it is probable that Generation would be financially responsible due to its indemnification responsibilities of Cotter described above. The court has dismissed a number of the lawsuits as untimely, which has been upheld on appeal. Cotter and the remaining plaintiffs have engaged in settlement discussions pursuant to court-ordered mediation. During the second quarter of 2018, Generation determined a loss was probable based on the advancement of settlement proceedings and recorded an immaterial liability.

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. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. 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 Remediation Investigation (RI)/ Feasibility Study (FS) for the Benning Road site and an approximately 10 to 15-acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The Consent Decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site. Pursuant to Exelon's March 23, 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation.

Since 2013, Pepco and Pepco Energy Services (now Generation) have been performing RI work and have submitted multiple draft RI reports to the DOEE. Once the RI work is completed, Pepco and Generation will issue a draft "final" RI report for review and comment by DOEE and the public. Pepco and Generation will then proceed to develop an FS to evaluate possible remedial alternatives for submission to DOEE. The Court has established a schedule for completion of the RI and FS, and approval by the DOEE, by May 6, 2019.

Upon DOEE's approval of the final RI and FS Reports, Pepco and Generation will have satisfied their obligations under the Consent Decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision 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 RI/FS being performed by Pepco and Generation, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the

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Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. In March 2016, DOEE released a draft of the river-wide RI Report for public review and comment. 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. DOEE asked Pepco, along with parties responsible for other sites along the river, to participate in a "Consultative Working Group" to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning RI/FS. Pepco responded that it will participate in the Consultative Working Group, but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. In April 2018, DOEE released a draft remedial investigation report for public review and comment. Pepco submitted written comments to the draft RI and participated in a public hearing. Pepco continues outreach efforts as appropriate to the agencies, governmental officials, community organizations and other key stakeholders. In May 2018 the District of Columbia Council extended the deadline for completion of the Record of Decision from June 30, 2018 until December 31, 2019. An appropriate liability for Pepco's share of investigation costs has been accrued and is included in the table above. Although Pepco has determined that it is probable that costs for remediation will be incurred, Pepco cannot estimate the reasonably possible range of loss at this time and no liability has been accrued for those future costs. A draft Feasibility Study of potential remedies and their estimated costs is being prepared by the agencies and is expected to be released in early 2019, at which time Pepco will likely be in a better position to estimate the range of loss.

In addition to the activities associated with the remedial process outlined above, there is a complementary statutory program that requires an assessment to determine if any natural resources have been damaged as a result of the contamination that is being remediated, and, if so, that a plan be developed by the federal, state and local Trustees responsible for those resources to restore them to their condition before injury from the environmental contaminants. If natural resources are not restored, then compensation for the injury can be sought from the party responsible for the release of the contaminants. The assessment of Natural Resource Damages (NRD) typically takes place following cleanup because cleanups sometimes also effectively restore habitat. During the second quarter of 2018, Pepco became aware that the Trustees are in the beginning stages of this 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 it cannot reasonably estimate the range of loss.

Conectiv Energy Wholesale Power Generation Sites (Exelon, Generation, and PHI)

In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to $10 million. PHI indemnified Calpine for any ISRA compliance remediation costs in excess of $10 million. PHI estimated the costs of ISRA-required remediation activities at the nine generating facility sites located in New Jersey are in the range of approximately $7 million to $18 million and recorded a liability for its share of the estimated clean-up costs. Pursuant to Exelon's March 2016 acquisition of PHI, the Conectiv Energy legal entity was transferred to Generation and the liability for PHI's share of the estimated clean-up costs was also transferred to Generation and is included in the table above as a liability of Generation. The responsibility to indemnify Calpine is shared by PHI and Generation.

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Brandywine Fly Ash Disposal Site (Exelon, PHI and Pepco)

In February 2013, Pepco received a letter from the MDE requesting that Pepco investigate the extent of waste on a Pepco right-of-way that traverses the Brandywine fly ash disposal site in Brandywine, Prince George's County, Maryland, owned by NRG Energy, Inc. (as successor to GenOn MD Ash Management, LLC) (NRG). In July 2013, while reserving its rights and related defenses under a 2000 agreement covering the sale of this site, Pepco indicated its willingness to investigate the extent of, and propose an appropriate closure plan to address, ash on the right-of-way. Pepco submitted a schedule for development of a closure plan to MDE on September 30, 2013 and, by letter dated October 18, 2013, MDE approved the schedule.

Pepco has determined that a loss associated with this matter is probable and has recorded an estimated liability, which is included in the table above. Pepco believes that the costs incurred in this matter may be recoverable from NRG under the 2000 sale agreement but has not recorded an associated receivable for any potential recovery.

Litigation and Regulatory Matters

PHI Merger (Exelon and PHI)

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the Exelon and PHI merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC's order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Court of Appeals of Maryland, which is the highest court in Maryland. On June 21, 2017, the Court of Appeals granted discretionary review of the January 27, 2017 decision by the Maryland Court of Special Appeals. The Maryland Court of Appeals will review the OPC argument that the MDPSC did not properly consider the acquisition premium paid to PHI shareholders under Maryland's merger approval standard and the Sierra Club's argument that the merger would harm the renewable and distributed generation markets. The two lower courts examining these issues rejected these arguments, which Exelon believes are without merit. All briefs have been filed and oral arguments were presented to the court on October 10, 2017. On August 29, 2018, the Maryland Court of Appeals affirmed the MDPSC's May 2015 Order approving the merger of Exelon and PHI. This concluded the final legal challenge to the merger of Exelon and PHI.

Asbestos Personal Injury Claims (Exelon, Generation, PECO and ComEd)

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, 2018 and December 31, 2017, Generation had recorded estimated liabilities of approximately $80 million and $78 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2018, approximately $24 million of this amount related to 241 open claims presented to Generation, while the remaining $56 million is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, 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.

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There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material unfavorable impact on Exelon's, Generation's and PECO's financial conditions, results of operations and cash flows.

City of Everett Tax Increment Financing Agreement (Exelon and Generation)

On April 10, 2017, the City of Everett petitioned the Massachusetts Economic Assistance Coordinating Council (EACC) to revoke the 1999 tax increment financing agreement (TIF Agreement) relating to Mystic Units 8 and 9 on the grounds that the total investment in Mystic Units 8 and 9 materially deviates from the investment set forth in the TIF Agreement. On October 31, 2017, a three-member panel of the EACC conducted an administrative hearing on the City's petition. On November 30, 2017, the hearing panel issued a tentative decision denying the City's petition, finding that there was no material misrepresentation that would justify revocation of the TIF Agreement. On December 13, 2017, the tentative decision was adopted by the full EACC. On January 12, 2018, the City filed a complaint in Massachusetts Superior Court requesting, among other things, that the court set aside the EACC's decision, grant the City's request to decertify the Project and the TIF Agreement, and award the City damages for alleged underpaid taxes over the period of the TIF Agreement. Generation vigorously contested the City's claims before the EACC and will continue to do so in the Massachusetts Superior Court proceeding. Generation continues to believe that the City's claim lacks merit. Accordingly, Generation has not recorded a liability for payment resulting from such a revocation, nor can Generation estimate a reasonably possible range of loss, if any, associated with any such revocation. Further, it is reasonably possible that property taxes assessed in future periods, including those following the expiration of the current TIF Agreement in 2019, could be material to Generation's results of operations and cash flows.

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.

Income Taxes

See Note 12 — Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

18. Supplemental Financial Information (All Registrants)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three and nine months ended September 30, 2018 and 2017.

	Three Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$214	$ 214	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	58	58	—	—	—	—	—	—	—
Net unrealized (losses) gains on decommissioning trust funds									
Regulatory agreement units	(66)	(66)	—	—	—	—	—	—	—
Non-regulatory agreement units	72	72	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(9)	(9)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(110)	(110)	—	—	—	—	—	—	—
Total decommissioning-related activities	159	159	—	$ —	—	—	—	—	—
Investment income	9	5	—	—	—	2	1	1	—
Interest income related to uncertain income tax positions	1	—	—	—	—	—	—	—	—
AFUDC — Equity	16	—	4	1	5	6	6	—	—
Non-service net periodic benefit cost	(12)	—	—	—	—	—	—	—	—
Other	21	15	3	1	—	3	—	1	1
Other, net	$194	$ 179	$ 7	2	$ 5	$11	$ 7	$ 2	$ 1

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[a]									
Regulatory agreement units	$476	$ 476	$ —	$ —	$—	$—	$ —	$ —	$ —
Non-regulatory agreement units	257	257	—	—	—	—	—	—	—
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(335)	(335)	—	—	—	—	—	—	—
Non-regulatory agreement units	(143)	(143)	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(7)	(7)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(110)	(110)	—	—	—	—	—	—	—
Total decommissioning-related activities	138	138	—	—	—	—	—	—	—
Investment income	19	12	—	—	—	3	1	1	—
Interest income related to uncertain income tax positions	5	1	—	—	—	—	—	—	—
AFUDC — Equity	47	—	12	3	13	19	17	2	—
Non-service net periodic benefit cost	(33)	—	—	—	—	—	—	—	—
Other	36	13	9	1	1	11	5	4	2
Other, net	$212	$ 164	$ 21	$ 4	$ 14	$33	$ 23	$ 7	$ 2

	Three Months Ended September 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[a]									
Regulatory agreement units	$159	$ 159	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	59	59	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	44	44	—	—	—	—	—	—	—
Non-regulatory agreement units	111	111	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(4)	(4)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(161)	(161)	—	—	—	—	—	—	—
Total decommissioning-related activities	208	208	—	—	—	—	—	—	—
Investment income	2	1	—	—	—	1	1	—	—
Interest expense related to uncertain income tax positions	4	—	—	—	—	—	—	—	—
AFUDC — Equity	17	—	2	2	4	9	6	2	1
Non-service net periodic benefit cost	(27)	—	—	—	—	—	—	—	—
Other	6	—	3	—	—	3	—	2	—
Other, net	$210	$ 209	$ 5	$ 2	$ 4	$13	$ 7	$ 4	$ 1

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$439	$ 439	$ —	$ —	$—	$—	$ —	$—	$ —
Non-regulatory agreement units	165	165	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	253	253	—	—	—	—	—	—	—
Non-regulatory agreement units	347	347	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(5)	(5)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	(558)	(558)	—	—	—	—	—	—	—
Total decommissioning-related activities	641	641	—	—	—	—	—	—	—
Investment income	6	4	—	—	—	2	1	—	—
Interest income related to uncertain income tax positions	3	—	—	—	—	—	—	—	—
Penalty income related to uncertain income tax positions	2	—	—	—	—	—	—	—	—
AFUDC — Equity	51	—	6	6	12	27	17	5	5
Non-service net periodic benefit cost	(82)	—	—	—	—	—	—	—	—
Other	22	3	8	—	—	11	4	5	1
Other, net	$643	$ 648	$ 14	$ 6	$ 12	$40	$ 22	$ 10	$ 6

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 — Asset Retirement Obligations of the Exelon 2017 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

The following utility taxes are included in revenues and expenses for the three and nine months ended September 30, 2018 and 2017. Generation’s utility tax expense represents gross receipts tax related to its retail operations, and the Utility Registrants' utility tax expense 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 on the Registrants’ Consolidated Statements of Operations and Comprehensive Income.

	Three Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$253	$ 32	$ 67	$ 39	$ 23	$92	$ 87	$ 5	$ —

	Nine Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$705	$ 92	$ 188	$ 102	$ 70	$253	$ 238	$ 15	$ —

	Three Months Ended September 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$245	$ 35	$ 65	$ 35	$ 22	$88	$ 83	$ 5	$ —

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$682	$ 97	$ 181	$ 95	$ 69	$240	$226	$14	$ —

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the nine months ended September 30, 2018 and 2017.

	Nine Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[(a)]	$2,829	$ 1,347	$ 613	$ 204	$249	$355	$ 161	$97	$70
Amortization of regulatory assets[(a)]	412	—	83	20	109	200	125	38	37
Amortization of intangible assets, net[(a)]	43	36	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	8	8	—	—	—	—	—	—	—
Nuclear fuel[(c)]	852	852	—	—	—	—	—	—	—
ARO accretion[(d)]	367	365	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$4,511	$ 2,608	$ 696	$ 224	$358	$555	$ 286	$135	$107

	Nine Months Ended September 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[(a)]	$2,416	$ 1,010	$ 579	$ 194	$233	$342	$ 153	$92	$66
Amortization of regulatory assets[(a)]	355	—	52	19	115	169	89	32	47
Amortization of intangible assets, net[(a)]	43	36	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[(b)]	19	19	—	—	—	—	—	—	—
Nuclear fuel[(c)]	816	816	—	—	—	—	—	—	—
ARO accretion[(d)]	350	350	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$3,999	$ 2,231	$ 631	$ 213	$348	$511	$ 242	$124	$113

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$435	$ 151	$ 133	$ 14	$43	$51	$ 10	$5	$10
Loss (gain) from equity method investments	22	23	—	—	—	(1)	—	—	—
Provision for uncollectible accounts	133	38	30	25	6	32	12	6	14
Stock-based compensation costs	64	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(39)	(39)	—	—	—	—	—	—	—
Energy-related options[(b)]	4	4	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	6	—	2	—	—	3	1	1	1
Amortization of rate stabilization deferral	—	—	—	—	—	—	—	—	—
Amortization of debt fair value adjustment	(12)	(9)	—	—	—	(3)	—	—	—
Discrete impacts from EIMA and FEJA[(c)]	27	—	27	—	—	—	—	—	—
Amortization of debt costs	26	10	4	1	1	3	2	1	—
Provision for excess and obsolete inventory	15	13	2	—	—	—	—	—	—
Long-term incentive plan	84	—	—	—	—	—	—	—	—
Asset retirement costs	20	—	—	—	—	20	22	(1)	(1)
Other	19	(4)	(11)	1	(8)	4	(5)	4	—
Total other non-cash operating activities	$804	$ 187	$ 187	$ 41	$42	$109	$ 42	$16	$24
Non-cash investing and financing activities:									
(Decrease) increase in capital expenditures not paid	$(175)	$ (226)	$ (28)	$ 4	$44	$54	$ 15	$20	$16
Increase in PPE related to ARO update	67	47	4	—	1	15	12	2	1
Dividends on stock compensation	4	—	—	—	—	—	—	—	—
Acquisition of land	3	—	—	—	—	3	—	—	3

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$482	$ 170	$ 131	$21	$47	$72	$ 19	$10	$10
Loss from equity method investments	26	26	—	—	—	—	—	—	—
Provision for uncollectible accounts	103	31	25	17	4	26	11	1	14
Stock-based compensation costs	76	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(213)	(213)	—	—	—	—	—	—	—
Energy-related options[(b)]	15	15	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	7	—	3	1	—	3	1	1	1
Amortization of rate stabilization deferral	(7)	—	—	—	7	(14)	(12)	(2)	—
Amortization of debt fair value adjustment	(13)	(9)	—	—	—	(4)	—	—	—
Discrete impacts from EIMA and FEJA [(c)]	(61)	—	(61)	—	—	—	—	—	—
Amortization of debt costs	57	33	3	1	1	1	1	—	—
Provision for excess and obsolete inventory	52	50	1	—	—	1	—	1	—
Merger-related commitments[(d)]	—	—	—	—	—	(8)	(6)	(2)	—
Severance costs	33	25	—	—	—	3	—	—	—
Other	46	4	10	(2)	(7)	(14)	(6)	(3)	(4)
Total other non-cash operating activities	$603	$ 132	$ 112	$38	$52	$66	$ 8	$6	$21
Non-cash investing and financing activities:									
(Decrease) increase in capital expenditures not paid	$(101)	$ 20	$(79)	$(29)	$16	$(6)	$ 7	$14	$(18)
Fair value of pension obligation transferred in connection with the FitzPatrick acquisition	—	33	—	—	—	—	—	—	—
Decrease in PPE related to ARO update	(141)	(141)	—	—	—	—	—	—	—
Indemnification of like-kind exchange tax position[(e)]	—	—	21	—	—	—	—	—	—
Non-cash financing of capital projects	16	16	—	—	—	—	—	—	—
Dividends on stock compensation	5	—	—	—	—	—	—	—	—
Dissolution of financing trust due to long-term debt retirement	8	—	—	—	8	—	—	—	—
Fair value adjustment of long-term debt due to retirement	(5)	—	—	—	—	—	—	—	—

(a) Includes the elimination of decommissioning-related activities for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 — Asset Retirement Obligations of the Exelon 2017 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded in Operating revenues and expenses.
(c) Reflects the change in ComEd's distribution and energy efficiency formula rates. See Note 6 — Regulatory Matters for additional information.
(d) See Note 4 - Mergers, Acquisitions and Dispositions for additional information.
(e) See Note 12 - Income Taxes for additional information on the like-kind exchange tax position.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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.

September 30, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$1,918	$ 1,187	$ 124	$ 102	$113	$153	$ 12	$110	$ 11
Restricted cash	240	152	12	5	3	42	35	—	7
Restricted cash included in other long-term assets	163	—	144	—	—	19	—	—	19
Total cash, cash equivalents and restricted cash	$2,321	$ 1,339	$ 280	$ 107	$116	$214	$ 47	$110	$ 37

December 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$898	$ 416	$ 76	$ 271	$ 17	$30	$ 5	$ 2	$ 2
Restricted cash	207	138	5	4	1	42	35	—	6
Restricted cash included in other long-term assets	85	—	63	—	—	23	—	—	23
Total cash, cash equivalents and restricted cash	$1,190	$ 554	$ 144	$ 275	$ 18	$95	$ 40	$ 2	$ 31

September 30, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$1,203	$ 360	$ 257	$ 330	$ 29	$137	$ 117	$ 3	$ 5
Restricted cash	320	186	52	4	1	43	34	—	9
Restricted cash included in other long-term assets	22	—	—	—	—	22	—	—	22
Total cash, cash equivalents and restricted cash	$1,545	$ 546	$ 309	$ 334	$ 30	$202	$ 151	$ 3	$ 36

December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$ 635	$ 290	$ 56	$ 63	$ 23	$170	$ 9	$ 46	$101
Restricted cash	253	158	2	4	24	43	33	—	9
Restricted cash included in other long-term assets	26	—	—	—	3	23	—	—	23
Total cash, cash equivalents and restricted cash	$ 914	$ 448	$ 58	$ 67	$ 50	$236	$ 42	$ 46	$133

For additional information on restricted cash see Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants as of September 30, 2018 and December 31, 2017.

September 30, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$23,122 (a)	$ 12,753 (a)	$4,557	$3,521	$3,579	$759	$3,311	$1,315	$1,121
Accounts receivable:									
Allowance for uncollectible accounts	$354	$ 112	$93	$61	$22	$66	$25	$16	$25

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

December 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$21,064 (b)	$ 11,428 (b)	$4,269	$3,411	$3,405	$487	$3,177	$1,247	$1,066
Accounts receivable:									
Allowance for uncollectible accounts	$322	$ 114	$73	$56	$24	$55	$21	$16	$18

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $3,278 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $3,159 million.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $11 million as of September 30, 2018 and December 31, 2017. The allowance for uncollectible accounts balance associated with these receivables at September 30, 2018 and December 31, 2017 of $11 million consists of $3 million and $8 million for medium risk and high risk segments, respectively. See Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K for additional information regarding uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables.

19. Segment Information (All Registrants)

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants. Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL and ACE, and Generation’s six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as “Other Power Regions”, which includes activities in the South, West and Canada. 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 and return on equity.

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 six 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.

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- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO’s Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
- South represents operations in the FRCC, MISO’s Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation’s South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.
- 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.

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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, 2018 and 2017 is as follows:
Three Months Ended September 30, 2018 and 2017

	Generation[a]	ComEd	PECO	BGE	PHI	Other[b]	Intersegment Eliminations	Exelon
Operating revenues[c]:								
2018								
Competitive businesses electric revenues	$ 4,741	$—	—	$—	$—	$—	$ (306)	$4,435
Competitive businesses natural gas revenues	397	—	—	—	—	—	—	397
Competitive businesses other revenues	140	—	—	—	—	—	(1)	139
Rate-regulated electric revenues	—	1,598	700	645	1,334	—	(7)	4,270
Rate-regulated natural gas revenues	—	—	57	86	24	—	(5)	162
Shared service and other revenues	—	—	—	—	3	458	(461)	—
Total operating revenues	$ 5,278	$1,598	$757	$731	$1,361	$458	$ (780)	$9,403
2017								
Competitive businesses electric revenues	$ 4,041	$—	$—	$—	$—	$—	$ (295)	$3,746
Competitive businesses natural gas revenues	460	—	—	—	—	—	—	460
Competitive businesses other revenues	249	—	—	—	—	—	—	249
Rate-regulated electric revenues	—	1,571	662	658	1,280	—	(7)	4,164
Rate-regulated natural gas revenues	—	—	53	80	18	—	(2)	149
Shared service and other revenues	—	—	—	—	12	446	(458)	—
Total operating revenues	$ 4,750	$1,571	$715	$738	$1,310	$446	$ (762)	$8,768
Intersegment revenues[d]:								
2018	$ 308	$4	$2	$6	$3	$456	$ (779)	$—
2017	294	3	2	3	12	445	(759)	—
Net income (loss):								
2018	$ 300	$193	$126	$63	$187	$(69)	$ —	$800
2017	346	189	112	62	153	3	—	865
Total assets:								
September 30, 2018	$ 48,207	$31,119	$10,621	$9,541	$21,957	$8,418	$ (10,378)	$119,485
December 31, 2017	48,457	29,726	10,170	9,104	21,247	8,618	(10,552)	116,770

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the three months ended September 30, 2018 include revenue from sales to PECO of $35 million, sales to BGE of $69 million, sales to Pepco of $46 million, sales to DPL of $26 million and sales to ACE of $10 million in the Mid-Atlantic region, and sales to ComEd of $122 million in the Midwest region, which eliminate upon consolidation. For the three months ended September 30, 2017, intersegment revenues for Generation include revenue from sales to PECO of $31 million, sales to BGE of $98 million, sales to Pepco of $57 million, sales to DPL of $47 million and sales to ACE of $7 million in the Mid-Atlantic region, and sales to ComEd of $54 million in the Midwest region, which eliminate upon consolidation.

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

(c) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the three months ended September 30, 2018 and 2017.

(d) 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.

PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
Three Months Ended September 30, 2018						
Rate-regulated electric revenues	$628	$304	$406	$—	$ (4)	$1,334
Rate-regulated natural gas revenues	—	24	—	—	—	24
Shared service and other revenues	—	—	—	103	(100)	3
Total operating revenues	$628	$328	$406	$103	$ (104)	$1,361
Three Months Ended September 30, 2017						
Rate-regulated electric revenues	$604	$309	$370	$—	$ (3)	$1,280
Rate-regulated natural gas revenues	—	18	—	—	—	18
Shared service and other revenues	—	—	—	12	—	12
Total operating revenues	$604	$327	$370	$12	$ (3)	$1,310
Intersegment revenues:						
Three Months Ended September 30, 2018	$2	$2	$1	$103	$ (105)	$3
Three Months Ended September 30, 2017	1	2	—	13	(4)	12
Net income (loss):						
Three Months Ended September 30, 2018	$89	$33	$61	$1	$ 3	$187
Three Months Ended September 30, 2017	87	31	41	(18)	12	153
Total assets:						
September 30, 2018	$8,199	$4,601	$3,694	$10,763	$ (5,300)	$21,957
December 31, 2017	7,832	4,357	3,445	10,600	(4,987)	21,247

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(a)

Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the three months ended September 30, 2018 and 2017.

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

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 three months ended September 30, 2018 and 2017. 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Competitive Business Revenues (Generation):

	Three Months Ended September 30, 2018				
	Revenues from external parties[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$1,397	$ 52	$1,449	$ 7	$ 1,456
Midwest	1,095	26	1,121	(4)	1,117
New England	666	33	699	—	699
New York	475	(6)	469	—	469
ERCOT	156	289	445	(1)	444
Other Power Regions	293	265	558	(45)	513
Total Competitive Businesses Electric Revenues	4,082	659	4,741	(43)	4,698
Competitive Businesses Natural Gas Revenues	200	197	397	43	440
Competitive Businesses Other Revenues[c]	130	10	140	—	140
Total Generation Consolidated Operating Revenues	$4,412	$ 866	$5,278	$ —	$ 5,278

	Three Months Ended September 30, 2017				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$1,397	$ 24	$1,421	$ 11	$ 1,432
Midwest	982	67	1,049	(11)	1,038
New England	504	(22)	482	(1)	481
New York	454	(21)	433	(6)	427
ERCOT	164	144	308	6	314
Other Power Regions	167	181	348	(13)	335
Total Competitive Businesses Electric Revenues	3,668	373	4,041	(14)	4,027
Competitive Businesses Natural Gas Revenues	226	234	460	20	480
Competitive Businesses Other Revenues[c]	207	42	249	(6)	243
Total Generation Consolidated Operating Revenues	$4,101	$ 649	$4,750	$ —	$ 4,750

(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 a $13 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the three months ended September 30, 2017, unrealized mark-to-market gains of $6 million and $52 million for the three months ended September 30, 2018 and 2017, respectively, and elimination of intersegment revenues.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Revenues net of purchased power and fuel expense (Generation):

	Three Months Ended September 30, 2018			Three Months Ended September 30, 2017		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$746	$ 17	$763	$817	$ 38	$855
Midwest	763	5	768	697	—	697
New England	83	(2)	81	151	(6)	145
New York	290	2	292	295	—	295
ERCOT	161	(63)	98	229	(111)	118
Other Power Regions	143	(44)	99	118	(50)	68
Total Revenues net of purchased power and fuel for Reportable Segments	2,186	(85)	2,101	2,307	(129)	2,178
Other[b]	112	85	197	112	129	241
Total Generation Revenues net of purchased power and fuel expense	$2,298	$ —	$2,298	$2,419	$ —	$2,419

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(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 a $19 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the three months ended September 30, 2017, unrealized mark-to-market gains of $71 million and $73 million for the three months ended September 30, 2018 and 2017, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 - Early Plant Retirements of $18 million and $6 million decrease to revenue net of purchased power and fuel expense for the three months ended September 30, 2018, and 2017, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

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

	Three Months Ended September 30, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$861	$ 458	$366	$726	$306	$180	$240
Small commercial & industrial	391	108	68	140	39	48	53
Large commercial & industrial	131	64	117	303	230	25	48
Public authorities & electric railroads	11	7	7	14	8	3	3
Other[(a)]	212	59	91	156	47	47	63
Total rate-regulated electric revenues[(b)]	1,606	696	649	1,339	630	303	407
Rate-regulated natural gas revenues							
Residential	—	36	46	8	—	8	—
Small commercial & industrial	—	15	8	5	—	5	—
Large commercial & industrial	—	—	17	2	—	2	—
Transportation	—	5	—	3	—	3	—
Other[(c)]	—	1	12	6	—	6	—
Total rate-regulated natural gas revenues[(d)]	—	57	83	24	—	24	—
Total rate-regulated revenues from contracts with customers	1,606	753	732	1,363	630	327	407
Other revenues							
Revenues from alternative revenue programs	(15)	1	(6)	(5)	(4)	—	(1)
Other rate-regulated electric revenues[(e)]	7	3	4	3	2	1	—
Other rate-regulated natural gas revenues[(e)]	—	—	1	—	—	—	—
Total other revenues	(8)	4	(1)	(2)	(2)	1	(1)
Total rate-regulated revenues for reportable segments	$1,598	$ 757	$731	$1,361	$628	$328	$406

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Three Months Ended September 30, 2017						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$816	$ 434	$352	$687	$ 291	$185	$211
Small commercial & industrial	366	106	65	140	37	50	53
Large commercial & industrial	119	59	114	288	211	28	49
Public authorities & electric railroads	11	7	8	14	8	3	3
Other[(a)]	235	53	85	147	52	43	54
Total rate-regulated electric revenues[(b)]	1,547	659	624	1,276	599	309	370
Rate-regulated natural gas revenues							
Residential	—	33	44	8	—	8	—
Small commercial & industrial	—	14	8	3	—	3	—
Large commercial & industrial	—	—	19	1	—	1	—
Transportation	—	5	—	3	—	3	—
Other[(c)]	—	1	3	3	—	3	—
Total rate-regulated natural gas revenues[(d)]	—	53	74	18	—	18	—
Total rate-regulated revenues from contracts with customers	1,547	712	698	1,294	599	327	370
Other revenues							
Revenues from alternative revenue programs	16	—	36	2	3	(1)	—
Other rate-regulated electric revenues[(e)]	8	3	3	3	2	1	—
Other rate-regulated natural gas revenues[(e)]	—	—	1	—	—	—	—
Other revenues[(f)]	—	—	—	11	—	—	—
Total other revenues	24	3	40	16	5	—	—
Total rate-regulated revenues for reportable segments	$1,571	$ 715	$738	$1,310	$ 604	$327	$370

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(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates of $4 million, $2 million, $1 million, $3 million, $2 million, $2 million and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the three months ended September 30, 2018 and $3 million, $1 million, $1 million, $1 million $1 million, $2 million and less than $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the three months ended September 30, 2017.
(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates of less than $1 million and $5 million at PECO and BGE, respectively, for the three months ended September 30, 2018 and less than $1 million and $2 million at PECO and BGE, respectively, for the three months ended September 30, 2017.
(e) Includes late payment charge revenues.
(f) Includes operating revenues from affiliates of $11 million at PHI for the three months ended September 30, 2017.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Nine Months Ended September 30, 2018 and 2017

	Generation[(a)]	ComEd	PECO	BGE	PHI	Other[(b)]	Intersegment Eliminations	Exelon
Operating revenues[(c)]:								
2018								
Competitive businesses electric revenues	$ 13,190	$—	$—	$—	$—	$—	$ (969)	$12,221
Competitive businesses natural gas revenues	1,839	—	—	—	—	—	(8)	1,831
Competitive businesses other revenues	339	—	—	—	—	—	(4)	335
Rate-regulated electric revenues	—	4,508	1,893	1,850	3,549	—	(34)	11,766
Rate-regulated natural gas revenues	—	—	382	519	129	—	(13)	1,017
Shared service and other revenues	—	—	—	—	10	1,398	(1,408)	—
Total operating revenues	$ 15,368	$4,508	$2,275	$2,369	$3,688	$1,398	$ (2,436)	$27,170
2017								
Competitive businesses electric revenues	$ 11,514	$—	$—	$—	$—	$—	$ (888)	$10,626
Competitive businesses natural gas revenues	1,807	—	—	—	—	—	—	1,807
Competitive businesses other revenues	522	—	—	—	—	—	—	522
Rate-regulated electric revenues	—	4,227	1,802	1,895	3,417	—	(23)	11,318
Rate-regulated natural gas revenues	—	—	339	468	105	—	(6)	906
Shared service and other revenues	—	—	—	—	35	1,316	(1,350)	1
Total operating revenues	$ 13,843	$4,227	$2,141	$2,363	$3,557	$1,316	$ (2,267)	$25,180
Intersegment revenues[(d)]:								
2018	$ 981	$23	$5	$18	$11	$1,392	$ (2,430)	$—
2017	888	12	5	12	35	1,312	(2,262)	2
Net income (loss):								
2018	$ 667	$523	$336	$242	$336	$(125)	$ —	$1,979
2017	508	447	327	231	359	58	(2)	1,928

(a) Generation includes the six reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the nine months ended September 30, 2018 include revenue from sales to PECO of $97 million, sales to BGE of $198 million, sales to Pepco of $143 million, sales to DPL of $103 million and sales to ACE of $21 million in the Mid-Atlantic region, and sales to ComEd of $419 million in the Midwest region, which eliminate upon consolidation. For the nine months ended September 30, 2017, intersegment revenues for Generation include revenue from sales to PECO of $111 million, sales to BGE of $330 million, sales to Pepco of $209 million, sales to DPL of $138 million and sales to ACE of $23 million in the Mid-Atlantic region, and sales to ComEd of $77 million in the Midwest region, which eliminate upon consolidation.

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

(c) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the nine months ended September 30, 2018 and 2017.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

(d) 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.

PHI:

	Pepco	DPL	ACE	Other[b]	Intersegment Eliminations	PHI
Operating revenues[a]:						
Nine Months Ended September 30, 2018						
Rate-regulated electric revenues	$1,708	$872	$981	$ —	$ (12)	$3,549
Rate-regulated natural gas revenues	—	129	—	—	—	129
Shared service and other revenues	—	—	—	326	(316)	10
Total operating revenues	$1,708	$1,001	$981	$ 326	$ (328)	$3,688
Nine Months Ended September 30, 2017						
Rate-regulated electric revenues	$1,649	$866	$915	$ —	$ (13)	$3,417
Rate-regulated natural gas revenues	—	105	—	—	—	105
Shared service and other revenues	—	—	—	37	(2)	35
Total operating revenues	$1,649	$971	$915	$ 37	$ (15)	$3,557
Intersegment revenues:						
Nine Months Ended September 30, 2018	$5	$6	$2	$ 325	$ (327)	$11
Nine Months Ended September 30, 2017	4	6	2	37	(14)	35
Net income (loss):						
Nine Months Ended September 30, 2018	$174	$90	$76	$ (15)	$ 11	$336
Nine Months Ended September 30, 2017	188	107	77	(48)	35	359

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 18 — Supplemental Financial Information for total utility taxes for the nine months ended September 30, 2018 and 2017.

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

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 nine months ended September 30, 2018 and 2017. 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Competitive Business Revenues (Generation):

	Nine Months Ended September 30, 2018				
	Revenues from external parties[a]				
	Contracts with customers	Other[b]	Total	Intersegment Revenues	Total Revenues
Mid-Atlantic	$3,971	$191	$4,162	$ 17	$ 4,179
Midwest	3,432	169	3,601	(8)	3,593
New England	1,943	87	2,030	(4)	2,026
New York	1,305	(37)	1,268	1	1,269
ERCOT	470	459	929	1	930
Other Power Regions	713	487	1,200	(112)	1,088
Total Competitive Businesses Electric Revenues	11,834	1,356	13,190	(105)	13,085
Competitive Businesses Natural Gas Revenues	1,016	823	1,839	105	1,944
Competitive Businesses Other Revenues[c]	385	(46)	339	—	339
Total Generation Consolidated Operating Revenues	$13,235	$2,133	$15,368	$ —	$ 15,368

	Nine Months Ended September 30, 2017				
	Revenues from external customers[a]				
	Contracts with customers	Other[b]	Total	Intersegment revenues	Total Revenues
Mid-Atlantic	$4,260	$(53)	$4,207	$ 15	$ 4,222
Midwest	2,948	210	3,158	(17)	3,141
New England	1,555	(86)	1,469	(8)	1,461
New York	1,161	(37)	1,124	(14)	1,110
ERCOT	520	229	749	4	753
Other Power Regions	439	368	807	(28)	779
Total Competitive Businesses Electric Revenues	10,883	631	11,514	(48)	11,466
Competitive Businesses Natural Gas Revenues	1,237	570	1,807	52	1,859
Competitive Businesses Other Revenues[c]	588	(66)	522	(4)	518
Total Generation Consolidated Operating Revenues	$12,708	$1,135	$13,843	$ —	$ 13,843

(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 a $30 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the nine months ended September 30, 2017, unrealized mark-to-market losses of $96 million and $47 million for the nine months ended September 30, 2018 and 2017, respectively, and elimination of intersegment revenues.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Revenues net of purchased power and fuel expense (Generation):

	Nine Months Ended September 30, 2018			Nine Months Ended September 30, 2017		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$2,303	$ 45	$2,348	$2,330	$ 81	$2,411
Midwest	2,381	19	2,400	2,129	11	2,140
New England	310	(12)	298	423	(20)	403
New York	832	9	841	708	(1)	707
ERCOT	396	(180)	216	446	(188)	258
Other Power Regions	430	(121)	309	359	(139)	220
Total Revenues net of purchased power and fuel expense for Reportable Segments	6,652	(240)	6,412	6,395	(256)	6,139
Other[b]	164	240	404	162	256	418
Total Generation Revenues net of purchased power and fuel expense	$6,816	$ —	$6,816	$6,557	$ —	$6,557

(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 a $41 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the nine months ended September 30, 2017, unrealized mark-to-market losses of $104 million and $161 million for the nine months ended September 30, 2018 and 2017, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 - Early Plant Retirements of $53 million and $8 million decrease to revenue net of purchased power and fuel expense for the nine months ended September 30, 2018 and 2017, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

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

	Nine Months Ended September 30, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$2,277	$1,199	$1,054	$1,839	$792	$513	$534
Small commercial & industrial	1,132	306	196	370	104	138	128
Large commercial & industrial	411	174	325	845	632	74	139
Public authorities & electric railroads	36	21	21	44	24	10	10
Other[(a)]	656	181	246	446	145	129	174
Total rate-regulated electric revenues[(b)]	4,512	1,881	1,842	3,544	1,697	864	985
Rate-regulated natural gas revenues							
Residential	—	259	345	68	—	68	—
Small commercial & industrial	—	102	55	31	—	31	—
Large commercial & industrial	—	1	88	7	—	7	—
Transportation	—	16	—	12	—	12	—
Other[(c)]	—	4	49	11	—	11	—
Total rate-regulated natural gas revenues[(d)]	—	382	537	129	—	129	—
Total rate-regulated revenues from contracts with customers	4,512	2,263	2,379	3,673	1,697	993	985
Other revenues							
Revenues from alternative revenue programs	(27)	2	(23)	7	6	5	(4)
Other rate-regulated electric revenues[(e)]	23	10	10	8	5	3	—
Other rate-regulated natural gas revenues[(e)]	—	—	3	—	—	—	—
Total other revenues	(4)	12	(10)	15	11	8	(4)
Total rate-regulated revenues for reportable segments	$4,508	$2,275	$2,369	$3,688	$1,708	$1,001	$981

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

	Nine Months Ended September 30, 2017						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$2,071	$1,147	$1,038	$1,740	$751	$505	$484
Small commercial & industrial	1,035	303	193	373	105	139	129
Large commercial & industrial	346	168	329	814	593	78	143
Public authorities & electric railroads	33	23	23	45	24	11	10
Other[(a)]	671	151	222	398	148	121	140
Total rate-regulated electric revenues[(b)]	4,156	1,792	1,805	3,370	1,621	854	906
Rate-regulated natural gas revenues							
Residential	—	225	289	57	—	57	—
Small commercial & industrial	—	90	51	25	—	25	—
Large commercial & industrial	—	—	82	5	—	5	—
Transportation	—	16	—	11	—	11	—
Other[(c)]	—	8	20	7	—	7	—
Total rate-regulated natural gas revenues[(d)]	—	339	442	105	—	105	—
Total rate-regulated revenues from contracts with customers	4,156	2,131	2,247	3,475	1,621	959	906
Other revenues							
Revenues from alternative revenue programs	48	—	102	41	23	9	9
Other rate-regulated electric revenues[(e)]	23	10	11	8	5	3	—
Other rate-regulated natural gas revenues[(e)]	—	—	3	—	—	—	—
Other revenues[(f)]	—	—	—	33	—	—	—
Total other revenues	71	10	116	82	28	12	9
Total rate-regulated revenues for reportable segments	$4,227	$2,141	$2,363	$3,557	$1,649	$971	$915

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates of $23 million, $5 million, $5 million, $11 million, $5 million, $6 million and $2 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the nine months ended September 30, 2018 and $12 million, $4 million, $5 million, $2 million, $4 million, $6 million and $2 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the nine months ended September 30, 2017.
(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates of less than $1 million and $13 million at PECO and BGE, respectively, for the nine months ended September 30, 2018 and less than $1 million and $7 million at PECO and BGE, respectively, for the nine months ended September 30, 2017.
(e) Includes late payment charge revenues.
(f) Includes operating revenues from affiliates of $33 million at PHI for the nine months ended September 30, 2017.

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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, a utility services holding company, operates through the following principal subsidiaries:

- Generation, whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services.
- ComEd, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.
- PECO, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- BGE, whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore.
- Pepco, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.
- DPL, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.
- ACE, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.
Exelon has twelve reportable segments consisting of Generation's six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.
Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and

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supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs income from various investment and financing activities.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHISCO and the participating operating subsidiaries.

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.

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Financial Results of Operations

GAAP Results of Operations

The following tables set forth Exelon's GAAP consolidated results of operations for the three and nine months ended September 30, 2018 compared to the same period in 2017. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30, 2018							2017	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$5,278	$1,598	$757	$731	$1,361	$(322)	$9,403	$8,768	$ 635
Purchased power and fuel expense	2,980	619	263	272	509	(311)	4,332	3,542	(790)
Revenue net of purchased power and fuel expense[(a)]	2,298	979	494	459	852	(11)	5,071	5,226	(155)
Other operating expenses									
Operating and maintenance	1,370	337	219	182	292	(54)	2,346	2,275	(71)
Depreciation and amortization	468	237	75	110	192	23	1,105	1,002	(103)
Taxes other than income	143	82	46	64	123	11	469	456	(13)
Total other operating expenses	1,981	656	340	356	607	(20)	3,920	3,733	(187)
(Loss) gain on sales of assets and businesses	(6)	—	—	—	—	1	(5)	(1)	(4)
Bargain purchase gain	—	—	—	—	—	—	—	7	(7)
Operating income	311	323	154	103	245	10	1,146	1,499	(353)
Other income and (deductions)									
Interest expense, net	(101)	(85)	(32)	(27)	(65)	(83)	(393)	(386)	(7)
Other, net	179	7	2	5	11	(10)	194	210	(16)
Total other income and (deductions)	78	(78)	(30)	(22)	(54)	(93)	(199)	(176)	(23)
Income (loss) before income taxes	389	245	124	81	191	(83)	947	1,323	(376)
Income taxes	78	52	(2)	18	4	(13)	137	451	314
Equity in (losses) earnings of unconsolidated affiliates	(11)	—	—	—	—	1	(10)	(7)	(3)
Net income (loss)	300	193	126	63	187	(69)	800	865	(65)
Net income attributable to noncontrolling interests	66	—	—	—	—	1	67	42	(25)
Net income (loss) attributable to common shareholders	$234	$193	$126	$63	$187	$(70)	$733	$823	$ (90)

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	Nine Months Ended September 30,								Favorable
	2018							2017	(Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$15,368	$4,508	$2,275	$2,369	$3,688	$(1,038)	$27,170	$25,180	$ 1,990
Purchased power and fuel expense	8,552	1,702	818	881	1,410	(989)	12,374	10,527	(1,847)
Revenue net of purchased power and fuel expense[(a)]	6,816	2,806	1,457	1,488	2,278	(49)	14,796	14,653	143
Other operating expenses									
Operating and maintenance	4,126	974	686	578	857	(185)	7,036	7,658	622
Depreciation and amortization	1,383	696	224	358	555	68	3,284	2,814	(470)
Taxes other than income	414	238	125	188	343	34	1,342	1,313	(29)
Total other operating expenses	5,923	1,908	1,035	1,124	1,755	(83)	11,662	11,785	123
Gain on sales of assets and businesses	48	5	1	1	—	—	55	4	51
Bargain purchase gain	—	—	—	—	—	—	—	233	(233)
Operating income	941	903	423	365	523	34	3,189	3,105	84
Other income and (deductions)									
Interest expense, net	(305)	(261)	(96)	(78)	(193)	(205)	(1,138)	(1,194)	56
Other, net	164	21	4	14	33	(24)	212	643	(431)
Total other income and (deductions)	(141)	(240)	(92)	(64)	(160)	(229)	(926)	(551)	(375)
Income (loss) before income taxes	800	663	331	301	363	(195)	2,263	2,554	(291)
Income taxes	110	140	(5)	59	28	(70)	262	601	339
Equity in (losses) earnings of unconsolidated affiliates	(23)	—	—	—	1	—	(22)	(25)	3
Net income (loss)	667	523	336	242	336	(125)	1,979	1,928	51
Net income attributable to noncontrolling interests	120	—	—	—	—	1	121	21	(100)
Net income (loss) attributable to common shareholders	$547	$523	$336	$242	$336	$(126)	$1,858	$1,907	$ (49)

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate their operational performance. Revenues net of purchased power and fuel expense 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.

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Exelon's Net income attributable to common shareholders was $733 million for the three months ended September 30, 2018 as compared to $823 million for the three months ended September 30, 2017, and diluted earnings per average common share were $0.76 for the three months ended September 30, 2018 as compared to $0.85 for the three months ended September 30, 2017.

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Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $155 million for the three months ended September 30, 2018 compared to the same period in 2017 primarily due to the following factors:

- Decrease of $121 million at Generation primarily due to the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower realized energy prices, lower energy efficiency revenues and decreased revenues related to the sale of Generation's electrical contracting business in 2018 and increased nuclear outage days, partially offset by the impact of Illinois ZES and increased capacity prices;
- Decrease of $113 million across all Utility Registrants, primarily reflecting lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates, partially offset by regulatory rate increases at ComEd, Pepco, DPL and ACE; and
- Increase of $58 million at PECO, DPL and ACE primarily due to favorable weather conditions and volumes within their respective service territories.

Operating and maintenance expense increased by $71 million for the three months ended September 30, 2018 as compared to the same period in 2017 primarily due to the following factors:

- Increase of $84 million at Generation due to a charge associated with a remeasurement of the Oyster Creek ARO;
- Increase of $40 million at Generation due to higher nuclear refueling outage costs;
- Increase of $22 million at Pepco due to a charge associated with a remeasurement of the Buzzard Point ARO; and
- Decrease of $50 million at Generation in labor, contracting and materials expense due to decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.

Depreciation and amortization expense increased by $103 million for the three months ended September 30, 2018 as compared to the same period in 2017 primarily due to ongoing capital expenditures across all operating companies, accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities, increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues), partially offset by certain regulatory assets that became fully amortized as of December 31, 2017 for BGE.

Other, net decreased by $16 million primarily due to lower net unrealized and realized gains on NDT funds at Generation for the three months ended September 30, 2018 compared to the same period in 2017.

Exelon’s effective income tax rates for the three months ended September 30, 2018 and 2017 were 14.5% and 34.1%, respectively. The decrease in the effective income tax rate for the three months ended September 30, 2018 compared to the same period in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA at all Registrants, which is predominantly offset in Operating revenues at the Utility Registrants for the anticipated pass back of the tax savings through customer rates. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on TCJA's impact on regulatory proceedings.

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Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Exelon's Net income attributable to common shareholders was $1,858 million for the nine months ended September 30, 2018 compared to $1,907 million for the nine months ended September 30, 2017, and diluted earnings per average common share were $1.92 for the nine months ended September 30, 2018 compared to $2.02 for the nine months ended September 30, 2017.

Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $143 million for the nine months ended September 30, 2018 as compared to the same period in 2017. The year-over-year increase in Revenue net of purchased power and fuel expense was primarily due to the following factors:

- Increase of $202 million at Generation primarily due to impact of the New York CES and Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, the acquisition of the FitzPatrick nuclear facility and decreased nuclear outage days, the addition of two combined-cycle gas turbines in Texas and the impacts of Generation's natural gas portfolio, partially offset by lower realized energy prices, the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower energy efficiency revenues and decreased revenues related to the sale of Generation's electrical contracting business in 2018;
- Increase of $57 million at Generation due to lower mark-to-market losses;
- Increase of $132 million at PECO, DPL and ACE primarily due to favorable weather conditions and volumes within their respective service territories;
- Increase of $33 million due to higher mutual assistance revenues across all Utility Registrants, primarily at ComEd;
- Decrease of $95 million at ComEd primarily due to lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA; and
- Decrease of $274 million in electric and gas revenues across all Utility Registrants, primarily reflecting lower revenues resulting from the anticipated pass back of TCJA tax savings through customer rates, partially offset by higher utility revenues due to regulatory rate increases at ComEd, BGE, Pepco, DPL and ACE.

Operating and maintenance expense decreased by $622 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to the following factors:

- Decrease of $411 million at Generation due to long-lived asset impairments primarily related to the EGTP assets held for sale in 2017;
- Decrease of $163 million at Generation in labor, contracting and materials expense due to decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.
- Decrease of $95 million at ComEd primarily due to the change to defer and recover over time energy efficiency costs pursuant to FEJA;
- Decrease of $66 million at Generation due to lower merger-related costs;
- Decrease of $56 million at Generation due to lower nuclear refueling outage costs;
- Decrease of $32 million due to a supplemental NEIL insurance distribution at Generation;

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- Increase of $47 million due to higher one-time charges related to Generation's decision to early retire the Oyster Creek nuclear facility in 2018, including a remeasurement to the ARO, compared to one-time charges related to Generation’s decision to early retire the TMI nuclear facility in 2017;
- Increase of $33 million due to higher mutual assistance expenses across all Utility Registrants, primarily at ComEd;
- Increase of $97 million at PECO and BGE due to increased storm costs; and
- Increase of $22 million at Pepco due to a charge associated with a remeasurement of the Buzzard Point ARO.

Depreciation and amortization expense increased by $470 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to increased depreciation expense as a result of ongoing capital expenditures across all operating companies, accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities, increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues), partially offset by certain regulatory assets that became fully amortized as of December 31, 2017 for BGE.

Taxes other than income increased due to increased gross receipts tax accruals at PECO and Pepco for the nine months ended September 30, 2018 compared to the same period in 2017.

Gain on sales of assets and businesses increased by $51 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to Generation's sale of its electrical contracting business.

Bargain purchase gain decreased by $233 million due to the gain associated with the FitzPatrick acquisition in the first quarter of 2017.

Interest expense, net decreased by $56 million due to retirement of long-term debt.

Other, net decreased by $431 million primarily due to lower net unrealized and realized gains on NDT funds at Generation for the nine months ended September 30, 2018 compared to the same period in 2017.

Exelon’s effective income tax rates for the nine months ended September 30, 2018 and 2017 were 11.6% and 23.5%, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2018 compared to the same period in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA at all Registrants, which is offset in Operating revenues at the Utility Registrants for the anticipated pass back of the tax savings through customer rates. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on TCJA's impact on regulatory proceedings.

For additional information regarding the financial results for the three and nine months ended September 30, 2018, including explanation of the non-GAAP measure Revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Registrant below.

Adjusted (non-GAAP) Operating Earnings

Exelon’s adjusted (non-GAAP) operating earnings for the three months ended September 30, 2018 were $856 million, or $0.88 per diluted share, compared with adjusted (non-GAAP) operating earnings

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of $820 million, or $0.85 per diluted share for the same period in 2017. Exelon's adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2018 were $2,467 million, or $2.55 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,943 million, or $2.06 per diluted share for the same period in 2017. 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 period-over-period 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.

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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, 2018 compared to the same period in 2017.

(All amounts in millions after tax)	Three Months Ended September 30, 2018		2017	
		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$733	$ 0.76	$823	$ 0.85
Mark-to-Market Impact of Economic Hedging Activities[a] (net of taxes of $20 and $29, respectively)	(55)	(0.06)	(45)	(0.05)
Unrealized Gains Related to NDT Fund Investments[b] (net of taxes of $4 and $51, respectively)	(53)	(0.06)	(67)	(0.07)
Amortization of Commodity Contract Intangibles[c] (net of taxes of $0 and $8, respectively)	—	—	12	0.01
Merger and Integration Costs[d] (net of taxes of $0 and $1, respectively)	—	—	(1)	—
Long-Lived Asset Impairments[f] (net of taxes of $2 and $16, respectively)	6	0.01	24	0.03
Plant Retirements and Divestitures[g] (net of taxes of $70 and $47, respectively)	202	0.21	71	0.08
Cost Management Program[h] (net of taxes of $4 and $8, respectively)	13	0.01	13	0.01
Bargain Purchase Gain[i] (net of taxes of $0 and $0, respectively)	—	—	(7)	(0.01)
Asset Retirement Obligation[n] (net of taxes of $6 and $1, respectively)	16	0.02	(2)	—
Change in Environmental Liabilities (net of taxes of $3 and $0, respectively)	(9)	(0.01)	—	—
Reassessment of Deferred Income Taxes[k] (entire amount represents tax expense)	(18)	(0.02)	(21)	(0.02)
Noncontrolling Interests[m] (net of taxes of $4 and $4, respectively)	21	0.02	20	0.02
Adjusted (non-GAAP) Operating Earnings	$856	$ 0.88	$820	$ 0.85

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(All amounts in millions after tax)	Nine Months Ended September 30, 2018	Earnings per Diluted Share	2017	Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,858	$ 1.92	$1,907	$ 2.02
Mark-to-Market Impact of Economic Hedging Activities[(a)] (net of taxes of $26 and $62, respectively)	74	0.08	97	0.10
Unrealized Losses (Gains) Related to NDT Fund Investments[(b)] (net of taxes of $118 and $181, respectively)	94	0.10	(211)	(0.22)
Amortization of Commodity Contract Intangibles[(c)] (net of taxes of $0 and $17, respectively)	—	—	27	0.03
Merger and Integration Costs[(d)] (net of taxes of $1 and $24, respectively)	5	—	39	0.04
Merger Commitments[(e)] (net of taxes of $0 and $137, respectively)	—	—	(137)	(0.15)
Long-Lived Asset Impairments[(f)] (net of taxes of $13 and $188, respectively)	36	0.04	293	0.31
Plant Retirements and Divestitures[(g)] (net of taxes of $148 and $89, respectively)	422	0.43	137	0.15
Cost Management Program[(h)] (net of taxes of $10 and $15, respectively)	29	0.03	24	0.03
Bargain Purchase Gain[(i)] (net of taxes of $0 and $0, respectively)	—	—	(233)	(0.25)
Asset Retirement Obligation[(n)] (net of taxes of $6 and $1, respectively)	16	0.02	(2)	—
Change in Environmental Liabilities (net of taxes of $1 and $0, respectively)	(4)	—	—	—
Like-Kind Exchange Tax Position[(j)] (net of taxes of $0 and $66, respectively)	—	—	(26)	(0.03)
Reassessment of Deferred Income Taxes[(k)] (entire amount represents tax expense)	(27)	(0.03)	(42)	(0.04)
Tax Settlements[(l)] (net of taxes of $0 and $1, respectively)	—	—	(5)	(0.01)
Noncontrolling Interests[(m)] (net of taxes of $9 and $16, respectively)	(36)	(0.04)	75	0.08
Adjusted (non-GAAP) Operating Earnings	$2,467	$ 2.55	$1,943	$ 2.06

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Note:

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 2018 and 2017 ranged from 26.0 percent to 29.0 percent and 39.0 percent to 41.0 percent, respectively. Under IRS regulations, NDT fund investment returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 7.7 percent and 43.2 percent for the three months ended September 30, 2018 and 2017, respectively. The effective tax rates for the unrealized gains and losses related to NDT fund investments were 55.5 percent and 46.2 percent for the nine months ended September 30, 2018 and 2017, respectively.

(a) Primarily reflects the impact of net gains and losses on Generation's economic hedging activities.

(b) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.

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(c) Reflects the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to the ConEdison Solutions and FitzPatrick acquisitions.

(d) Primarily reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2017, reflects costs related to the PHI and FitzPatrick acquisitions, offset at PHI by the anticipated recovery of previously incurred PHI acquisition costs. In 2018, reflects costs related to the PHI acquisition.

(e) Primarily reflects a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.

(f) Primarily reflects charges to earnings related to the impairment of the EGTP assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.

(g) Primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's previous decision to early retire the Three Mile Island nuclear facility in 2017. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, a charge associated with a remeasurement of the Oyster Creek ARO and accelerated depreciation and amortization expenses associated with the 2017 decision to early retire the Three Mile Island nuclear facility, partially offset by a gain associated with Generation's sale of its electrical contracting business.

(h) Primarily represents severance and reorganization costs related to a cost management program.

(i) Represents the excess fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

(j) Reflects adjustments to income tax, penalties and interest expenses in the second quarter of 2017 as a result of the finalization of the IRS tax computation related to Exelon’s like-kind exchange tax position.

(k) Reflects the changes in the Illinois and District of Columbia statutory tax rate and changes in forecasted apportionment in 2017. In 2018, reflects an adjustment to the remeasurement of deferred income taxes as a result of the Tax Cuts and Jobs Act (TCJA) and changes in forecasted apportionment.

(l) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI’s unregulated business interests.

(m) Reflects elimination from Generation’s results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments at CENG.

(n) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2017. In 2018, reflects an increase at Pepco related primarily to asbestos identified at its Buzzard Point property.

Significant 2018 Transactions and Developments

Regulatory Implications of the Tax Cuts and Jobs Act (TCJA)

The Utility Registrants have made filings with their respective State regulators to begin passing back to customers the ongoing annual tax savings resulting from the TCJA. The amounts being proposed to be passed back to customers reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. The Utility Registrants have identified over $675 million in ongoing annual savings to be returned to customers related to TCJA from their distribution utility operations. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Early Plant Retirements

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle in 2018. On September 17, 2018, Oyster Creek permanently ceased generation operations. Because of the decision to early retire Oyster Creek in 2018, Exelon and Generation recognized certain one-time charges in the first quarter of 2018 related to a materials and supplies inventory reserve adjustment, employee-related costs and construction work-in-progress impairments, among other items.

On July 31, 2018, Generation entered into an agreement with Holtec International and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC, for the sale and decommissioning of Oyster Creek. See

Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The plant is currently committed to operate through May 2019.

As a result of the early nuclear plant retirement decisions at Oyster Creek and TMI, Exelon and Generation will also recognize annual incremental non-cash charges to earnings stemming from

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shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. The following table summarizes the actual incremental non-cash expense item incurred in 2018 and the estimated amount of incremental non-cash expense items expected to be incurred in 2018 and 2019 due to the early retirement decisions.

Income statement expense (pre-tax)	Actual Nine Months Ended September 30, 2018	Projected[a] 2018	2019
Depreciation and amortization[b]			
Accelerated depreciation[c]	$ 441	$550	$330
Accelerated nuclear fuel amortization	52	55	5
Operating and maintenance[d]	32	35	5
Total	$ 525	$640	$340

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

(b) Reflects incremental accelerated depreciation and amortization for TMI and Oyster Creek for the nine months ended September 30, 2018. The Oyster Creek year-to-date amounts are from February 2, 2018 through September 17, 2018.

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

(d) Primarily includes materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments.

In 2017, PSEG also made public financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. Although Salem is committed to operate through May 2021, the plant faces continued economic challenges and PSEG, as the operator of the plant, is exploring all options.

On May 23, 2018, the Governor of New Jersey signed new legislation, which became effective immediately, that will establish a ZEC program providing 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 new 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. The NJBPU has 180 days from the effective date to establish procedures for implementation of the ZEC program and 330 days from the effective date to determine which nuclear power plants are selected to receive ZECs under the program. Assuming the successful implementation of the New Jersey ZEC program and the selection of Salem as one of the qualifying facilities, the New Jersey ZEC program has the potential to mitigate the heightened risk of earlier retirement for Salem. See Note 6 — Regulatory Matters and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on the new legislation and the New Jersey ZEC program.

On March 29, 2018, based on ISO-NE capacity auction results for the 2021 - 2022 planning year in which Mystic Unit 9 did not clear, Generation announced it had formally notified grid operator ISO-NE of its plans to early retire its Mystic Generating Station assets on June 1, 2022 absent any interim and long-term solutions for reliability and regional fuel security. The ISO-NE announced that it would take a three-step approach to fuel security. First, on May 1, 2018, ISO-NE made a filing with FERC requesting waiver of certain tariff provisions to allow it to retain Mystic Units 8 and 9 for fuel security for the 2022 - 2024 planning years. Second, ISO-NE planned to file tariff revisions to allow it to retain other resources for fuel security in the capacity market if necessary in the future. Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE's January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic Units 8 and 9, cannot

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recover future operating costs including the cost of procuring fuel. As a result of these developments, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group during the first quarter of 2018 and no impairment charge was required.

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 and 9 for the period between June 1, 2022 - May 31, 2024.

On July 2, 2018, FERC issued an order denying ISO-NE's May 1, 2018, waiver request on procedural grounds but accepting ISO-NE's conclusions that retirement of Mystic Units 8 and 9 could cause a violation of mandatory reliability standards as soon as 2022. Accordingly, FERC ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address demonstrated fuel security concerns and (ii) make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. FERC also extended the deadline by which Generation must make a retirement decision for Mystic Units 8 and 9 to January 4, 2019. On August 31, 2018, ISO-NE filed a compliance filing in response to FERC's July 2, 2018 order proposing short-term tariff changes to permit it to retain a resource for fuel security reliability reasons. A number of parties, including Generation, have submitted comments on the proposal, which is pending before FERC.

On July 13, 2018, FERC issued an order accepting the cost-of-service agreement for filing, making findings on certain issues and establishing hearing procedures on an expedited schedule. Further developments such as the failure of ISO-NE to adopt interim and long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group, which could be material. See Note 7 — Impairment of Long-Lived Assets and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

Illinois ZEC Procurement

Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation’s Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue. Winning bidders are entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the three months ended September 30, 2018, Generation recognized revenue of $61 million. During the nine months ended September 30, 2018, Generation recognized revenue of $315 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

Westinghouse Electric Company LLC Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. On January 4, 2018, Westinghouse announced its agreement to be purchased by an affiliate of Brookfield Business Partners, LLC (Brookfield) for approximately $4.6 billion. On March 28, 2018, the Bankruptcy Court entered an Order confirming the Debtor's Second Amended Joint Plan of Reorganization which provides for the transaction with Brookfield. The transaction closed on August 1, 2018. Exelon had contracts with Westinghouse primarily related to Generation's purchase of nuclear fuel, as well as a variety of services and equipment purchases associated with the operation and maintenance of nuclear generating stations. In conjunction with the confirmation hearing, Exelon had filed a reservation of rights regarding reorganizing Westinghouse's assumption of all Exelon contracts. Exelon reached an agreement with Brookfield, and all Exelon contracts were assumed by Brookfield on the closing date.

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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 results of operations, cash flows and financial position.

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2018. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Registrant	Jurisdiction	Approved Revenue Requirement Increase (Decrease) (in millions)	Approved Return on Equity	Completion Date	Rate Effective Date
Pepco	District of Columbia (Electric)	$ (24)	9.525 %	August 9, 2018	August 13, 2018
Pepco	Maryland (Electric)	$ (15)	9.5 %	May 31, 2018	June 1, 2018
DPL	Delaware (Electric)	$ (7)	9.7 %	August 21, 2018	March 17, 2018
DPL	Maryland (Electric)	$ 13	9.5 %	February 9, 2018	September 5, 2018

Pending Distribution Base Rate Case Proceedings

Registrant	Jurisdiction	Requested or Settlement Revenue Requirement Increase (Decrease) (in millions)	Requested or Settlement Return on Equity	Filing or Settlement Date	Expected Completion Timing
ComEd	Illinois (Electric)	$ (23)	8.69 %	April 16, 2018	Fourth quarter 2018
PECO	Pennsylvania (Electric)	$ 25	N/A[(a)]	August 28, 2018	Fourth quarter 2018
BGE	Maryland (Natural Gas)	$ 61	10.50 %	June 8, 2018 (Updated on August 24, 2018 and October 12, 2018)	First quarter 2019
DPL	Delaware (Natural Gas)	$ (4)	9.70 %	September 7, 2018 (Updated on October 2, 2018)	Fourth quarter 2018
ACE	New Jersey (Electric)	$ 109	10.10 %	August 21, 2018	Third quarter 2019

(a) No overall ROE was specified in the partial settlement agreement.

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on these base rate case proceedings.

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Transmission Formula Rate

The following total (decreases)/increases were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2018 annual electric transmission formula rate updates.

2018 Annual Transmission Updates[(a)(b)]	ComEd	BGE	Pepco	DPL	ACE
Initial revenue requirement (decrease) increase	$(44)	$10	$6	$14	$4
Annual reconciliation increase (decrease)	18	4	2	13	(4)
Dedicated facilities increase[(c)]	—	12	—	—	—
Total revenue requirement (decrease) increase	$(26)	$26	$8	$27	$—
Allowed return on rate base[(d)]	8.32 %	7.61%	7.82%	7.29%	8.02%
Allowed ROE[(e)]	11.50%	10.50%	10.50%	10.50%	10.50%

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(a) All rates are effective June 2018, subject to review by the FERC and other parties, which is due by fourth quarter 2018.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion above.

(c) BGE's transmission revenues include a FERC-approved dedicated facilities charge to recover the costs of providing transmission service to a specifically designated load by BGE.

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

(e) As part of the FERC-approved settlement of ComEd’s 2007 transmission rate case, the rate of return on common equity is 11.50% 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%. 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 regional transmission organization.

PECO Transmission Formula Rate

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the final outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

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Winter Storm-Related Costs

During March 2018 there were powerful nor'easter storms that brought a mix of heavy snow, ice and high sustained winds and gusts to the region that interrupted electric service delivery to customers in PECO's, BGE's, Pepco's, DPL's and ACE's service territories. Restoration efforts included significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies, which resulted in incremental operating and maintenance expense and incremental capital expenditures in the first quarter of 2018 for PECO, BGE, PHI, Pepco, DPL and ACE. In addition, PHI, Pepco, DPL and ACE recorded regulatory assets for amounts that are probable of recovery through customer rates. The impacts recorded by the Registrants for the nine months ended September 30, 2018 are presented below:

	Customer Outages	Incremental Operating & Maintenance (in millions)		Incremental Capital Expenditures
Exelon	1,727,000	$ 88	(b)	$ 89
PECO	750,000	53		35
BGE	425,000	31		15
PHI[a]	552,000	4	(b)	39
Pepco	182,000	2	(b)	4
DPL	138,000	2	(b)	4
ACE	232,000	—	(b)	31

(a) PHI reflects the consolidated customer outages, incremental operating & maintenance and incremental capital expenditures of Pepco, DPL and ACE.

(b) Excludes amounts that were deferred and recognized as regulatory assets at Exelon, PHI, Pepco, DPL and ACE of $28 million, $28 million, $7 million, $1 million and $20 million, respectively.

Exelon’s Strategy and Outlook for 2018 and Beyond

Exelon’s value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon’s regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- The Utility Registrants provide a foundation for steadily growing earnings, which translates to a stable currency in our stock.
- Generation’s competitive businesses provide free cash flow to invest primarily in the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon’s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Utility Registrants only invest in rate base where it provides a benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Utility Registrants make these investments at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, the Utility Registrants anticipate making significant future investments in smart meter

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technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation’s competitive businesses create value for customers by providing innovative energy solutions and reliable, clean and affordable energy. Generation’s electricity generation strategy is to pursue opportunities that provide stable revenues and generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation’s customer-facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon’s financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon’s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon's Board of Directors has approved a dividend policy providing a raise of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS of the Exelon 2017 Form 10-K for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon’s financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation, which was fully realized in 2018. Approximately 75% of the savings were related to Generation, with the remaining amount related to the Utility Registrants. In November 2017, Exelon announced a commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. In November 2018, Exelon announced the elimination of an approximately additional $200 million of annual ongoing costs, through initiatives primarily at Generation and BSC, by 2021. Approximately $150 million is expected to be related to Generation, with the remaining amount related to the Utility Registrants. These actions are in response to the continuing economic challenges confronting all parts of Exelon’s business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

Growth Opportunities

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

Regulated Energy Businesses. The PHI merger provides an opportunity to accelerate Exelon’s regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $28 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $11 billion by the end of 2022. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

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See Note 3 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements Exelon 2017 Form 10-K for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

Liquidity Considerations

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.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon Corporate, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1 billion, $0.6 billion, $0.6 billion, $0.3 billion, $0.3 billion and $0.3 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion.

For additional information regarding the Registrants' liquidity for the nine months ended September 30, 2018, see Liquidity and Capital Resources discussion below.

Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. 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. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt.

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Other Key Business Drivers and Management Strategies

Power Markets

Price of Fuels

The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

FERC Inquiry on Resiliency

On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by baseload generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. On January 8, 2018, FERC issued an order terminating the rulemaking docket that it initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Thereafter, interested parties submitted reply comments on May 9, 2018, and a few parties submitted further replies. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Complaints and PJM Filing at FERC Seeking to Mitigate ZEC Programs

PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to effectively remove the revenues it receives through a government-provided financial support program - resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new gas-fired resources.

On January 9, 2017, EPSA filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. A similar complaint also against PJM was filed at FERC on May 31, 2018. These complaints generally allege that the relevant MOPR should be expanded to also apply to existing resources including those receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS programs that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in PJM and NYISO that are currently receiving ZEC compensation (Quad Cities, Ginna, Fitzpatrick and Nine Mile Point), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any mitigation of these generating resources could have a material effect on Exelon's and Generation’s future cash flows and results of operations. The same risk would also exist for the Salem facility if Salem is selected as an eligible facility under the NJ ZEC program.

Separately, PJM submitted two proposed alternative capacity market reforms in April 2018 for FERC’s consideration. PJM argued that either alternative will resolve any conflict between state policy support for certain resources and the need to ensure reasonable prices for non-supported resources. The first alternative was to implement a twice-run capacity clearing mechanism (known as the repricing proposal) and, if not acceptable to FERC, a second alternative that would expand the existing MOPR to both new and existing generating resources, subject to certain exemptions (known as MOPREx).

In June 2018, FERC issued an order rejecting both of PJM’s proposed alternatives, finding both to be unjust and unreasonable. In the same order, FERC also addressed one of the MOPR complaints involving PJM and concluded based on that complaint and PJM’s filing that PJM’s existing tariff allows resources receiving out-of-market support to affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. FERC suggested that modifying two elements of PJM’s existing tariff could produce a just and reasonable replacement and asked for initial comments on its proposal by August 28, 2018, later extended to October 2, 2018. First, FERC found that an expansion of the current MOPR mechanism to cover all existing generating resources, regardless of resource type, including those receiving either ZEC or REC compensation, could protect the capacity markets from unwanted price suppression. Second, FERC preliminarily found that a modified version of PJM’s existing Fixed Resource Requirement (FRR) option could enable state subsidized resources and a corresponding amount of load to be removed from the capacity market, thereby alleviating their price suppressive effects on capacity clearing prices. Under this alternative, state supported generating resources would potentially be compensated through mechanisms other than through PJM’s existing market mechanism. FERC established March 21, 2016 as the refund effective date and also allowed PJM to delay its next capacity auction from May 2019 to August 2019 to allow parties time to develop and file proposals in the FERC proceeding, FERC time to determine the appropriate solution and PJM time to implement FERC's solution. On October 2, 2018, Exelon, along with several ratepayer advocates, environmental organizations and other nuclear generators, submitted shared principles supporting a workable new FRR mechanism (as suggested by FERC) and detailing how such a mechanism should be implemented. Exelon also submitted individual comments covering matters not addressed in the shared principles. FERC has not yet issued a decision on the second MOPR complaint involving PJM or the MOPR complaint involving NYISO. It is too early to predict the final outcome of each of these proceedings or their potential financial impact, if any, on Exelon or Generation.

Section 232 Uranium Petition

On January 16, 2018, two Canadian-owned uranium mining companies with operations in the U.S. jointly submitted a petition to the U.S. Department of Commerce (DOC) seeking relief under Section 232 of the Trade Expansion Act of 1962 (as amended) from imports of uranium products, alleging that these imports threaten national security (the Petition). The Trade Expansion Act of 1962 (the Act) was promulgated by Congress to protect essential national security industries whose survival is threatened by imports. As such, the Act authorizes the Secretary of Commerce (the Secretary) to conduct investigations to evaluate the effects of imports of any item on the national security of the U.S. The Petition alleges that the loss of a viable U.S. uranium mining industry would have a significant detrimental impact on the national, energy, and economic security of the U.S. and the ability of the country to sustain an independent nuclear fuel cycle.

On July 18, 2018, the Secretary announced that the DOC has initiated an investigation in response to the petition. The Secretary has 270 days to prepare and submit a report to President Trump, who then has 90 days to act on the Secretary's recommendations. Exelon and Generation cannot currently predict the outcome of this investigation. The relief sought by the petitioners would require U.S. nuclear reactors

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to purchase at least 25% of their uranium needs from domestic mines over the next 10 years, although the DOC will make an independent determination regarding an appropriate remedy should it find that imports impair national security. It is reasonably possible that if this petition is successful the resulting increase in nuclear fuel costs in future periods could have a material, unfavorable impact on Exelon’s and Generation’s results of operations, cash flows and financial positions.

Potential DOE Order Pursuant to Defense Production Act and Federal Power Act

The DOE is considering an Order directing ISOs, for 24 months, to purchase electric energy or generation capacity from a designated list of coal and nuclear generation facilities. Based on a draft memorandum, the Order would be pursuant to DOE's authorities under the Defense Production Act and Federal Power Act, and would forestall any further actions towards retiring, decommissioning, or deactivating coal and nuclear facilities during the term of the Order. The Order would emphasize the importance of grid resiliency, in addition to grid reliability, noting that fuel security and diversity are critical components of resiliency. The DOE recognizes that the underlying economic and regulatory issues are complex and will take time resolve. The Order's 24-month duration would enable DOE to conduct additional analyses to gain a detailed understanding of location-specific vulnerabilities in U.S. energy delivery systems, while preserving certain generation facilities. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in relatively flat load growth in electricity for the Utility Registrants. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase by 0.5%, 1.7%, 0.7%, 0.2%, 1.3% and 4.3% respectively, in 2018 compared to 2017.

Retail Competition

Generation’s retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. Forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices and the impacts of hypothetical credit downgrades.

Exelon's board of directors declared first quarter 2018 dividends of $0.345 per share on Exelon's common stock. The first quarter 2018 dividend was paid on March 9, 2018. The dividend increased from the fourth quarter 2017 amount to reflect the Board's decision to raise Exelon's dividend 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Exelon's board of directors declared second quarter 2018 dividends of $0.345 per share on Exelon's common stock and was paid on June 8, 2018.

Exelon's board of directors declared third quarter 2018 dividends of $0.345 per share on Exelon's common stock and was paid on September 10, 2018.

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Exelon's board of directors declared fourth quarter 2018 dividends of $0.345 per share on Exelon's common stock and is payable on December 10, 2018.

All future quarterly dividends require approval by Exelon's Board of Directors.

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. Generation has hedges in place that significantly mitigate this risk for 2018 and 2019. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of September 30, 2018, the percentage of expected generation hedged is 98%-101%, 82%-85% and 48%-51% for 2018, 2019, and 2020 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is 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, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 59% of Generation's uranium concentrate requirements from 2018 through 2022 are supplied by three producers. 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 results of operations, cash flows and financial positions.

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

Environmental Legislative and Regulatory Developments

Exelon was actively involved in the Obama Administration's development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.

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Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration's actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon's and its subsidiaries results of operations and cash flows.

In particular, the Administration has targeted certain existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings and withdrew all technical support documents supporting the calculation. Other regulations that are under review include the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, and the Coal Combustion Residuals rule. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

Mercury and Air Toxics Standard Rule (MATS). On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two-year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court's opinion on this single issue. On April 27, 2017, the D.C. Circuit granted EPA's motion to hold the litigation in abeyance, pending EPA's review of the MATS rule pursuant to President Trump's EO discussed above. Following EPA's review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court's order to hold the litigation in abeyance, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

Clean Power Plan. On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA's actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency's legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction ("BSER") for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. The EPA has also issued an advance notice of proposed rulemaking to solicit information on systems of emission reduction that are in accord with the Agency's proposed revised legal interpretation; namely, only by regulating emission reductions that can be implemented at and to individual sources.

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2015 Ozone National Ambient Air Quality Standards (NAAQS). On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA's further review of the 2015 Rule. Concurrent with its review, the Agency issued several rounds of final ozone designations for the 2015 ozone NAAQS in December 2017 and April 2018. On August 1, 2018, EPA filed a status report to the Court that indicated Agency does not intend to revise or repeal the 2015 ozone standard at this time. Subsequently the Court ordered the case reactivated.

Primary SO2 National Ambient Air Quality Standards (NAAQS). On June 8, 2018, the EPA proposed to maintain the primary NAAQS for sulfur dioxide (SO2) at the same level and averaging time as was finalized by EPA in its 2010 SO2 NAAQS update. The schedule for completing this review is established by a consent decree, which sets January 28, 2019 as the deadline for signature on a final decision notice.

Climate Change. Exelon supports comprehensive climate change legislation or regulation which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In June 2018, Exelon joined the Climate Leadership Council, which advocates for a revenue neutral carbon tax and dividend program. In the absence of Federal legislation, the EPA has been reviewing the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" or "Convention"). See ITEM 1. BUSINESS, "Air Quality" of the Exelon 2017 Form 10-K for additional information.

Water Quality

Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Handley, Mystic Unit 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS, "Water Quality" of the Exelon 2017 Form 10-K for additional information.

Solid and Hazardous Waste

In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classified CCR as non-hazardous waste under RCRA, and CCR continued to be regulated by most states subject to coordination with the federal regulations. In July 2018, the EPA issued a final rule amending the 2015 rule that provides more compliance flexibility to the states and owners and operators of coal ash disposal sites. Generation currently does not own or operate any such sites subject to the CCR rule. Generation previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the CCR rule is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the CCR rule for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to environmental matters, including the impact of environmental regulation.

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Other Legislative and Regulatory Developments

Delaware Distribution System Investment Charge

On June 14, 2018, the Governor of Delaware signed new Distribution System Investment Charge (DSIC) legislation, which establishes a system improvement charge that provides a mechanism to recover infrastructure investments, allowing for gradual rate increases and limiting frequency of distribution base rate cases. DPL expects to make its first filing in Delaware in the fourth quarter of 2018, with the new charge effective in the first quarter of 2019. While this legislation is expected to support needed infrastructure investment and allow for more timely recovery of those investments, Exelon, PHI and DPL cannot predict the potential financial impact on Exelon, PHI or DPL.

Pennsylvania Alternative Ratemaking

On June 28, 2018, the Governor of Pennsylvania signed new legislation, which authorized the PAPUC to review and approve utility-proposed alternative rate mechanisms, including options such as decoupling mechanisms, formula rates, multi-year rate plans, and performance based rates. Exelon and PECO cannot predict the outcome or the potential financial impact, if any, on Exelon or PECO.

Employees

In January 2017, an election was held at BGE which resulted in union representation for approximately 1,394 employees. BGE and IBEW Local 410 are negotiating an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. Negotiations have been productive and continue. No agreement has been finalized to date and management cannot predict the outcome of such negotiations. Negotiations that began in 2017 for a first collective bargaining agreement with a small unit of employees represented by Local 501 of Operating Engineers at Exelon’s Hyperion Solutions facility are complete and the new CBA will expire in 2021. During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at Fitzpatrick into one CBA covering both craft and security employees, which will expire in 2023. Generation also successfully finalized the CBA with the IBEW union at TMI, which will expire in 2022. During 2018, Generation finalized its CBA with the Security Officer’s union at Braidwood, which will expire in 2021. Additionally, negotiations are currently underway for the two ACE Local 210 contracts, which expire on October 15, 2018 and December 9, 2018. Both sides are bargaining in good faith and we anticipate a mutually acceptable outcome from these negotiations. As previously reported, there was an organizing effort over approximately 18 ACE control room System Operators. While an election was held with an outcome favorable to Local 210, collective bargaining over this small segment of employees will not commence until the issue of whether the System Operators are NLRA statutory supervisors is determined, and that matter is currently before the NLRB.

Critical Accounting Policies and Estimates

Revenue Recognition (All Registrants)

Sources of Revenue and Determination of Accounting Treatment

The Registrants earn revenues from various business activities including: the sale of power and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail); the sale and delivery of power and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily apply the Revenue from

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Contracts with Customers, Derivative and Alternative Revenue Program (ARP) guidance to recognize revenue as discussed in more detail below.

Revenue from Contracts with Customers

Under the Revenue from Contracts with Customers guidance, the Registrants recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power, natural gas, and other energy-related commodities are physically delivered to the customer. Transactions of the Registrants within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as normal purchases and normal sales (NPNS), sales to utility customers under regulated service tariffs, and spot-market energy commodity sales, including settlements with independent system operators.

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

See Note 5 — Accounts Receivable of the Exelon 2017 Form 10-K for additional information on unbilled revenue.

See Note 1 — Significant Accounting Policies and Note 5 — Revenue from Contracts with Customers of the Combined Notes to Consolidated Financial Statements for additional information on the impacts of the new revenue accounting standard effective for annual reporting periods beginning on or after December 15, 2017.

Derivative Revenues

The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that are accounted for as derivatives. These derivative transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable, unrealized gains and losses from changes in the fair value of open contracts, and realized gains and losses.

Alternative Revenue Program Revenues

Certain of the Utility Registrants’ ratemaking mechanisms qualify as Alternative Revenue Programs (ARPs) if they (i) are established by a regulatory order and allow for automatic adjustment to future rates, (ii) provide for additional revenues (above those amounts currently reflected in the price of utility service) that are objectively determinable and probable of recovery, and (iii) allow for the collection of those additional revenues within 24 months following the end of the period in which they were recognized. For mechanisms that meet these criteria, which include the Utility Registrants’ formula rate and revenue decoupling mechanisms, the Utility Registrants adjust revenue and record an offsetting regulatory asset or liability once the condition or event allowing additional billing or refund has occurred. The ARP revenues presented in the Utility Registrants’ Consolidated Statements of Operations and Comprehensive Income

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include both: (i) the recognition of “originating” ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the “originating” ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

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

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — CRITICAL ACCOUNTING POLICIES AND ESTIMATES in Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's combined 2017 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants’ accounting for AROs, goodwill, purchase accounting, unamortized energy contract assets and liabilities, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies, revenue recognition and allowance for uncollectible accounts. At September 30, 2018, the Registrants’ critical accounting policies and estimates had not changed significantly from December 31, 2017.

Results of Operations by Registrant

Net Income Attributable to Common Shareholders by Registrant

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Exelon	$733	$823	$ (90)	$1,858	$1,907	$ (49)
Generation	234	304	(70)	547	487	60
ComEd	193	189	4	523	447	76
PECO	126	112	14	336	327	9
BGE	63	62	1	242	231	11
PHI	187	153	34	336	359	(23)
Pepco	89	87	2	174	188	(14)
DPL	33	31	2	90	107	(17)
ACE	61	41	20	76	77	(1)

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Results of Operations — Generation

	Three Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$5,278	$4,750	$ 528	$15,368	$13,843	$ 1,525
Purchased power and fuel expense	2,980	2,331	(649)	8,552	7,286	(1,266)
Revenues net of purchased power and fuel expense[(a)]	2,298	2,419	(121)	6,816	6,557	259
Other operating expenses						
Operating and maintenance	1,370	1,376	6	4,126	4,879	753
Depreciation and amortization	468	410	(58)	1,383	1,046	(337)
Taxes other than income	143	141	(2)	414	425	11
Total other operating expenses	1,981	1,927	(54)	5,923	6,350	427
(Loss) gain on sales of assets and businesses	(6)	(2)	(4)	48	3	45
Bargain purchase gain	—	7	(7)	—	233	(233)
Operating income	311	497	(186)	941	443	498
Other income and (deductions)						
Interest expense, net	(101)	(113)	12	(305)	(342)	37
Other, net	179	209	(30)	164	648	(484)
Total other income and (deductions)	78	96	(18)	(141)	306	(447)
Income before income taxes	389	593	(204)	800	749	51
Income taxes	78	239	161	110	215	105
Equity in losses of unconsolidated affiliates	(11)	(8)	(3)	(23)	(26)	3
Net income	300	346	(46)	667	508	159
Net income attributable to noncontrolling interests	66	42	(24)	120	21	(99)
Net income attributable to membership interest	$234	$304	$ (70)	$547	$487	$ 60

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense 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.

Net Income Attributable to Membership Interest

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Generation's Net income attributable to membership interest for the three months ended September 30, 2018 decreased compared to the same period in 2017, primarily due to lower Revenue net of purchased power and fuel expense, higher Depreciation and amortization expenses, lower Other income, partially offset by lower Operating and maintenance expenses and lower Income taxes. The decrease in Revenue net of purchased power and fuel expense primarily relates to the absence of EGTP

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revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower realized energy prices, lower energy efficiency revenues, decreased revenues related to the sale of Generation's electrical contracting business in 2018 and increased nuclear outage days, partially offset by the impact of the Illinois ZES and increased capacity prices. The decrease in Operating and maintenance expenses is primarily due to charges to earnings related to the impairment of the EGTP assets held for sale in 2017, decreased costs related to the sale of Generation's electrical contracting business in 2018 and decreased spending related to energy efficiency projects, partially offset by a charge associated with a remeasurement of the Oyster Creek ARO. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's decision to early retire the Oyster Creek and TMI nuclear facilities. The decrease in Other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. The decrease in Income taxes is primarily due to tax savings related to the TCJA.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Generation’s Net income attributable to membership interest for the nine months ended September 30, 2018 increased compared to the same period in 2017, primarily due to higher Revenue net of purchased power and fuel expense, lower Operating and maintenance expenses and lower Income taxes, partially offset by higher Depreciation and amortization expenses, a Bargain purchase gain in 2017 and lower Other income. The increase in Revenue net of purchased power and fuel expense primarily relates to the impacts of the New York CES and Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, the acquisition of the FitzPatrick nuclear facility, decreased nuclear outage days, the addition of two combined-cycle gas turbines in Texas and the impacts of Generation's natural gas portfolio, partially offset by lower realized energy prices, the absence of EGTP revenues net of purchased power and fuel expense resulting from its deconsolidation in the fourth quarter of 2017, lower energy efficiency revenues and decreased revenues related to the sale of Generation's electrical contracting business in 2018. The decrease in Operating and maintenance is primarily due to the impairment of EGTP assets held for sale in 2017, decreased nuclear outage days in 2018, the impact of a supplemental NEIL distribution, certain costs associated with mergers and acquisitions related to the PHI and FitzPatrick acquisitions, decreased costs related to the sale of Generation's electrical contracting business in 2018 and decreased spending related to energy efficiency projects, partially offset by one-time charges associated with Generation's decision to early retire the TMI and Oyster Creek nuclear facilities. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's decision to early retire the Oyster Creek and TMI nuclear facilities. The Bargain purchase gain in 2017 is due to the acquisition of the FitzPatrick nuclear facility. The decrease in Other income is primarily due to the change in unrealized gains and losses on NDT funds.

Revenues Net of Purchased Power and Fuel Expense

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. Descriptions of each of Generation’s six 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, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO’s Southern Region, which covers all or most of North Dakota,

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South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Power Regions:
- South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
- West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
- Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

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 Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.

Generation evaluates the operating performance of its electric business activities using the measure of Revenue net of purchased power and fuel expense, which is a non-GAAP measurement. 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 owned generation and fuel costs associated with tolling agreements.

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For the three and nine months ended September 30, 2018 and 2017, Generation's Revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Variance	% Change	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Variance	% Change
Mid-Atlantic[(a)]	$763	$855	$(92)	(10.8)%	$2,348	$2,411	$(63)	(2.6)%
Midwest[(b)]	768	697	71	10.2%	2,400	2,140	260	12.1%
New England	81	145	(64)	(44.1)%	298	403	(105)	(26.1)%
New York[(d)]	292	295	(3)	(1.0)%	841	707	134	19.0%
ERCOT	98	118	(20)	(16.9)%	216	258	(42)	(16.3)%
Other Power Regions	99	68	31	45.6%	309	220	89	40.5%
Total electric revenue net of purchased power and fuel expense	2,101	2,178	(77)	(3.5)%	6,412	6,139	273	4.4%
Proprietary Trading	5	4	1	25.0%	39	11	28	254.5%
Mark-to-market gains (losses)	71	73	(2)	(2.7)%	(104)	(161)	57	(35.4)%
Other[(c)]	121	164	(43)	(26.2)%	469	568	(99)	(17.4)%
Total revenue net of purchased power and fuel expense	$2,298	$2,419	$(121)	(5.0)%	$6,816	$6,557	$259	3.9%

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL and ACE are included in the Mid-Atlantic region.

(b) Results of transactions with ComEd are included in the Midwest region.

(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $19 million decrease to revenue net of purchased power and fuel expense for the three months ended September 30, 2017, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements of a $18 million decrease and $6 million decrease to revenue net of purchased power and fuel expense for the three months ended September 30, 2018 and 2017, respectively. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of a $41 million decrease to revenue net of purchased power and fuel expense for the nine months ended September 30, 2017, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements of a $53 million decrease and $8 million decrease to revenue net of purchased power and fuel expense for the nine months ended September 30, 2018 and 2017, respectively.

(d) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Generation's supply sources by region are summarized below:

Supply source (GWhs)	Three Months Ended September 30, 2018	2017	Variance	% Change	Nine Months Ended September 30, 2018	2017	Variance	% Change
Nuclear Generation								
Mid-Atlantic[a]	16,197	16,480	(283)	(1.7)%	48,924	48,271	653	1.4%
Midwest	23,834	24,362	(528)	(2.2)%	70,532	69,422	1,110	1.6%
New York[a][c]	6,518	6,905	(387)	(5.6)%	19,758	17,623	2,135	12.1%
Total Nuclear Generation	46,549	47,747	(1,198)	(2.5)%	139,214	135,316	3,898	2.9%
Fossil and Renewables								
Mid-Atlantic	853	596	257	43.1%	2,660	2,330	330	14.2%
Midwest	244	218	26	11.9%	1,020	1,053	(33)	(3.1)%
New England	1,339	1,919	(580)	(30.2)%	4,189	5,921	(1,732)	(29.3)%
New York	1	1	—	—%	3	3	—	—%
ERCOT	3,137	5,703	(2,566)	(45.0)%	8,389	9,388	(999)	(10.6)%
Other Power Regions	2,289	2,149	140	6.5%	6,503	5,656	847	15.0%
Total Fossil and Renewables	7,863	10,586	(2,723)	(25.7)%	22,764	24,351	(1,587)	(6.5)%
Purchased Power								
Mid-Atlantic	3,504	2,541	963	37.9%	4,828	8,840	(4,012)	(45.4)%
Midwest	174	217	(43)	(19.8)%	733	1,018	(285)	(28.0)%
New England	7,217	4,513	2,704	59.9%	18,607	13,920	4,687	33.7%
New York	—	—	—	—%	—	28	(28)	(100.0)%
ERCOT	1,811	1,199	612	51.0%	5,504	5,724	(220)	(3.8)%
Other Power Regions	5,488	3,982	1,506	37.8%	14,124	10,357	3,767	36.4%
Total Purchased Power	18,194	12,452	5,742	46.1%	43,796	39,887	3,909	9.8%
Total Supply/Sales by Region								
Mid-Atlantic[b]	20,554	19,617	937	4.8%	56,412	59,441	(3,029)	(5.1)%
Midwest[b]	24,252	24,797	(545)	(2.2)%	72,285	71,493	792	1.1%
New England	8,556	6,432	2,124	33.0%	22,796	19,841	2,955	14.9%
New York	6,519	6,906	(387)	(5.6)%	19,761	17,654	2,107	11.9%
ERCOT	4,948	6,902	(1,954)	(28.3)%	13,893	15,112	(1,219)	(8.1)%
Other Power Regions	7,777	6,131	1,646	26.8%	20,627	16,013	4,614	28.8%
Total Supply/Sales by Region	72,606	70,785	1,821	2.6%	205,774	199,554	6,220	3.1%

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(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).

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

(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Mid-Atlantic

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $92 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices, partially offset by increased capacity prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $63 million decrease in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices, partially offset by increased capacity prices and decreased nuclear outage days.

Midwest

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $71 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois ZES and increased capacity prices, partially offset by increased nuclear outage days.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $260 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois ZES (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017), increased capacity prices, and decreased nuclear outage days, partially offset by lower realized energy prices.

New England

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $64 million decrease in Revenue net of purchased power and fuel expense in New England primarily reflects lower realized energy prices and decreased capacity prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $105 million decrease in Revenue net of purchased power and fuel expense in New England primarily reflects lower realized energy prices, partially offset by increased capacity prices.

New York

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $3 million decrease in Revenue net of purchased power and fuel expense in New York was primarily due to increased nuclear outage days and the resulting decreased ZEC revenues related to New York CES, partially offset by higher realized energy prices and increased capacity prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $134 million increase in Revenue net of purchased power and fuel expense in New York was primarily due to the impact of the New York CES and the acquisition of FitzPatrick, partially offset by the conclusion of the Ginna Reliability Support Service Agreement in Q1 2017.

ERCOT

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $20 million decrease in Revenue net of purchased power and fuel expense in ERCOT was primarily due to the deconsolidation of EGTP in 2017, partially offset by higher realized energy prices and the addition of two combined-cycle gas turbines in Texas.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $42 million decrease in Revenue net of purchased power and fuel expense in ERCOT was

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primarily due to the deconsolidation of EGTP in 2017, partially offset by the addition of two combined-cycle gas turbines in Texas and higher realized energy prices.

Other Power Regions

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $31 million increase in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $89 million increase in Revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Proprietary Trading

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $1 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $28 million increase in Revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Mark-to-market

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Mark-to-market gains on economic hedging activities were $71 million for the three months ended September 30, 2018 compared to gains of $73 million for the three months ended September 30, 2017. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on gains and losses associated with mark-to-market derivatives.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Mark-to-market losses on economic hedging activities were $104 million for the nine months ended September 30, 2018 compared to losses of $161 million for the nine months ended September 30, 2017. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. The $43 million decrease in Revenue net of purchased power and fuel expense in Other was due to the decline in revenues related to the energy efficiency business, the sale of Generation's electrical contracting business in 2018, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, partially offset by the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. The $99 million decrease in Revenue net of purchased power and fuel expense in Other was due to the decline in revenues related to the energy efficiency business, the sale of Generation's electrical contracting business in 2018, and accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, partially offset by Generation's higher natural gas portfolio

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optimization and the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for the three and nine months ended September 30, 2018 compared to the same period in 2017 for the Generation-operated plants. 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,	
	2018	2017	2018	2017
Nuclear fleet capacity factor[a]	93.6%	96.1%	94.4%	93.7%
Refueling outage days[a]	36	13	198	233
Non-refueling outage days[a]	12	15	20	35

(a) Reflects ownership percentage of stations operated by Exelon. Excludes Salem, which is operated by PSEG Nuclear, LLC. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

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Operating and Maintenance Expense

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 as compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)[a]	Nine Months Ended September 30, 2018 Increase (Decrease)[a]
Labor, other benefits, contracting, materials[b]	$ (50)	$ (163)
Nuclear refueling outage costs, including the co-owned Salem plants[c]	40	(56)
Insurance[d]	(2)	(38)
Merger and integration costs[e]	(11)	(66)
Plant retirements and divestitures[f]	90	47
Change in environmental liabilities	(12)	(5)
Long-lived asset impairments[g]	(33)	(411)
Pension and non-pension postretirement benefits expense	(7)	(18)
Allowance for uncollectible accounts	(3)	(13)
Other	(18)	(30)
Decrease in Operating and maintenance expense	$ (6)	$ (753)

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(a) The financial results include Generation's acquisition of the FitzPatrick nuclear generating station from March 31, 2017.

(b) Primarily reflects decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business in 2018.

(c) Primarily reflects an increase in the number of nuclear outage days for the three months ended September 30, 2018 compared to the same period in 2017 and a decrease in the number of nuclear outage days for the nine months ended September 30, 2018 compared to the same period in 2017.

(d) Primarily reflects the impact of a supplemental NEIL insurance distribution.

(e) Primarily reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities related to the PHI and FitzPatrick acquisitions in 2017, and the PHI acquisition in 2018.

(f) Primarily reflects one-time charges associated with Generation’s decision to early retire the Oyster Creek nuclear facility including ARO in 2018 and the TMI nuclear facility in 2017.

(g) Primarily reflects charges to earnings related to the impairment of the EGTP assets held for sale in 2017, and in 2018 the impairment of certain wind projects at Generation.

Depreciation and Amortization Expense

Depreciation and amortization expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 increased primarily due to accelerated depreciation and amortization due to Generation's decision to early retire the Oyster Creek and TMI nuclear facilities.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

(Loss) gain on Sales of Assets and Businesses

Loss on sales of assets and businesses for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent. Gain on sales of assets and businesses for the nine months ended September 30, 2018 compared to the same period in 2017 increased primarily due to Generation's 2018 sale of its electrical contracting business.

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Bargain Purchase Gain

Bargain purchase gain for the three and nine months ended September 30, 2018 compared to the same period in 2017 decreased as a result of the gain associated with the FitzPatrick acquisition in 2017. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 primarily reflects decreased interest expense due to the retirement of long-term debt.

Other, Net

Other, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 decreased primarily due to the change in the realized and unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $29 million and $37 million for the three months ended September 30, 2018 and 2017, respectively, and $24 million and $129 million for the nine months ended September 30, 2018 and 2017, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units. See Note 13 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and nine months ended September 30, 2018 and 2017:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net unrealized gains (losses) on decommissioning trust funds	$72	$111	$(143)	$347
Net realized gains on sale of decommissioning trust funds	29	33	164	82

Equity in Losses of Unconsolidated Affiliates

Equity in losses of unconsolidated affiliates for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Effective Income Tax Rate

Generation's effective income tax rate was 20.1% and 40.3% for the three months ended September 30, 2018 and 2017, respectively. Generation's effective income tax rate was 13.8% and 28.7% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018 compared to the same periods in 2017 is primarily related to tax savings due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information of the change in the effective income tax rate.

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Results of Operations — ComEd

	Three Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$1,598	$1,571	$ 27	$4,508	$4,227	$ 281
Purchased power expense	619	529	(90)	1,702	1,241	(461)
Revenues net of purchased power expense[(a)(b)]	979	1,042	(63)	2,806	2,986	(180)
Other operating expenses						
Operating and maintenance	337	346	9	974	1,096	122
Depreciation and amortization	237	212	(25)	696	631	(65)
Taxes other than income	82	80	(2)	238	223	(15)
Total other operating expenses	656	638	(18)	1,908	1,950	42
Gain on sales of assets	—	—	—	5	—	5
Operating income	323	404	(81)	903	1,036	(133)
Other income and (deductions)						
Interest expense, net	(85)	(89)	4	(261)	(275)	14
Other, net	7	5	2	21	14	7
Total other income and (deductions)	(78)	(84)	6	(240)	(261)	21
Income before income taxes	245	320	(75)	663	775	(112)
Income taxes	52	131	79	140	328	188
Net income	$193	$189	$ 4	$523	$447	$ 76

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense 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.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. ComEd's Net income for the three months ended September 30, 2018 was higher than the same period in 2017 primarily due to higher electric distribution and energy efficiency formula rate earnings. The TCJA did not significantly impact ComEd's net income for the three months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. ComEd's Net income for the nine months ended September 30, 2018 was higher than the same period in 2017 primarily due to higher electric distribution and energy efficiency formula rate earnings as well as additional tax and interest recorded in the second quarter of 2017 relating to Exelon's like-kind exchange tax position. The TCJA did not significantly impact ComEd's net income for the nine

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months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity, REC, and ZEC procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity, REC, and ZEC procurement costs from retail customers without mark-up. Therefore, fluctuations in these costs have no impact on Revenue net of purchased power expense. See Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K for additional information on ComEd's electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries but do affect ComEd's Operating revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	67 %	68 %	68 %	70 %

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,367,700	34 %	1,360,800	34 %

The changes in ComEd's Revenue net of purchased power expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Electric distribution revenue	$ (59)	$ (126)
Transmission revenue	(16)	(32)
Energy efficiency revenue[(a)]	14	31
Regulatory required programs[(a)]	(1)	(95)
Uncollectible accounts recovery, net	2	5
Other	(3)	37
Total decrease	$ (63)	$ (180)

(a) Beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

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Revenue Decoupling. The demand for electricity is affected by weather conditions. Under FEJA, ComEd revised its electric distribution rate formula effective January 1, 2017 to eliminate the favorable and unfavorable impacts on Operating revenues associated with variations in delivery volumes associated with above or below normal weather, numbers of customers or usage per customer.
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 ComEd's service territory with cooling degree-days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree-days in ComEd’s service territory for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	56	42	97	33.3%	(42.3)%
Cooling Degree-Days	895	699	641	28.0%	39.6 %
Nine Months Ended September 30,					
Heating Degree-Days	3,993	3,269	3,972	22.1%	0.5 %
Cooling Degree-Days	1,259	962	882	30.9%	42.7 %

Electric 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, investments being recovered, and allowed ROE. ComEd’s allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. In addition, ComEd's allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. Electric distribution revenue decreased during the three and nine months ended September 30, 2018, primarily due to the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters and Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
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. For the three months ended September 30, 2018, ComEd recorded decreased transmission revenue primarily due to the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. For the nine months ended September 30, 2018, ComEd recorded decreased transmission revenue primarily due to the decreased peak load and the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased depreciation expense as compared to the same period in 2017. See Operating and maintenance expense below and Note 6 — Regulatory Matters and Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.
Energy Efficiency Revenue. Beginning June 1, 2017, FEJA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual

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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. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points. Beginning January 1, 2018, ComEd's allowed ROE is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. See Depreciation and amortization expense discussions below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved rate riders to recover costs incurred for regulatory programs such as ComEd's purchased power administrative costs and energy efficiency and demand response through June 1, 2017 pursuant to FEJA. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs. The increase in Other revenue for the nine months ended September 30, 2018 compared to the same period in 2017 primarily reflects mutual assistance revenues associated with hurricane and winter storm restoration efforts. An equal and offsetting amount has been included in Operating and maintenance expense and Taxes other than income.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$336	$344	$ (8)	$973	$1,000	$ (27)
Operating and maintenance expense — regulatory required programs[(a)]	1	2	$ (1)	1	96	(95)
Total Operating and maintenance expense	$337	$346	$ (9)	$974	$1,096	$ (122)

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The decrease in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials[a]	$ (1)	$ (3)
Pension and non-pension postretirement benefits expense[a]	(1)	(1)
Storm-related costs	(5)	(21)
Uncollectible accounts expense — provision[b]	7	11
Uncollectible accounts expense — recovery, net[b]	(5)	(6)
BSC costs[a]	(9)	(8)
Other[a]	6	1
	(8)	(27)
Regulatory required programs		
Energy efficiency and demand response programs[c]	(1)	(95)
Decrease in operating and maintenance expense	$ (9)	$ (122)

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three and nine months ended September 30, 2018, ComEd recorded a net increase in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(c) Beginning June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Depreciation and Amortization Expense

The increase in Depreciation and amortization expense during the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase	Nine Months Ended September 30, 2018 Increase
Depreciation expense[a]	$ 9	$ 30
Regulatory asset amortization[b]	16	35
Total increase	$ 25	$ 65

(a) Primarily reflects ongoing capital expenditures for the three and nine months ended September 30, 2018.

(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency formula rate regulatory asset.

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes and payroll taxes.

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Gain on Sales of Assets

The increase in Gain on sales of assets during the nine months ended September 30, 2018 compared to the same period in 2017, is primarily due to the sale of land in March 2018.

Interest Expense, Net

The changes in Interest expense, net, for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Interest expense related to uncertain tax positions[(a)]	$ —	$ (13)
Interest expense on debt (including financing trusts)	(2)	2
Other	(2)	(3)
Total decrease	$ (4)	$ (14)

(a) Primarily reflects additional interest recorded in the second quarter of 2017 related to Exelon's like-kind exchange tax position.

Other, Net

Other, net, remained relatively consistent for the three and nine months ended September 30, 2018 compared to the same period in 2017.

Effective Income Tax Rate

ComEd's effective income tax rate was 21.2% and 40.9% for the three months ended September 30, 2018 and 2017, respectively. ComEd's effective income tax rate was 21.1% and 42.3% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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ComEd Electric Operating Statistics Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2018	2017	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather-Normal % Change
Retail Deliveries[a]								
Residential	8,845	8,004	10.5 %	(1.5)%	22,019	20,164	9.2 %	0.1 %
Small commercial & industrial	8,626	8,488	1.6 %	(1.0)%	24,204	23,634	2.4 %	— %
Large commercial & industrial	7,450	7,232	3.0 %	1.1 %	21,398	20,712	3.3 %	1.6 %
Public authorities & electric railroads	301	302	(0.3)%	(0.5)%	947	928	2.0 %	1.2 %
Total retail deliveries	25,222	24,026	5.0 %	(0.5)%	68,568	65,438	4.8 %	0.6 %

Number of Electric Customers	As of September 30, 2018	2017
Residential	3,635,678	3,610,091
Small commercial & industrial	380,529	376,309
Large commercial & industrial	1,994	1,954
Public authorities & electric railroads	4,767	4,763
Total	4,022,968	3,993,117

(a) Reflects delivery volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

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Results of Operations — PECO

	Three Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$757	$715	$ 42	$2,275	$2,141	$ 134
Purchased power and fuel expense	263	235	(28)	818	719	(99)
Revenues net of purchased power and fuel expense[(a)]	494	480	14	1,457	1,422	35
Other operating expenses						
Operating and maintenance	219	197	(22)	686	595	(91)
Depreciation and amortization	75	72	(3)	224	213	(11)
Taxes other than income	46	42	(4)	125	116	(9)
Total other operating expenses	340	311	(29)	1,035	924	(111)
Gain on sales of assets	—	—	—	1	—	1
Operating income	154	169	(15)	423	498	(75)
Other income and (deductions)						
Interest expense, net	(32)	(31)	(1)	(96)	(93)	(3)
Other, net	2	2	—	4	6	(2)
Total other income and (deductions)	(30)	(29)	(1)	(92)	(87)	(5)
Income before income taxes	124	140	(16)	331	411	(80)
Income taxes	(2)	28	30	(5)	84	89
Net income	$126	$112	$ 14	$336	$327	$ 9

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not presentations defined under GAAP and may not be comparable to other companies’ presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. PECO's Net income increased from the same period in 2017, primarily due to higher Operating revenues net of purchase power and fuel expense attributable to favorable weather and volume. The TCJA did not significantly impact PECO's Net income for the three and nine months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. PECO's Net income increased from the same period in 2017, primarily due to higher Operating revenues net of purchase power and fuel expense attributable to favorable weather and volume, partially offset by higher Operating and maintenance expense attributable to increased storm restoration costs as a result of winter storms in March 2018. The TCJA did not significantly impact PECO's Net income for the three and nine months ended September 30, 2018 as the favorable income tax impacts were

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predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenue net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customer's Choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and natural gas revenues net of purchased power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	68 %	70 %	69 %	71 %
Natural Gas	31 %	29 %	26 %	26 %

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	536,000	33 %	570,500	35 %
Natural Gas	88,900	17 %	82,600	16 %

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The changes in PECO’s Operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)			Nine Months Ended September 30, 2018 Increase (Decrease)		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Weather	$20	$ 1	$21	$39	$ 19	$58
Volume	17	(1)	16	26	2	28
Pricing	(36)	3	(33)	(66)	(5)	(71)
Regulatory required programs	7	—	7	5	—	5
Other	3	—	3	18	(3)	15
Total increase	$11	$ 3	$14	$22	$ 13	$35

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 and nine months ended September 30, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel increased due to favorable weather conditions.

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, 2018 compared to the same period in 2017 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	From 2017	2018 vs. Normal
Heating Degree-Days	13	14	27	(7.1)%	(51.9)%
Cooling Degree-Days	1,124	989	999	13.7 %	12.5 %
Nine Months Ended September 30,					
Heating Degree-Days	2,892	2,437	2,912	18.7 %	(0.7)%
Cooling Degree-Days	1,506	1,404	1,383	7.3 %	8.9 %

Volume. Operating revenue net of purchased power related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2018 compared to the same period in 2017, increased due to the impact of moderate economic and customer growth partially offset by the impact of energy efficiency initiatives on customer usages primarily in the residential class. Additionally, the increase represents a shift in the volume profile across classes from the commercial and industrial classes to the residential class.

Pricing. Operating revenues net of purchased power as a result of pricing for the three and nine months ended September 30, 2018 and operating revenues net of fuel as the result of pricing for the nine months ended September 30, 2018 compared to the same periods in 2017 decreased primarily due to the pass back through customers rates the tax savings associated with the lower federal income

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tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency 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 Operating and maintenance expense, Depreciation and amortization expense and Income taxes. See Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Three Months Ended September 30, 2018	2017	Increase (Decrease)	Nine Months Ended September 30, 2018	2017	Increase (Decrease)
Operating and maintenance expense — baseline	$198	$183	$ 15	$632	$552	$ 80
Operating and maintenance expense — regulatory required programs[(a)]	21	14	7	54	43	11
Total Operating and maintenance expense	$219	$197	$ 22	$686	$595	$ 91

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(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (1)	$ 10
Storm-related costs[(a)]	2	61
Pension and non-pension postretirement benefits expense	(2)	(5)
Uncollectible accounts expense	6	8
Other	10	6
	15	80
Regulatory Required Programs		
Energy efficiency	7	11
Total increase	$ 22	$ 91

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(a) Reflects increased costs incurred from the Q1 2018 winter storms.

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Depreciation and Amortization Expense
Depreciation and amortization expense increased primarily due to ongoing capital spend for the three and nine months ended September 30, 2018 compared to the same period in 2017.
Taxes Other Than Income
Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income increased for the three and nine months ended September 30, 2018 compared to the same period in 2017 due to an increase in gross receipts tax driven by an increase in electric revenue.
Interest Expense, Net
Interest expense, net for the three and nine months ended September 30, 2018 remained relatively consistent compared to the same period in 2017.
Other, Net
Other, net for the three and nine months ended September 30, 2018 remained consistent compared to the same period in 2017.
Effective Income Tax Rate
PECO's effective income tax rate was (1.6)% and 20.0% for the three months ended September 30, 2018 and 2017, respectively. PECO's effective income tax rate was (1.5)% and 20.4% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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PECO Electric Operating Statistics

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	4,166	3,752	11.0 %	4.7 %	10,741	9,939	8.1 %	2.8 %
Small commercial & industrial	2,315	2,158	7.3 %	2.0 %	6,273	6,048	3.7 %	0.4 %
Large commercial & industrial	4,378	4,137	5.8 %	4.9 %	11,892	11,593	2.6 %	2.5 %
Public authorities & electric railroads	189	198	(4.5)%	(4.8)%	568	618	(8.1)%	(7.7)%
Total retail deliveries	11,048	10,245	7.8 %	4.0 %	29,474	28,198	4.5 %	1.9 %

Number of Electric Customers	As of September 30, 2018	2017
Residential	1,476,914	1,463,906
Small commercial & industrial	152,253	150,964
Large commercial & industrial	3,124	3,112
Public authorities & electric railroads	9,561	9,665
Total	1,641,852	1,627,647

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(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.

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PECO Natural Gas Operating Statistics

Deliveries to Customers (in mmcf)	Three Months Ended September 30,		% Change	Weather - Normal % Change	Nine Months Ended September 30,		% Change	Weather - Normal % Change
	2018	2017			2018	2017		
Retail Deliveries[a]								
Residential	2,099	2,177	(3.6)%	0.9%	28,562	24,866	14.9%	0.2%
Small commercial & industrial	1,776	1,814	(2.1)%	0.2%	15,792	13,944	13.3%	1.0%
Large commercial & industrial	6	2	200.0%	12.8%	58	15	286.7%	278.3%
Transportation	5,693	5,674	0.3%	3.2%	19,242	19,122	0.6%	(3.8)%
Total natural gas deliveries	9,574	9,667	(1.0)%	1.6%	63,654	57,947	9.8%	(0.8)%

Number of Natural Gas Customers	As of September 30, 2018	2017
Residential	479,732	474,766
Small commercial & industrial	43,638	43,352
Large commercial & industrial	1	6
Transportation	761	771
Total	524,132	518,895

(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.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.

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Results of Operations — BGE

	Three Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$731	$738	$ (7)	$2,369	$2,363	$ 6
Purchased power and fuel expense	272	269	(3)	881	853	(28)
Revenues net of purchased power and fuel expense[(a)]	459	469	(10)	1,488	1,510	(22)
Other operating expenses						
Operating and maintenance	182	175	(7)	578	532	(46)
Depreciation and amortization	110	109	(1)	358	348	(10)
Taxes other than income	64	61	(3)	188	180	(8)
Total other operating expenses	356	345	(11)	1,124	1,060	(64)
Gain on sales of assets	—	—	—	1	—	1
Operating income	103	124	(21)	365	450	(85)
Other income and (deductions)						
Interest expense, net	(27)	(26)	(1)	(78)	(80)	2
Other, net	5	4	1	14	12	2
Total other income and (deductions)	(22)	(22)	—	(64)	(68)	4
Income before income taxes	81	102	(21)	301	382	(81)
Income taxes	18	40	22	59	151	92
Net income	$63	$62	$ 1	$242	$231	$ 11

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. BGE's Net income for the three months ended September 30, 2018 was relatively consistent with the same period in 2017. The TCJA did not significantly impact BGE's net income for the three months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. BGE's Net income for the nine months ended September 30, 2018 was higher than the same period in 2017, due primarily to higher transmission revenues, partially offset by an increase in Operating and maintenance expense attributable to increased storm restoration costs as a result of storms in March 2018 and September 2018. The TCJA did not significantly impact BGE's net income for the nine months ended September 30, 2018 as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

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Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE’s electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC’s market-based SOS and gas commodity programs, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on Revenues net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive supplier for electricity and/or natural gas. All BGE customers have the choice to purchase electricity and natural gas from competitive suppliers. The customers' choice of suppliers does not impact the volume of deliveries but does affect revenue collected from customers related to supplied electricity and natural gas.

Retail deliveries purchased from competitive electricity and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2018 and 2017 consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	59 %	60 %	59 %	60 %
Natural Gas	76 %	74 %	56 %	57 %

The number of retail customers purchasing electricity and natural gas from competitive suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	335,200	26 %	339,300	27 %
Natural Gas	147,400	22 %	148,600	22 %

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The changes in BGE’s Operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018			Nine Months Ended September 30, 2018		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution revenue	$(17)	$(2)	$(19)	$(48)	$(19)	$(67)
Regulatory required programs	1	(1)	—	3	2	5
Transmission revenue	6	—	6	23	—	23
Other, net	—	3	3	6	11	17
Total decrease	$(10)	$—	$(10)	$(16)	$(6)	$(22)

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of fluctuations in actual consumption levels. This allows BGE to recognize revenue at MDPSC-approved distribution charges per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth (i.e., increase in the number of customers), it will not be affected by volatility in actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

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 BGE's service territory. The changes in heating and cooling degree-days in BGE's service territory for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	31	64	76	(51.6)%	(59.2)%
Cooling Degree-Days	733	595	601	23.2 %	22.0 %
Nine Months Ended September 30,					
Heating Degree-Days	2,969	2,524	2,974	17.6 %	(0.2)%
Cooling Degree-Days	1,032	877	857	17.7 %	20.4 %

Distribution Revenue. The decrease in distribution revenues for the three and nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to the impact of reduced distribution rates to reflect the lower federal income tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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Regulatory Required Programs. Revenue from regulatory required programs are billings for the costs of various legislative and/or regulatory programs that are recoverable from customers on a full and current basis. These programs are designed to provide full cost recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon rate adjustments to reflect fluctuations in the underlying costs, capital investments being recovered and other billing determinants. The increase in transmission revenue for the three and nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other, net revenue, which can vary from period to period, primarily includes assistance provided to other utilities through BGE's mutual assistance program, service application fees, and other miscellaneous revenue such as off-system sales and administrative charges.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense — baseline	$180	$172	$ 8	$572	$520	$ 52
Operating and maintenance expense — regulatory required programs (a)	2	3	(1)	6	12	(6)
Total Operating and maintenance expense	$182	$175	$ 7	$578	$532	$ 46

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Storm-related costs[a]	$ 5	$ 36
Labor, other benefits, contracting and materials	1	2
Uncollectible accounts expense	1	3
BSC costs	(1)	4
Other	2	7
	8	52
Regulatory Required Programs		
Other	(1)	(6)
Total increase	$ 7	$ 46

(a) Reflects increased storm restoration costs incurred from storms in Q1 2018 and Q3 2018.

Depreciation and Amortization

The changes in Depreciation and amortization expense for the three and nine months ended September 30, 2018, compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Depreciation expense[a]	$ 8	$ 17
Regulatory asset amortization[b]	(8)	(18)
Regulatory required programs[c]	1	11
Total increase	$ 1	$ 10

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

(b) Regulatory asset amortization decreased for the three and nine months ended September 30, 2018 compared to the same period in 2017 primarily due to certain regulatory assets that became fully amortized as of December 31, 2017. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and nine months ended September 30, 2018, compared to the same period in 2017, increased primarily due to an increase in property taxes.

Gain on Sales of Assets

Gain on sales of assets, for the three months ended September 30, 2018 compared to the same period in 2017, remained relatively consistent. The increase in Gain on sales of assets during the nine

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months ended September 30, 2018, compared to the same period in 2017, is due to the sale of land in June 2018.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018, compared to the same period in 2017, remained relatively consistent.

Other, Net

Other, net for the three and nine months ended September 30, 2018, compared to the same period in 2017, remained relatively consistent.

Effective Income Tax Rate

BGE’s effective income tax rate was 22.2% and 39.2% for the three months ended September 30, 2018 and 2017, respectively. BGE's effective income tax rate was 19.6% and 39.5% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three and nine months ended September 30, 2018, compared to the same periods in 2017, is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30,		% Change	Weather - Normal % Change	Nine Months Ended September 30,		% Change	Weather - Normal % Change
	2018	2017			2018	2017		
Retail Deliveries[a]								
Residential	3,663	3,370	8.7 %	1.8 %	9,960	9,126	9.1 %	1.8 %
Small commercial & industrial	825	785	5.1 %	(1.1)%	2,309	2,210	4.5 %	(0.2)%
Large commercial & industrial	3,909	3,781	3.4 %	0.6 %	10,661	10,422	2.3 %	(0.1)%
Public authorities & electric railroads	64	64	— %	(5.9)%	200	204	(2.0)%	(4.1)%
Total electric deliveries	8,461	8,000	5.8 %	0.9 %	23,130	21,962	5.3 %	0.7 %

	As of September 30,	
Number of Electric Customers	2018	2017
Residential	1,165,012	1,156,659
Small commercial & industrial	114,082	113,224
Large commercial & industrial	12,218	12,144
Public authorities & electric railroads	263	274
Total	1,291,575	1,282,301

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

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BGE Natural Gas Operating Statistics and Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	2,244	2,395	(6.3)%	(4.5)%	29,290	24,125	21.4 %	3.2 %
Small commercial & industrial	813	814	(0.1)%	0.4 %	7,020	5,667	23.9 %	7.2 %
Large commercial & industrial	8,227	8,012	2.7 %	2.2 %	34,044	30,828	10.4 %	5.9 %
Other[b]	3,144	68	4,523.5 %	n/a	11,183	2,463	354.0 %	n/a
Total natural gas deliveries	14,428	11,289	27.8 %	0.6 %	81,537	63,083	29.3 %	4.9 %

Number of Gas Customers	As of September 30, 2018	2017
Residential	631,589	626,039
Small commercial & industrial	38,175	38,141
Large commercial & industrial	5,920	5,832
Total	675,684	670,012

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

(b) Other natural gas revenue includes off-system sales of 3,144 mmcfs and 68 mmcfs for the three months ended September 30, 2018 and 2017, respectively. Other natural gas revenue includes off-system sales of 11,183 mmcfs and 2,463 mmcfs for the nine months ended September 30, 2018 and 2017. respectively.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

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Results of Operations — PHI

PHI's results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Operating revenues	$1,361	$1,310	$ 51	$3,688	$3,557	$ 131
Purchased power and fuel expense	509	473	(36)	1,410	1,318	(92)
Revenues net of purchased power and fuel expense[(a)]	852	837	15	2,278	2,239	39
Other operating expenses						
Operating and maintenance	292	251	(41)	857	774	(83)
Depreciation and amortization	192	179	(13)	555	511	(44)
Taxes other than income	123	122	(1)	343	344	1
Total other operating expenses	607	552	(55)	1,755	1,629	(126)
Gain on sales of assets	—	—	—	—	1	(1)
Operating income	245	285	(40)	523	611	(88)
Other income and (deductions)						
Interest expense, net	(65)	(62)	(3)	(193)	(183)	(10)
Other, net	11	13	(2)	33	40	(7)
Total other income and (deductions)	(54)	(49)	(5)	(160)	(143)	(17)
Income before income taxes	191	236	(45)	363	468	(105)
Income taxes	4	83	79	28	109	81
Equity in earnings of unconsolidated affiliate	—	—	—	1	—	1
Net income	$187	$153	$ 34	$336	$359	$ (23)

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(a) PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power and fuel expense 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.

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. PHI's Net income for the three months ended September 30, 2018 was $187 million compared to $153 million for the three months ended September 30, 2017.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $15 million for the three months ended September 30, 2018 compared to the same period in 2017 primarily due to higher utility revenues due to distribution rate increases at Pepco, DPL, and ACE, as well as favorable weather and volume, partially offset by lower revenues resulting from the pass back of TCJA tax savings through customer rates.

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Operating and maintenance expense increased by $41 million for the three months ended September 30, 2018 compared to the same period in 2017. The increase is primarily due to the following factors:

- Increase of $22 million at Pepco due to a charge associated with a remeasurement of the Buzzard Point ARO; and
- Increase of $14 million primarily due to deferral of accumulated merger integration costs as regulatory assets in 2017.

Depreciation and amortization expense for the three months ended September 30, 2018 compared to the same period in 2017 increased by $13 million primarily due to ongoing capital expenditures as well as increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues).

Taxes other than income for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Gain on sales of assets during the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Interest expense, net for the three months ended September 30, 2018 compared to the same period in 2017 increased by $3 million due to higher outstanding debt.

Other, net for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Equity in earnings for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

PHI's effective income tax rate was 2.1% and 35.2% for the three months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. PHI's Net income for the nine months ended September 30, 2018 was $336 million compared to $359 million for the nine months ended September 30, 2017.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $39 million for the nine months ended September 30, 2018 compared to the same period in 2017 primarily due to higher utility revenues due to distribution rate increases at Pepco, DPL, and ACE, as well as favorable weather and volume, partially offset by lower revenues resulting from the pass back of TCJA tax savings through customer rates.

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Operating and maintenance expense increased by $83 million for the nine months ended September 30, 2018 compared to the same period in 2017. The increase is primarily due to the following factors:

- Increase of $28 million primarily due to deferral of accumulated merger integration costs as regulatory assets in 2017;
- Net increase of $23 million in labor and contracting expense due to an increase of $32 million at Pepco, DPL and ACE partially offset by a decrease of $9 million at PHISCO as a result of the completion of integration transition activities; and
- Increase of $22 million at Pepco due to a charge associated with a remeasurement of the Buzzard Point ARO.

Depreciation and amortization expense for the nine months ended September 30, 2018 compared to the same period in 2017 increased by $44 million primarily due to ongoing capital expenditures as well as increased amortization of Pepco's DC PLUG regulatory asset (an equal and offsetting amount has been reflected in Operating revenues).

Taxes other than income for the nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Gain on sales of assets during the nine months ended September 30, 2018 compared to the same period in 2017 decreased $1 million due to the sale of land in June 2017.

Interest expense, net for the nine months ended September 30, 2018 compared to the same period in 2017 increased $10 million due to higher outstanding debt.

Other, net for the nine months ended September 30, 2018 compared to the same period in 2017 decreased $7 million primarily due to lower income from AFUDC equity.

Equity in earnings for the nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

PHI's effective income tax rate was 7.7% and 23.3% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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Results of Operations - Pepco

	Three Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$628	$604	$ 24	$1,708	$1,649	$ 59
Purchased power expense	177	168	(9)	497	478	(19)
Revenues net of purchased power expense[(a)]	451	436	15	1,211	1,171	40
Other operating expenses						
Operating and maintenance	136	103	(33)	383	336	(47)
Depreciation and amortization	99	82	(17)	286	242	(44)
Taxes other than income	104	102	(2)	288	282	(6)
Total other operating expenses	339	287	(52)	957	860	(97)
Gain on sales of assets	—	—	—	—	1	(1)
Operating income	112	149	(37)	254	312	(58)
Other income and (deductions)						
Interest expense, net	(32)	(31)	(1)	(96)	(89)	(7)
Other, net	7	7	—	23	22	1
Total other income and (deductions)	(25)	(24)	(1)	(73)	(67)	(6)
Income before income taxes	87	125	(38)	181	245	(64)
Income taxes	(2)	38	40	7	57	50
Net income	$89	$87	$ 2	$174	$188	$ (14)

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense 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.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. Pepco's Net income for the three months ended September 30, 2018, was relatively consistent with the same period in 2017. The TCJA did not significantly impact Pepco's Net income for the three months ended September 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. Pepco's Net income for the nine months ended September 30, 2018, was lower than the same period in 2017 primarily due to higher Operating and maintenance expense attributable to an increase in the asset retirement obligations related to the Buzzard Point property, deferral of accumulated merger integration costs as regulatory assets in 2017 and higher regulatory asset amortization due to additional regulatory assets related to rate case activity, partially offset by higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and June 2018 and higher electric distribution base rates charged to customers in the District of Columbia that became effective August 2017 and August 2018. The TCJA did not significantly impact Pepco's Net income for the nine

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months ended September 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology. Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	64 %	65 %	64 %	66 %

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	175,838	20 %	179,106	21 %

Retail deliveries purchased from competitive electric generation suppliers represented 72% and 72% of Pepco's retail kWh sales to the District of Columbia customers and 58% and 58% of Pepco's retail kWh sales to Maryland customers for the three and nine months ended September 30, 2018, respectively and 72% and 73% of Pepco's retail kWh sales to the District of Columbia customers and 60% and 60% of Pepco's retail kWh sales to Maryland customers for the three and nine months ended September 30, 2017, respectively.

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The changes in Pepco’s operating revenues net of purchased power expense for the three and nine months ended September 30, 2018 compared to the same periods in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Volume	$ 3	$ 9
Distribution revenue	6	9
Regulatory required programs	7	27
Transmission revenue	2	(5)
Other	(3)	—
Total increase	$ 15	$ 40

Revenue Decoupling. Pepco’s results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

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 Pepco's service territory. The changes in heating and cooling degree-days in Pepco’s service territory for the three and nine months ended September 30, 2018 compared to the same periods in 2017 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	2	8	13	(75.0)%	(84.6)%
Cooling Degree-Days	1,283	1,130	1,137	13.5 %	12.8 %
Nine Months Ended September 30,					
Heating Degree-Days	2,458	1,963	2,448	25.2 %	0.4 %
Cooling Degree-Days	1,861	1,679	1,626	10.8 %	14.5 %

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2018 compared to the same periods in 2017, primarily reflects the impact of residential customer growth.

Distribution Revenue. The increase in distribution revenues for the three and nine months ended September 30, 2018 compared to the same periods in 2017 was primarily due to higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and June 2018 and higher electric distribution base rates charged to customers in the District of Columbia that became

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effective August 2017 and August 2018, partially offset by the impact of reduced distribution rates to reflect the lower federal income tax rate. See Note 6—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in Pepco's Consolidated Statements of Operations and Comprehensive Income. See Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs. Revenue from regulatory required programs increased for the three and nine months ended September 30, 2018 compared to the same periods in 2017 due to increases in the Maryland and District of Columbia surcharge rates and sales due to higher volumes, as well as the DC PLUG surcharge which became effective in February 2018.

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, the highest daily peak load and other billing adjustments. The increase in transmission revenue for the three months ended September 30, 2018 compared to the same period in 2017 is a result of higher rates effective June 2018. The decrease in transmission revenue for the nine months ended September 30, 2018 is a result of a decrease in network transmission service peak loads, partially offset by higher rates effective June 2018.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

Operating and Maintenance Expense

	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Increase (Decrease)	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017	Increase (Decrease)
Operating and maintenance expense - baseline	$133	$99	$ 34	$374	$326	$ 48
Operating and maintenance expense - regulatory required programs[a]	3	4	(1)	9	10	(1)
Total operating and maintenance expense	$136	$103	$ 33	$383	$336	$ 47

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same periods in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
ARO update[(a)]	22	22
Merger costs[(b)]	8	14
Labor and contracting[(c)]	(2)	3
Other	6	9
	34	48
Regulatory required programs	(1)	(1)
Total increase	$ 33	$ 47

(a) Reflects an increase primarily related to asbestos identified at the Buzzard Point property. See Note 13 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Primarily due to a deferral of accumulated merger integration costs as regulatory assets in 2017.
(c) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 3	$ 8
Regulatory asset amortization[(b)]	10	16
Regulatory required programs[(c)]	4	20
Total increase	$ 17	$ 44

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased primarily due to additional regulatory assets related to rate case activity. Regulatory required programs increased as a result of higher amortization of the DC PLUG regulatory asset.
(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Taxes other than income for the nine months ended September 30, 2018 compared to the same period in 2017, increased due to an increase in the utility taxes that are collected and passed through by Pepco (which is substantially offset in Operating revenues).

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Gain on Sales of Assets

The decrease in Gain on sales of assets during the nine months ended September 30, 2018, compared to the same period in 2017, is primarily due to the sale of land in June 2017.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018 compared to the same periods in 2017 increased due to higher outstanding debt.

Other, Net

Other, net for the three and nine months ended September 30, 2018 compared to the same periods in 2017 remained relatively consistent.

Effective Income Tax Rate

Pepco's effective income tax rate was (2.3)% and 30.4% for the three months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA.

Pepco's effective income tax rate was 3.9% and 23.3% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

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Pepco Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30,			Weather - Normal % Change	Nine Months Ended September 30,			Weather - Normal % Change
	2018	2017	% Change		2018	2017	% Change	
Retail Deliveries[a]								
Residential	2,446	2,281	7.2 %	1.4 %	6,528	6,038	8.1 %	0.1 %
Small commercial & industrial	327	347	(5.8)%	(8.1)%	982	999	(1.7)%	(4.8)%
Large commercial & industrial	4,298	4,146	3.7 %	1.3 %	11,661	11,306	3.1 %	1.0 %
Public authorities & electric railroads	181	180	0.6 %	— %	531	542	(2.0)%	(2.6)%
Total retail deliveries	7,252	6,954	4.3 %	0.8 %	19,702	18,885	4.3 %	0.3 %

Number of Electric Customers	As of September 30,	
	2018	2017
Residential	802,607	790,032
Small commercial & industrial	53,700	53,543
Large commercial & industrial	21,927	21,733
Public authorities & electric railroads	147	143
Total	878,381	865,451

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

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

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Results of Operations - DPL

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Operating revenues	$328	$327	$ 1	$1,001	$971	$ 30
Purchased power and fuel expense	133	129	(4)	425	399	(26)
Revenues net of purchased power and fuel expense[(a)]	195	198	(3)	576	572	4
Other operating expenses						
Operating and maintenance	82	79	(3)	256	227	(29)
Depreciation and amortization	47	45	(2)	135	124	(11)
Taxes other than income	15	15	—	43	43	—
Total other operating expenses	144	139	(5)	434	394	(40)
Operating income	51	59	(8)	142	178	(36)
Other income and (deductions)						
Interest expense, net	(15)	(13)	(2)	(42)	(38)	(4)
Other, net	2	4	(2)	7	10	(3)
Total other income and (deductions)	(13)	(9)	(4)	(35)	(28)	(7)
Income before income taxes	38	50	(12)	107	150	(43)
Income taxes	5	19	14	17	43	26
Net income	$33	$31	$ 2	$90	$107	$ (17)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for natural gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense 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.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. DPL's Net income for the three months ended September 30, 2018, remained relatively consistent with the same period in 2017. The TCJA did not significantly impact DPL's Net income for the three months ended September 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. DPL's Net income for the nine months ended September 30, 2018, was lower than the same period in 2017 primarily due to higher Operating and maintenance expense attributable to higher labor and contracting expense, deferral of accumulated merger integration costs as regulatory assets in 2017 and higher regulatory asset amortization due to additional regulatory assets related to rate case activity, partially offset by higher electric distribution base rates and higher gas distribution interim base rates charged to customers in Delaware that were put into effect in March 2018 and favorable weather and volumes. The TCJA did not significantly impact DPL's Net income for the nine months ended September 30, 2018 as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

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Revenues Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity and natural gas to DPL’s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology. Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural gas operating revenue includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Electric and natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2018 and 2017, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	50 %	51 %	50 %	52 %
Natural Gas	53 %	53 %	33 %	35 %

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	72,622	13.8 %	78,426	15.0 %
Natural Gas	154	0.1 %	155	0.1 %

Retail deliveries purchased from competitive electric generation suppliers represented 52% and 52% of DPL’s retail kWh sales to Delaware customers and 46% and 45% of DPL's retail kWh sales to Maryland customers for the three and nine months ended September 30, 2018, respectively and 53% and 54% of DPL's retail kWh sales to Delaware customers and 48% and 48% of DPL's retail kWh sales to Maryland customers for the three and nine months ended September 30, 2017, respectively.

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The changes in DPL's Operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)			Nine Months Ended September 30, 2018 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$4	$(1)	$3	$10	$4	$14
Volume	1	2	3	4	3	7
Distribution revenue	(8)	1	(7)	(18)	(1)	(19)
Regulatory required programs	(3)	(2)	(5)	(3)	(1)	(4)
Transmission revenue	5	—	5	5	—	5
Other	(2)	—	(2)	1	—	1
Total increase	$(3)	$—	$(3)	$(1)	$5	$4

Revenue Decoupling. DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

Weather. The demand for electricity and natural gas in areas not subject to the BSA 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 and nine months ended September 30, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel expense related to weather was higher due to the impact of favorable weather conditions in DPL's Delaware service territory.

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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 electric service territory and a 30-year period in DPL's natural gas service territory. The changes in heating and cooling degree-days in DPL’s service territory for the three and nine months ended September 30, 2018 compared to the same period in 2017 and normal weather consisted of the following:

Electric Service Territory				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	7	24	31	(70.8)%	(77.4)%
Cooling Degree-Days	1,052	867	863	21.3 %	21.9 %
Nine Months Ended September 30,					
Heating Degree-Days	2,882	2,476	2,906	16.4 %	(0.8)%
Cooling Degree-Days	1,425	1,228	1,199	16.0 %	18.8 %

Natural Gas Service Territory				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	11	28	42	(60.7)%	(73.8)%
Nine Months Ended September 30,					
Heating Degree-Days	2,995	2,571	3,042	16.5 %	(1.5)%

Volume. The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2018 compared to the same period in 2017, primarily reflects the impact of increased average residential customer usage and growth.

Distribution Revenue. The decrease in electric distribution revenue for the three months ended September 30, 2018, and electric and gas distribution revenue for the nine months ended September 30, 2018 compared to the same periods in 2017 was primarily due to reduced electric distribution rates and gas interim distribution rates in Delaware that were put into effect in March 2018 which reflect the impact of the lower federal income tax rate. The increase in gas distribution revenue for the three months ended September 30, 2018 compared to the same period in 2017 is primarily due to customer sales mix. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in Operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in DPL's Consolidated Statements of Operations and Comprehensive Income. See Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs. Revenue from regulatory required programs decreased for the three and nine months ended September 30, 2018 compared to the same periods in 2017 primarily due to decreases of surcharge rates.

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, the highest daily peak load and other billing adjustments. The increase in transmission revenue for the three

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and nine months ended September 30, 2018 compared to the same period in 2017 is a result of a higher rates effective June 2018.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

Operating and Maintenance Expense

	Three Months Ended September 30, 2018	2017	Increase (Decrease)	Nine Months Ended September 30, 2018	2017	Increase (Decrease)
Operating and maintenance expense - baseline	$ 78	$ 74	$ 4	$ 244	$ 215	$ 29
Operating and maintenance expense - regulatory required programs[(a)]	4	5	(1)	12	12	—
Total operating and maintenance expense	$ 82	$ 79	$ 3	$ 256	$ 227	$ 29

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Labor and contracting[(a)]	$ 2	$ 11
Uncollectible accounts expense	2	4
Merger costs[(b)]	(2)	7
Other	2	7
	4	29
Regulatory required programs	(1)	—
Total increase	$ 3	$ 29

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) Primarily due to a deferral of accumulated merger integration costs as regulatory assets in 2017.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 2	$ 5
Regulatory asset amortization[(b)]	3	10
Regulatory required programs[(c)]	(3)	(4)
Total increase	$ 2	$ 11

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

(b) Regulatory asset amortization increased due to additional regulatory assets related to rate case activity.

(c) Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 increased due to higher outstanding debt.

Other, Net

Other, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Effective Income Tax Rate

DPL's effective income tax rate was 13.2% and 38.0% for the three months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA.

DPL's effective income tax rate was 15.9% and 28.7% for the nine months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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DPL Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	1,537	1,439	6.8 %	— %	4,203	3,843	9.4 %	1.7 %
Small commercial & industrial	651	636	2.4 %	(0.1)%	1,756	1,693	3.7 %	1.5 %
Large commercial & industrial	1,282	1,245	3.0 %	0.2 %	3,548	3,440	3.1 %	1.3 %
Public authorities & electric railroads	11	10	10.0 %	8.9 %	33	35	(5.7)%	(5.3)%
Total retail deliveries	3,481	3,330	4.5 %	0.1 %	9,540	9,011	5.9 %	1.5 %

Number of Electric Customers	As of September 30, 2018	2017
Residential	463,017	458,790
Small commercial & industrial	61,277	60,542
Large commercial & industrial	1,400	1,406
Public authorities & electric railroads	622	633
Total	526,316	521,371

(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.

DPL Natural Gas Operating Statistics and Detail

Retail Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	360	331	8.8 %	16.6 %	5,801	4,785	21.2 %	4.8 %
Small commercial & industrial	309	290	6.6 %	11.3 %	2,831	2,486	13.9 %	(1.0)%
Large commercial & industrial	454	448	1.3 %	1.3 %	1,438	1,408	2.1 %	2.2 %
Transportation	1,260	1,197	5.3 %	5.6 %	4,893	4,690	4.3 %	1.8 %
Total natural gas deliveries	2,383	2,266	5.2 %	7.2 %	14,963	13,369	11.9 %	2.4 %

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	As of September 30,	
Number of Gas Customers	2018	2017
Residential	123,145	121,238
Small commercial & industrial	9,798	9,683
Large commercial & industrial	19	17
Transportation	154	155
Total	133,116	131,093

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

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

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Results of Operations - ACE

	Three Months Ended September 30,		Favorable (Unfavorable) Variance	Nine Months Ended September 30,		Favorable (Unfavorable) Variance
	2018	2017		2018	2017	
Operating revenues	$406	$370	$ 36	$981	$915	$ 66
Purchased power expense	198	176	(22)	486	442	(44)
Revenues net of purchased power expense[a]	208	194	14	495	473	22
Other operating expenses						
Operating and maintenance	85	72	(13)	250	225	(25)
Depreciation and amortization	38	41	3	107	113	6
Taxes other than income	1	2	1	4	6	2
Total other operating expenses	124	115	(9)	361	344	(17)
Operating income	84	79	5	134	129	5
Other income and (deductions)						
Interest expense, net	(16)	(15)	(1)	(48)	(46)	(2)
Other, net	1	1	—	2	6	(4)
Total other income and (deductions)	(15)	(14)	(1)	(46)	(40)	(6)
Income before income taxes	69	65	4	88	89	(1)
Income taxes	8	24	16	12	12	—
Net income	$61	$41	$ 20	$76	$77	$ (1)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense 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.

Net Income

Three Months Ended September 30, 2018 Compared to Three Months Ended September 30, 2017. ACE's Net income for the three months ended September 30, 2018, was higher than the same period in 2017, primarily due to higher electric distribution base rates charged to customers in New Jersey that became effective in October 2017, as well as favorable weather and volume. The TCJA did not significantly impact ACE’s Net income for the three months ended September 30, 2018 as the favorable income tax impacts were predominately offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Nine Months Ended September 30, 2018 Compared to Nine Months Ended September 30, 2017. ACE's Net income for the nine months ended September 30, 2018, remained relatively consistent with the same period in 2017. The TCJA did not significantly impact ACE’s Net income for the nine months ended September 30, 2018 as the favorable income tax impacts were predominately offset by lower revenues resulting from the pass back of the tax savings through customer rates.

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Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE’s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology. Operating revenues also include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM wholesale markets for energy and capacity purchased under contacts with unaffiliated NUGs, and revenue from transmission enhancement credits. Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer's choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Electric	43 %	44 %	46 %	48 %

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2018 and 2017 consisted of the following:

	September 30, 2018		September 30, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	82,556	15 %	91,219	17 %

The changes in ACE’s operating revenue net of purchased power expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Weather	$ 8	$ 12
Volume	7	13
Distribution revenue	6	12
Regulatory required programs	(4)	(14)
Transmission revenue	(4)	(3)
Other	1	2
Total increase	$ 14	$ 22

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Weather. The demand for electricity is 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 and nine months ended September 30, 2018 compared to the same period in 2017, operating revenue net of purchased power and fuel expense related to weather was higher due to the impact of favorable weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled from the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE'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 20-year period in ACE’s service territory. The changes in heating and cooling degree-days in ACE’s service territory for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	1	23	39	(95.7)%	(97.4)%
Cooling Degree-Days	1,093	830	817	31.7 %	33.8 %
Nine Months Ended September 30,					
Heating Degree-Days	2,928	2,608	3,068	12.3 %	(4.6)%
Cooling Degree-Days	1,447	1,153	1,110	25.5 %	30.4 %

Volume. During the three and nine months ended September 30, 2018 compared to the same period in 2017 the increase in operating revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, is primarily due to higher average residential and commercial usage.

Distribution Revenue. The increase in distribution revenue for the three and nine months ended September 30, 2018 compared to the same period in 2017 was primarily due to higher electric distribution base rates charged to customers that became effective in November 2017, partially offset by the impact of reduced distribution rates to reflect the lower federal income tax rate. See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in ACE's Consolidated Statements of Operations and Comprehensive Income. See Operating and maintenance expense and Depreciation and amortization expense discussion below for additional information on included programs. Revenue from regulatory required programs decreased for the three and nine months ended September 30, 2018 compared to the same periods in 2017 due to a rate decrease effective October 2017 for the ACE Transition Bonds.

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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, the highest daily peak load and other billing adjustments. The decrease in transmission revenue for the three and nine months ended September 30, 2018 compared to the same periods in 2017 was primarily due to the impact of the lower federal income tax rate.

Other. Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, and recoveries of other taxes.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase (Decrease)	Nine Months Ended September 30,		Increase (Decrease)
	2018	2017		2018	2017	
Operating and maintenance expense - baseline	$ 69	$ 62	$ 7	$ 227	$ 199	$ 28
Operating and maintenance expense - regulatory required programs[a]	16	10	6	23	26	(3)
Total operating and maintenance expense	$ 85	$ 72	$ 13	$ 250	$ 225	$ 25

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Baseline		
Labor and contracting[a]	$ 7	$ 18
Merger costs[b]	8	7
Other	(8)	3
	7	28
Regulatory required programs	6	(3)
Total increase	$ 13	$ 25

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) Primarily due to a deferral of accumulated merger integration costs as regulatory assets in 2017.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three and nine months ended September 30, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended September 30, 2018 Increase (Decrease)	Nine Months Ended September 30, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 1	$ 4
Regulatory asset amortization	2	5
Regulatory required programs[(b)]	(6)	(15)
Total decrease	$ (3)	$ (6)

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

(b) Regulatory required programs decreased as a result of lower revenue due to rate decreases effective October 2017 for the ACE Transition Bonds. Depreciation and amortization expenses for regulatory required programs are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

Taxes Other Than Income

Taxes other than income for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent.

Other, Net

Other, net for the three months ended September 30, 2018 compared to the same period in 2017 remained relatively consistent. The decrease in Other, net for the nine months ended September 30, 2018 compared to the same period in 2017 was primarily due to lower income from AFUDC equity.

Effective Income Tax Rate

ACE's effective income tax rate was 11.6% and 36.9% for the three months ended September 30, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended September 30, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA.

ACE's effective income tax rate was 13.6% and 13.5% for the nine months ended September 30, 2018 and 2017, respectively. The increase in the effective income tax rate for the nine months ended September 30, 2018 compared to the same period in 2017 is primarily due to the absence of an unrecognized tax benefit from 2017, partially offset by a nonrecurring adjustment to income tax reserve balances in 2017.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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ACE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	1,548	1,349	14.8 %	6.2 %	3,363	3,042	10.6 %	4.3 %
Small commercial & industrial	442	407	8.6 %	4.0 %	1,066	992	7.5 %	4.3 %
Large commercial & industrial	1,030	939	9.7 %	6.7 %	2,725	2,557	6.6 %	5.0 %
Public authorities & electric railroads	10	9	11.1 %	8.2 %	36	33	9.1 %	8.2 %
Total retail deliveries	3,030	2,704	12.1 %	6.0 %	7,190	6,624	8.5 %	4.6 %

Number of Electric Customers	As of September 30, 2018	2017
Residential	489,961	486,212
Small commercial & industrial	61,141	60,982
Large commercial & industrial	3,569	3,726
Public authorities & electric railroads	656	633
Total	555,327	551,553

(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.

See Note 19 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

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Liquidity and Capital Resources

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

The Registrants' operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each 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 unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $545 million in bilateral facilities with banks which have various expirations between January 2019 and March 2020. 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 other postretirement benefit 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, ComEd, PECO, BGE, Pepco, DPL and ACE 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 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are 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 13 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

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 fund investments could appreciate in value. A shortfall could require that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantees or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the decommissioning trust fund investment performance going forward. Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. As discussed in Note 13 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements, Generation filed its annual decommissioning funding status report with the NRC on March 28, 2018 for shutdown reactors and reactors within five years of shut down. As of September 30, 2018, across the alternative

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decommissioning approaches available, Exelon would not be required to post a parental guarantee for TMI or Oyster Creek. In the event PSEG decides to early retire Salem, Generation estimates a parental guarantee of up to $55 million from Exelon could be required for Salem, dependent upon the ultimate decommissioning approach selected.

Upon issuance of any required financial guarantees, 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, the NRC must approve an additional exemption in order for the plant's owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e., spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the DOE reimbursement agreements or future litigation, across the four alternative decommissioning approaches available, if TMI or Oyster Creek were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $200 million and $215 million net of taxes, respectively, dependent upon the ultimate decommissioning approach selected. In the event PSEG decides to early retire Salem and Salem were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $95 million net of taxes.

On July 31, 2018, Generation entered into an agreement for the sale of Oyster Creek which is expected to occur in the second half of 2019. See Note 4 - Mergers, Acquisitions and Dispositions for additional information on the sale of Oyster Creek to Holtec.

Cash Flows from Operating Activities

General

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.

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, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 — Regulatory Matters and 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2017 Form 10-K for additional information of regulatory and legal proceedings and proposed legislation.

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The following table provides a summary of the major items affecting Exelon's cash flows from operations for the nine months ended September 30, 2018 and 2017:

	Nine Months Ended September 30, 2018	2017	Variance
Net income	$ 1,979	$ 1,928	$ 51
Add (subtract):			
Non-cash operating activities[(a)]	5,452	5,016	436
Pension and non-pension postretirement benefit contributions	(362)	(344)	(18)
Income taxes	166	167	(1)
Changes in working capital and other noncurrent assets and liabilities[(b)]	(746)	(1,029)	283
Option premiums received (paid), net	(36)	35	(71)
Collateral (posted) received, net	222	(100)	322
Net cash flows provided by operations	$ 6,675	$ 5,673	$ 1,002

(a) Represents depreciation, amortization and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, gain on sale of assets and businesses and other non-cash charges. See Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information on non-cash operating activity.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Exelon's funding strategy for its qualified pension plans is to contribute the greater of (1) $300 million (inclusive of PHI) and (2) the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon's non-qualified pension plans are not funded given that they are not subject to statutory minimum contribution requirements.

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

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

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On October 3, 2017, the U.S. Department of Treasury and IRS released final regulations updating the mortality tables to be used for defined benefit pension plan funding, as well as the valuation of lump sum and other accelerated distribution options, effective for plan years beginning in 2018. The new mortality tables reflect improved projected life expectancy as compared to the existing table, which is generally expected to increase minimum pension funding requirements, Pension Benefit Guaranty Corporation premiums and the value of lump sum distributions. The IRS permits plan sponsors the option of delaying use of the new mortality tables for determining minimum funding requirements until 2019, which Exelon has utilized. The one-year delay does not apply for use of the mortality tables to determine the present value of lump sum distributions.

Tax Matters

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

- Pursuant to the TCJA, beginning in 2018 Generation is expected to have higher operating cash flows in the range of approximately $1.2 billion to $1.6 billion for the period from 2018 to 2021, reflecting the reduction in the corporate federal income tax rate and full expensing of capital investments.

The TCJA is generally expected to result in lower operating cash flows for the Utility Registrants as a result of the elimination of bonus depreciation and lower customer rates. Increased operating cash flows for the Utility Registrants from lower corporate federal income tax rates is expected to be more than offset over time by lower customer rates resulting from lower income tax expense recoveries and the settlement of deferred income tax net regulatory liabilities established pursuant to the TCJA, partially offset by the impacts of higher rate base. The amount and timing of settlement of the net regulatory liabilities will be determined by the Utility Registrants' respective rate regulators, subject to certain IRS "normalization" rules. The table below sets forth the Registrants' estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

	Exelon	ComEd	PECO[(a)]	BGE	PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$3,040	$1,400	$533	$459	$648	$299	$195	$153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$4,734	$1,973	$576	$783	$1,402	$690	$389	$323

(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants. See Note 6 - Regulatory Matters for additional information.

Net regulatory liability amounts subject to normalization rules generally may not be passed back to customers any faster than over the remaining useful lives of the underlying assets giving rise to the associated deferred income taxes. Such deferred income taxes generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the remaining amounts, the pass back period is subject to determinations by the rate regulators.

The Utility Registrants expect to fund any such required incremental operating cash outflows using a combination of third party debt financings and equity funding from Exelon in combinations generally consistent with existing capitalization ratio structures. To fund any

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additional equity contributions to the Utility Registrants, Exelon would have available to it its typical sources, including, but not limited to, the increased operating cash flows at Generation referenced above, which over time are expected to exceed the incremental equity needs at the Utility Registrants.
The Utility Registrants have worked with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers. See Note 6 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on their filings.
See Note 12 - Income Taxes of the Combined Notes to Consolidated Financial Information for additional information on the amounts of the net regulatory liabilities subject to determinations by rate regulators.
At this time, many of the states in which Exelon does business have issued guidance regarding TCJA and the impact is not material.

- State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax, property taxes and other taxes or the imposition, extension or permanence of temporary tax increases.

Cash flows from operations for the nine months ended September 30, 2018 and 2017 by Registrant were as follows:

	Nine Months Ended September 30,	
	2018	2017
Exelon	$6,675	$5,673
Generation	3,411	2,270
ComEd	1,118	1,120
PECO	492	603
BGE	675	701
PHI	845	795
Pepco	396	348
DPL	292	292
ACE	160	158

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, 2018 and 2017 were as follows:
Generation

- 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 OTC markets. During the nine months ended September 30, 2018 and 2017, Generation had net collections/(payments) of counterparty cash collateral of $228 million and $(77) million, respectively, primarily due to market conditions that resulted in changes to Generation’s net mark-to-market position.

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- During the nine months ended September 30, 2018 and 2017, Generation had net (payments)/collections of approximately $(36) million and $35 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

See Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information regarding changes in non-cash operating activities.

Cash Flows from Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2018 and 2017 by Registrant were as follows:

	Nine Months Ended September 30,	
	2018	2017
Exelon	$(5,609)	$(5,743)
Generation	(1,806)	(1,875)
ComEd	(1,518)	(1,681)
PECO	(609)	(457)
BGE	(659)	(609)
PHI	(986)	(990)
Pepco	(472)	(438)
DPL	(253)	(293)
ACE	(248)	(242)

Significant investing cash flow impacts for the Registrants for nine months ended September 30, 2018 and 2017 were as follows:

Exelon

- During the nine months ended September 30, 2018, Exelon had proceeds of $85 million relating to the sale of its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution services.
- During the nine months ended September 30, 2018, Exelon had expenditures of $57 million relating to the acquisition of the Handley Generating Station.
- During the nine months ended September 30, 2017, Exelon had expenditures of $23 million and $178 million relating to the acquisitions of ConEdison Solutions and the FitzPatrick facility, respectively.
- During the nine months ended September 30, 2017, Exelon had proceeds of $218 million from sales of long-lived assets.

Capital Expenditure Spending

Generation

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Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technologies. The agreements contain a series of scheduled investment commitments, including in-kind service contributions. There are anticipated expenditures remaining to fund anticipated planned capital and operating needs of the associated companies.

Capital expenditures by Registrant for the nine months ended September 30, 2018 and 2017 and projected amounts for the full year 2018 are as follows:

	Projected Full Year 2018[(a)]		Nine Months Ended September 30, 2018	2017
Exelon	$ 7,850	[(b)]	$5,497	$5,556
Generation	2,325		1,660	1,654
ComEd[(c)]	2,125		1,540	1,698
PECO	850		615	537
BGE	1,000		667	615
PHI	1,500	[(d)]	988	995
Pepco	700		475	439
DPL	400		254	294
ACE	400		247	242

(a) Total projected capital expenditures do not include adjustments for non-cash activity. Amounts are rounded to the nearest $25 million.

(b) Includes corporate operations, BSC, and PHISCO.

(c) The capital expenditures and 2018 projections include approximately $81 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten-year period, through 2021, to modernize and storm-harden its distribution system and to implement smart grid technology.

(d) Includes PHISCO.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 40% and 10% of the projected 2018 capital expenditures at Generation are for the acquisition of nuclear fuel, and the construction of new natural gas plant and solar facilities, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Projected 2018 capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd’s reliability related investments required under EIMA, and the Utility Registrants' construction commitments under PJM’s RTEP.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform

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assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd and PECO will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's and PECO's forecasted 2018 capital expenditures above reflect capital spending for remediation to be completed through 2019. DPL, ACE, and BGE are complete with their assessments and Pepco has substantially completed its assessment and thus do not expect significant capital expenditures related to this guidance in 2018.
The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the nine months ended September 30, 2018 and 2017 by Registrant were as follows:

	Nine Months Ended September 30,	
	2018	2017
Exelon	$65	$701
Generation	(820)	(297)
ComEd	536	812
PECO	(51)	121
BGE	82	(112)
PHI	260	161
Pepco	83	199
DPL	69	(42)
ACE	94	(13)

Debt

See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt issuances.

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Dividends

Cash dividend payments and distributions during the nine months ended September 30, 2018 and 2017 by Registrant were as follows:

	Nine Months Ended September 30, 2018	2017
Exelon	$999	$921
Generation	688	494
ComEd	345	316
PECO	300	216
BGE	157	148
PHI	232	267
Pepco	128	133
DPL	58	82
ACE	46	53

Quarterly dividends declared by the Exelon Board of Directors during the nine months ended September 30, 2018 and for the third quarter of 2018 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share(a)
First Quarter 2018	January 30, 2018	February 15, 2018	March 9, 2018	$0.3450
Second Quarter 2018	May 1, 2018	May 15, 2018	June 8, 2018	$0.3450
Third Quarter 2018	July 24, 2018	August 15, 2018	September 10, 2018	$0.3450
Fourth Quarter 2018	September 24, 2018	November 15, 2018	December 10, 2018	$0.3450

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during the nine months ended September 30, 2018 and 2017 by Registrant were as follows:

	Nine Months Ended September 30, 2018	2017
Exelon	$(93)	$(559)
Generation	—	(609)
ComEd	—	—
PECO	—	—
BGE	(77)	(45)
PHI	(16)	(404)
Pepco	38	(23)
DPL	(216)	54
ACE	162	65

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Contributions from Parent/Member

Contributions received from Parent/Member for the nine months ended September 30, 2018 and 2017 by Registrant were as follows:

	Nine Months Ended September 30,	
	2018	2017
Generation	$54	$102
ComEd[(a)(b)]	387	567
PECO[(b)]	71	16
BGE [(b)]	18	77
PHI[(b)]	237	758
Pepco[(c)]	85	161
DPL[(c)]	150	—

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA and transmission upgrades.

(b) Contribution paid by Exelon.

(c) Contribution paid by PHI.

Other

For the nine months ended September 30, 2018, other financing activities primarily consist of debt issuance costs. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt issuances.

Credit Matters

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 $9.5 billion in aggregate total commitments of which $8.0 billion was available as of September 30, 2018, 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 market during the third quarter of 2018 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants 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 2017 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, 2018, it would have been required to provide incremental collateral of $1.8 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 its current available credit facility capacities of $4.4 billion.

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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, 2018 and available credit facility capacity prior to any incremental collateral at September 30, 2018:

	PJM Credit Policy Collateral	Other Incremental Collateral Required(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 8	$ —	$ 998
PECO	1	22	600
BGE	12	31	599
Pepco	11	—	296
DPL	5	10	300
ACE	—	—	300

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

Exelon Credit Facilities

Exelon Corporate, ComEd, BGE, Pepco, DPL and ACE 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 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.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at September 30, 2018:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size(a)(b)(c)	Outstanding Commercial Paper at September 30, 2018	Average Interest Rate on Commercial Paper Borrowings for the Nine Months Ended September 30, 2018
Exelon Corporate	$ 600	$ —	1.93 %
Generation	5,300	—	1.96 %
ComEd	1,000	—	2.14 %
PECO	600	—	2.24 %
BGE	600	—	2.15 %
Pepco	500	64	2.19 %
DPL	500	—	2.07 %
ACE	350	145	2.15 %

(a) Excludes $545 million bilateral credit facilities that do not back Generation's commercial paper program.

(b) Excludes $128 million of credit facility agreements arranged at minority and community banks at Generation, PECO, ComEd, BGE, Pepco, DPL and ACE. These facilities expired on October 12, 2018 and were renewed with aggregate commitments of $49 million, $33.5 million, $32.5 million, $5 million, $5 million, $5 million, and $5 million, respectively, through October 11, 2019. These facilities are solely utilized to issue letters of credit. As of September 30, 2018, letters of credit issued under these agreements for Generation and BGE totaled $5 million and $2 million, respectively.

(c) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the

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maximum amount of short-term debt the Registrant is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility. At September 30, 2018, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

					Available Capacity at September 30, 2018	
Borrower	Facility Type	Aggregate Bank Commitment[(a)]	Facility Draws	Outstanding Letters of Credit[(c)]	Actual	To Support Additional Commercial Paper[(b)]
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 9	$ 591	$ 591
Generation	Syndicated Revolver	5,300	—	1,139	4,161	4,161
Generation	Bilaterals	545	—	356	189	—
ComEd	Syndicated Revolver	1,000	—	2	998	998
PECO	Syndicated Revolver	600	—	—	600	600
BGE	Syndicated Revolver	600	—	1	599	599
Pepco	Syndicated Revolver	300	—	4	296	232
DPL	Syndicated Revolver	300	—	—	300	300
ACE	Syndicated Revolver	300	—	—	300	155

(a) Excludes $128 million of credit facility agreements arranged at minority and community banks at Generation, PECO, ComEd, BGE, Pepco, DPL and ACE. These facilities expired on October 12, 2018 and were renewed with aggregate commitments of $49 million, $33.5 million, $32.5 million, $5 million, $5 million, $5 million, and $5 million, respectively, through October 11, 2019. These facilities are solely utilized to issue letters of credit. As of September 30, 2018, letters of credit issued under these agreements for Generation and BGE totaled $5 million and $2 million, respectively. Excludes nonrecourse debt letters of credit, see Note 13 — Debt and Credit Agreements in the Exelon 2017 Form 10-K for additional information.

(b) Excludes $545 million bilateral credit facilities that do not back Generation's commercial paper program.

As of September 30, 2018, there were no borrowings under Generation's bilateral credit facilities.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's, BGE's, Pepco's, DPL's and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon Corporate	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

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The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon Corporate, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the nine months ended September 30, 2018:

	Exelon Corporate	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At September 30, 2018, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	6.87	11.16	12.28	7.86	9.32	5.81	7.53	5.30

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others’ credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE's indebtedness will not constitute an event of default with respect to the other PHI Utilities under the PHI Utilities' combined credit facility.

The absence of a material adverse change in Exelon's or PHI’s business, property, results of operations or financial condition is not a condition to the availability of credit under any of the borrowers' credit agreement. None of the credit agreements include any rating triggers.

Security Ratings

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

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

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

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Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of September 30, 2018, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended September 30, 2018		As of September 30, 2018
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 316	$ —	$ 167
Generation	227	—	—
PECO	—	(276)	—
BSC	—	(329)	(214)
PHI Corporate	—	(18)	(10)
PCI	57	(1)	57

PHI Intercompany Money Pool	During the Three Months Ended September 30, 2018		As of September 30, 2018
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 26	$ —	$ 1
PHISCO	3	(23)	2

Investments in Nuclear Decommissioning Trust Funds

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation’s NDT fund investment policy. Generation’s and CENG’s investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 13 —Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding the trust funds, the NRC’s minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements

Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. 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.

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Regulatory Authorizations

ComEd, PECO, BGE, Pepco, DPL and ACE are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	As of September 30, 2018					
	Short-term Financing Authority[a]			Remaining Long-term Financing Authority[a]		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd[b]	FERC	December 31, 2019	$ 2,500	ICC	2019 & 2021	$ 1,533
PECO[c]	FERC	December 31, 2019	1,500	PAPUC	December 31, 2018	575
BGE	FERC	December 31, 2019	700	MDPSC	N/A	400
Pepco	FERC	December 31, 2019	500	MDPSC / DCPSC	December 31, 2020	500
DPL	FERC	December 31, 2019	500	MDPSC / DPSC	December 31, 2020	150
ACE[d]	NJBPU	December 31, 2019	350	NJBPU	December 31, 2019	350

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) ComEd had $440 million available in long-term debt refinancing authority and $1,093 million available in new money long-term debt financing authority from the ICC as of September 30, 2018 and has an expiration date of June 1, 2019 and August 1, 2021, respectively.

(c) PECO is currently in the process renewing its long-term financing authority with PAPUC and expects approval before the end of the year.

(d) As a result of the October 16, 2018 debt issuance, the remaining long-term financing authority at ACE is zero. See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information regarding ACE debt issuance.

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 23 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2017 Form 10-K.

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 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 2017 Form 10-K.

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Item 3. Quantitative and Qualitative Disclosures 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 2017 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 2018 through 2020.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of September 30, 2018, the percentage of expected generation hedged is 98%-101%, 82%-85% and 48%-51% for 2018, 2019 and 2020, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation’s sales to the ComEd, PECO and BGE to serve their retail load.

A portion of Generation’s hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. 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, 2018 market conditions and hedged position would be an increase in pre-tax net income of approximately $11 million for 2018 and decreases of approximately $150 million and $475 million, respectively, for 2019 and 2020. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs

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constant. Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation’s portfolio. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Retail Competition

Constellation competes for retail customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail hedge generation output. Increased or more aggressive competition could adversely affect Generation's overall gross margins and profitability.

Proprietary Trading Activities

Proprietary trading portfolio activity for the nine months ended September 30, 2018 resulted in $39 million of pre-tax gains due to net mark-to-market gains of $14 million and realized gains of $25 million. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation’s total Revenue net of purchase power and fuel expense. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Fuel Procurement

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. Supply market conditions may make Generation’s procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 59% of Generation’s uranium concentrate requirements from 2018 through 2022 are supplied by three producers. 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 on Exelon’s and Generation’s results of operations, cash flows and financial positions.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC’s Order on December 19, 2012, ComEd’s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC’s December 18, 2013 Order approved the reduction of ComEd’s commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014.

ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which is further discussed in Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. The block energy contracts are considered derivatives and qualify for the normal purchases and normal sales scope exception under current

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derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. ComEd does not enter into derivatives for speculative or proprietary trading purposes. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on these contracts.

PECO, BGE, Pepco, DPL and ACE

BGE, Pepco, DPL and ACE have certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Other full requirements contracts are not derivatives.

PECO, BGE and DPL have also executed derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their results of operations or financial position.

PECO, BGE, Pepco, DPL and ACE do not enter into derivatives for speculative or proprietary trading purposes. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on these contracts.

Trading and Non-Trading Marketing Activities

The following tables detail Exelon's, Generation's, ComEd's, PHI's and DPL'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).

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The following table provides detail on changes in Exelon’s, Generation’s, ComEd’s, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from December 31, 2017 to September 30, 2018. 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 10 — 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, 2018 and December 31, 2017.

	Exelon	Generation	ComEd	PHI	DPL
Total mark-to-market energy contract net assets (liabilities) at December 31, 2017[a]	$ 667	$ 923	$ (256)	$ —	
Total change in fair value during 2018 of contracts recorded in results of operations	385	385	—	—	—
Reclassification to realized of contracts recorded in results of operations	(474)	(474)	—	—	—
Changes in fair value — recorded through regulatory assets and liabilities[b]	(2)	—	(3)	1	1
Changes in allocated collateral	(255)	(254)	—	(1)	(1)
Net option premium paid/(received)	36	36	—	—	—
Option premium amortization	(4)	(4)	—	—	—
Upfront payments and amortizations	(28)	(28)	—	—	—
Total mark-to-market energy contract net assets (liabilities) at September 30,2018[a]	$ 325	$ 584	$ (259)	$ —	$ —

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of September 30, 2018, ComEd recorded a regulatory liability of $259 million related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the nine months ended September 30, 2018, ComEd also recorded $9 million of decreases in fair value and an increase for realized losses due to settlements of $12 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

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 9 — 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.

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Exelon

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$7	$(44)	$(39)	$(6)	$(9)	$ 13	$ (78)
Prices provided by external sources (Level 2)	91	37	14	7	1	—	150
Prices based on model or other valuation methods (Level 3)[c]	1	353	71	(25)	(61)	(86)	253
Total	$99	$346	$46	$(24)	$(69)	$ (73)	$ 325

(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 to and received from counterparties (and offset against mark-to-market assets and liabilities) of $212 million at September 30, 2018.

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

Generation

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$7	$(44)	$(39)	$(6)	$(9)	$ 13	$ (78)
Prices provided by external sources (Level 2)	91	37	14	7	1	—	150
Prices based on model or other valuation methods (Level 3)	9	377	96	—	(36)	66	512
Total	$107	$370	$71	$1	$(44)	$ 79	$ 584

(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 to and received from counterparties (and offset against mark-to-market assets and liabilities) of $212 million at September 30, 2018.

ComEd

	Maturities Within						
	2018	2019	2020	2021	2022	2023 and Beyond	Total Fair Value
Commodity derivative contracts[a]:							
Prices based on model or other valuation methods (Level 3)	$(8)	$(24)	$(25)	$(25)	$(25)	$(152)	$ (259)

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

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Credit Risk, Collateral and Contingent-Related Features (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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for detailed information of credit risk, collateral and contingent-related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchases and normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 2018. The tables further disaggregate 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 figures 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. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $47 million, $26 million, $23 million, $39 million, $8 million and $6 million as of September 30, 2018, respectively.

Rating as of September 30, 2018	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	$ 647	$ —	$ 647	1	$ 176
Non-investment grade	101	20	81		
No external ratings					
Internally rated — investment grade	179	1	178		
Internally rated — non-investment grade	139	17	122		
Total	$ 1,066	$ 38	$ 1,028	1	$ 176

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2018	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$615	$ 30	$ 2	$ 647
Non-investment grade	104	(3)	—	101
No external ratings				
Internally rated — investment grade	120	30	29	179
Internally rated — non-investment grade	129	10	—	139
Total	$968	$ 67	$ 31	$ 1,066

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Net Credit Exposure by Type of Counterparty	As of September 30, 2018
Financial institutions	$ 19
Investor-owned utilities, marketers, power producers	572
Energy cooperatives and municipalities	357
Other	80
Total	$ 1,028

(a) As of September 30, 2018, credit collateral held from counterparties where Generation had credit exposure included $4 million of cash and $34 million of letters of credit.

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 2017 Annual Report on Form 10-K.

See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding credit exposure to suppliers.

Collateral (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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 17 — 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 results of operations, cash flows and financial positions. 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 ITEM 2. Liquidity and Capital Resources — Credit Matters — Exelon Credit Facilities for additional information.

The Utility Registrants

As of September 30, 2018, ComEd held $6 million in collateral from suppliers in association with energy procurement contracts, $20 million in collateral from suppliers for REC and ZEC contract obligations and $19 million in collateral from suppliers for long-term renewable energy contracts. BGE is not required to post collateral under its electric supply contracts but was holding an immaterial amount of collateral under its electric supply procurement contracts. BGE was not required to post collateral

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under its natural gas procurement contracts but was holding an immaterial amount of collateral under its natural gas procurement contracts. PECO, Pepco, DPL and ACE were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 6 — Regulatory Matters and Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

All Registrants participate in all, or some, of the established wholesale spot energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there are no spot energy markets, electricity is purchased and sold solely through bilateral agreements. For sales into the spot energy markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot energy market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

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

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize interest rate swaps to manage their interest rate exposure. At September 30, 2018, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $622 million of notional amounts of floating-to-fixed hedges outstanding. 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 $4 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2018. 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 10 — 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, 2018, Generation's decommissioning trust funds are reflected at fair value on 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

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investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $557 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. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the third quarter of 2018, each of Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's 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 all 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, 2018, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE concluded that such Registrant’s disclosure controls and procedures were effective to accomplish its objectives. All 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 have been no changes in internal control over financial reporting that occurred during the third quarter of 2018 that have materially affected, or are reasonably likely to materially affect, any of Exelon’s, Generation’s, ComEd’s, PECO’s, BGE’s, PHI’s, Pepco’s, DPL’s and ACE’s internal control over financial reporting.

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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 2017 Form 10-K and (b) Notes 6 — Regulatory Matters and 17 — 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 Exelon
At September 30, 2018, the Registrants' risk factors were consistent with the risk factors described in the Registrants' combined 2017 Form 10-K in ITEM 1A. RISK FACTORS.
Item 4. Mine Safety Disclosures
All Registrants
Not applicable to the Registrants.

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Item 6. Exhibits

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

Exhibit No.	Description
3.1	Amended and Restated Articles of Incorporation of Exelon Corporation (File No. 001-16169, Form 8-K dated July 27, 2018, Exhibit 3.1)
3.2	Amended and Restated Bylaws of Exelon Corporation (File No. 001-16169, Form 8-K dated July 27, 2018, Exhibit 3.2)
4.1	Supplemental Indenture dated as of July 26, 2018 from Commonwealth Edison Company 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 14, 2018, Exhibit 4.1)
4.2	Supplemental Indenture dated as of September 1, 2018 from PECO Energy Company to U.S. Bank National Association, as trustee (File No. 000-16844, Form 8-K dated September 11, 2018, Exhibit 4.1)
4.3	Supplemental Indenture dated as of October 9, 2018 from Atlantic City Electric Company to The Bank of New York Mellon, as trustee (File No. 001-03559, Form 8-K dated October 16, 2018, Exhibit 4.1)
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

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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, 2018 filed by the following officers for the following companies:

31-1 — Filed by Christopher M. Crane for Exelon Corporation

31-2 — Filed by Joseph Nigro for Exelon Corporation

31-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

31-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

31-5 — Filed by Joseph Dominguez 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 Calvin G. Butler, Jr. 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

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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, 2018 filed by the following officers for the following companies:

32-1 — Filed by Christopher M. Crane for Exelon Corporation

32-2 — Filed by Joseph Nigro for Exelon Corporation

32-3 — Filed by Kenneth W. Cornew for Exelon Generation Company, LLC

32-4 — Filed by Bryan P. Wright for Exelon Generation Company, LLC

32-5 — Filed by Joseph Dominguez 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 Calvin G. Butler, Jr. 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

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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	/s/ JOSEPH NIGRO
Christopher M. Crane	Joseph Nigro
President and Chief Executive Officer	Senior Executive Vice President and Chief Financial Officer
(Principal Executive Officer) and Director	(Principal Financial Officer)

/s/ FABIAN E. SOUZA
Fabian E. Souza
Senior Vice President and Corporate Controller
(Principal Accounting Officer)
November 1, 2018

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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/ KENNETH W. CORNEW	/s/ BRYAN P. WRIGHT
Kenneth W. Cornew	Bryan P. Wright
President and Chief Executive Officer	Senior Vice President and Chief Financial Officer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ MATTHEW N. BAUER
Matthew N. Bauer
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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/ JOSEPH DOMINGUEZ	/s/ JEANNE M. JONES
Joseph Dominguez	Jeanne M. Jones
Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ GERALD J. KOZEL
Gerald J. Kozel
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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	Robert J. Stefani
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ SCOTT A. BAILEY
Scott A. Bailey
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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/ CALVIN G. BUTLER, JR.	/s/ DAVID M. VAHOS
Calvin G. Butler, Jr.	David M. Vahos
Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
(Principal Executive Officer)	

/s/ ANDREW W. HOLMES
Andrew W. Holmes
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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	Phillip S. Barnett
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018

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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	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)

/s/ ROBERT M. AIKEN
Robert M. Aiken
Vice President and Controller
(Principal Accounting Officer)
November 1, 2018